Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation Further Call-In Telephonic Hearing	Docket No.: R-2025-3057164

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Judge's Chambers

State Office Building

801 Market Street

Philadelphia, PA

Monday, March 9, 2026

Commencing at 9:07 a.m.

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Docket No. R-2025-3057164

Hearing Date: March 9, 2026

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Timothy Rensch

Verification

OCA STATEMENT 6

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	
PPL Electric Utilities Corporation	**)**	**Docket No. R-2025-3057164**
	)	
	)	

TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

December 22, 2025

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND BUSINESS DESCRIPTION.

A. My name is Zach Teti. I am a Senior Regulatory Analyst at the Pennsylvania Office of Consumer Advocate ("OCA"). My office is located at 555 Walnut St, Harrisburg, PA 17101. The OCA is a state agency that represents the interests of Pennsylvania utility consumers before the Pennsylvania Public Utility Commission ("PUC"), federal regulatory agencies, and state and federal courts. The OCA was created by the Pennsylvania General Assembly in 1976 and is an independent office within the Office of Attorney General.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I received a B.A. degree in Economics from Millersville University (Millersville, PA) in 2013 and an M.S. in Energy Economics from Pennsylvania State University (University Park, PA) in 2021.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have twelve years of experience in the banking and energy industries, most recently specializing in organized wholesale and retail electricity markets. My background comprises energy market design and analysis; econometric research in an academic setting; and financial planning, analysis, and control in a banking setting. I was employed as a Senior Regulatory Analyst serving as a representative of the NEPOOL Markets Committee between 2021 and 2024, analyzing wholesale market design and its impact on default service procurement of electricity. In this position, I also wrote energy policy recommendations and helped with implementation of rulemaking ordered by the Federal Energy Regulatory Commission ("FERC"), such as FERC Order 2222 which aimed to better enable distributed energy resources (DERs) to

participate in the electricity markets run by regional grid operators.[1] I joined the OCA as a Senior Regulatory Analyst in April 2025.

Q. ON WHOSE BEHALF ARE YOU OFFERING THIS TESTIMONY?

A. I am offering this testimony on behalf of the OCA. My testimony is intended to address issues from the standpoint of residential customers of electricity. My comments also impact sizable customer-generators; that is, customers with distributed generation resources with output capacity that exceeds 100 kilowatts ("kW"), that are interconnected to the electric distribution system, and participate in net metering.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses certain elements of the proposed Maximum Registered Peak Load ("MRPL") methodology of PPL Electric Utilities Corporation ("PPL" or "Company") submitted to take effect in 2026. The Company has provided comments on specific issues that I will address including the importance of efficient procurement of the Company's default service passed through Generation Supply Charge-1 ("GSC-1").

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section I is an introduction. Section II presents a summary of the Company's proposed MRPL methodology. Section III presents my discussion of the Company's proposal and provides my recommendations concerning the Company's proposed MRPL methodology.

[1] https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy

Q. DO YOU HAVE ANY APPENDICES OR EXHIBITS TO YOUR TESTIMONY?

A. Yes. Attached to my testimony as Appendix A is my CV.

Q. ARE YOU RECOMMENDING THAT THE COMPANY'S PROPOSED MAXIMUM REGISTERED PEAK LOAD METHODOLOGY BE APPROVED BY THE PUC?

A. Yes. The overall default service supply portfolio and the specific default service procured on behalf of residential customers would likely benefit from the Company's proposed MRPL methodology. That is, energy procurement of the Company's default service passed through GSC-1 and GSC-2 would be more straightforward with this methodology. With the proposed methodology, Default Service Plan (DSP) suppliers would not need to factor fairly sizable, uncertain customer-generator output in their bid price as in the current methodology. Regarding this efficiency gain driven by the use of MRPL for rate classification, in OCA Interrogatory Set XXVII-5, PPL Witness Andrew Castanaro noted MRPL "does not impact the Company's Default Service Plan procurement efficiency. Rather, it classifies customers into the appropriate rate class based on their impact on the distribution system."[2] Admittedly, I expect there would be an improvement to energy procurement with this change; this is something that I believe PPL should further explore in this proceeding.

Q. WHY ARE YOU RECOMMENDING THAT THE COMPANY'S PROPOSED MAXIMUM REGISTERED PEAK LOAD METHODOLOGY BE APPROVED?

A. A priority in this matter should be to strive for fairness across customers and customer classes. The proposed MRPL methodology should accomplish fairness by improving

[2] OCA Interrogatory Set XXVII-5, attached as Exhibit ZT-2.

the procurement process for default service and simultaneously compensating customer-generators at a retail value that does not corrupt the efficiency of the procurement process. For these reasons, I am recommending that the Company's proposed MRPL methodology be approved by the PUC.

Q. ARE YOU MAKING ANY ADDITIONAL RECOMMENDATIONS?

A. Yes. This topic involves the complicated value proposition between (1) load reduction and its effect on PJM costs (and which customer class should be the recipient of these reduced costs while paying local customer-generators at a full retail rate), (2) compensating local customer-generators at a retail rate that consists of individual or multiple wholesale market components, and (3) the option of direct wholesale market participation and effectively stripping customer-generators out of the retail market and procurement scope. In this regulatory proceeding, I recommend that PPL demonstrate further clarity on this value proposition. OCA Interrogatory Set XXVII aimed to better understand the DSP impact of a customer-generator switching from GSC-1 to GSC-2 due to the proposed MRPL methodology, but I did receive greater clarity from PPL.[3]

[3] In OCA Interrogatory Set XXVII-1, Mr. Castanaro confirmed that "PPL Electric, as a Load Serving Entity, is assigned PJM costs based on its Default Service load during the peak period. If a customer-generator reduces the Company's default service load by generating during the peak period, PPL Electric would incur lower costs." Then, in OCA Interrogatory Set XXVII-2, Mr. Castanaro noted "the Company procures supply through full requirements load following contracts and block supply to match the aggregate default service load, not individual customer peak loads. This approach ensures supply aligns with actual consumption." Lastly, in OCA Interrogatory Set XXVII-4, Mr. Castanaro noted "the Company does not reconstitute or reinstate any NSPL reduction for the GSC-1 class in DSP procurement, nor does it adjust DSP revenues to recover costs from other GSC-1 customers to compensate customer-generators." After reviewing these responses, I might have more questions to better understand this process.

II. SUMMARY OF THE COMPANY'S MAXIMUM REGISTERED PEAK LOAD PROPOSAL

Q. HOW DOES THE COMPANY CURRENTLY DETERMINE MAXIMUM REGISTERED PEAK LOAD?

A. The Company uses "peak demand" to determine supply (capacity and energy) charge rate classification in its current tariff. Per the PPL tariff, "peak demand will be based on the customer's ICAP [installed capacity] peak load contribution assigned for the most recent PJM Planning Year."[4]

Q. HOW DOES PPL APPLY THE CURRENT DEFINITION OF MAXIMUM REGISTERED PEAK LOAD TO ASSIGN CUSTOMERS TO DEFAULT SERVICE RATE CLASSES?

A. In PPL Statement No. 15, Direct Testimony of Mr. Castanaro, at page 4, Mr. Castanaro explained that "under the current structure, the split between GSC-1 ('Small C&I') and GSC-2 ('Large C&I') customers is determined by a threshold of 100 kW peak demand. Customers with demand below this limit are categorized as GSC-1. However, no load net metering installations, despite their substantial generation output, have negligible net demand and, therefore, fall into the GSC-1 Small C&I category."

Q. HOW DOES THE COMPANY PROPOSE TO MODIFY THE DEFINITION OF MAXIMUM REGISTERED PEAK LOAD IN THIS PROCEEDING?

A. The Company proposes to add a new definition of "Maximum Registered Peak Load" in the Definitions section of the Tariff as follows:

> *"A customer's net demand contribution impact to the Company's default service procurement activity, as determined upon the net power flow from or into the Company's distribution or transmission system. The maximum registered peak load used to assign customers to their applicable rate schedule will be the customer's highest maximum registered peak load (kW) in the most*

[4] PPL Tariff, p. 71

recent 12-month period ending September 30. For new customers without a 12-month billing history, the maximum registered peak load shall be based on the Company's estimate using factors such as, but not limited to, similarly equipped buildings and similarly utilized buildings and square footage. As related to customer-generators, this estimate shall also be inclusive of the nameplate capacity of the generation system."[5]

Q. HOW WILL THE COMPANY'S PROPOSAL REGARDING MAXIMUM REGISTERED PEAK LOAD BE APPLIED?

A. The Company proposes using MRPL to determine which supply charge will be applied to its customers.

For GSC-1,

"The Generation Supply Charge-1 (GSC-1) shall be applied to each kilowatt-hour supplied to residential customers who take default service from the Company under Rate Schedule RS, small commercial and industrial customers who take Default Service under Rate Schedules GS-1, GS-3, BL, SA, SM (R), SHS, SLE, and SE and standby service for the foregoing rate schedules. The ***GSC-1 will not apply to those Rate Schedule GS-3 customers who have a Maximum Registered Peak Load of 100 kW or greater****, but the GSC-1 will apply to those Rate Schedule LP-4 customers who have a Maximum Registered Peak Load of less than 100 kW."*[6]

For GSC-2,

"The Generation Supply Charge-2 (GSC-2) shall be charged to customers in the Large Commercial & Industrial Customer Class who take default service from the Company under Rate Schedules GS-3, LP-4, LP-5, and standby service for the foregoing rate schedules. The ***GSC-2 will not apply to those Rate Schedule LP-4 customers who have a Maximum Registered Peak Load of less than 100 kW****, but the GSC-2 will apply to those Rate Schedule GS-3 customers who have a Maximum Registered Peak Load of 100 kW or greater. The GSC-2 shall have one rate option provision: Hourly Default Service Option."*[7]

[5] PPL's Exhibits GEO-1 and GEO-2, p. 147

[6] *Id.*, p. 62 (emphasis added).

[7] *Id.*, p. 69 (emphasis added).

Q. PLEASE RESTATE HOW THE DIFFERENT SUPPLY CHARGES WILL BE APPLIED.

A. GSC-1 and GSC-2 are applied to customers that take default service. The Net Metering for Renewable Customer-Generators Rider applies to RS, GS-1, GS-3 and LP-4 Rate Schedules. For all RS customers, the generation charge is GSC-1; that is, RS customers pay at a GSC-1 rate if they are net buyers and receive GSC-1 if they are net sellers. Focusing on the rate schedules that apply the Net Metering for Renewable Customer-Generators Rider, small commercial and industrial ("Small C&I") customers may be applied to the GS-1, GS-3 and LP-4. For these Small C&I customers, the charge is determined by MRPL; either (1) Small C&I LP-4 customers who have a MRPL of less than 100 kW will be applied to GSC-1, or (2) Small C&I LP-4 customers who have a MRPL of greater than 100 kW will be applied to GSC-2. Additionally, either (1) Small C&I GS-3 customers who have a MRPL of less than 100 kW will be applied to GSC-1, or (2) Small C&I GS-3 customers who have a MRPL of greater than 100 kW will be applied to GSC-2.

Q. PLEASE CHARACTERIZE THE GSC-1 AND GSC-2 SUPPLY CHARGES.

A. GSC-1 is procurement-based. GSC-1 is based on "the total estimated direct and indirect costs incurred by the Company to acquire generation supply from any source on behalf of participating Basic Utility Supply Service ('BUSS') customers on the Fixed Price Option in the applicable Customer Class."[8] GSC-2 is market-based with multiple components. An example of a component is:

> *"GSC-2 Energy Charge per KWH: The product of actual real-time LMPs at the PPL Residual Aggregate Node as reported by PJM for each hour of the billing*

[8] *Id.*, p. 290

month expressed in cents per KWH multiplied by the customer's actual energy use, adjusted for losses, during each hour of the billing month."[9]

The proposed delineation of service rate by MRPL is created to procure an efficient quantity of supply for the bulk of customers via DSP suppliers in GSC-1. This approach ringfences similarly situated customers apart from large customers and virtually commercial customers with generation that exceeds 100 kW. The GSC-2 rate is still a retail rate and includes much of the same essential cost components as the GSC-1 rate.

Q. IS THIS PROPOSAL A NEW METHODOLOGY?

A. No, not really. In PPL Statement No. 15, Direct Testimony of Andrew Castanaro, at page 8,[10] Mr. Castanaro explained that "In the Default Service Plan V ('DSP V') proceeding for UGI Utilities, Inc. – Electric Division ('UGI Electric') at Docket No. P-2024-3049343, et al., the Commission approved a very similar proposal, under which UGI Electric classifies customers based on their 'supply peak load impact.' Although the Company is using the term 'maximum registered peak load' instead of 'supply peak load impact,' the customer classification methodologies are effectively the same."

Q. DID THE COMPANY ADDRESS THIS TARIFF CHANGE IN TESTIMONY?

A. Yes. Mr. Castanaro explained that "the Company's currently effective tariff, which was last updated in the 2015 Rate Case, does not classify customers based on their maximum registered peak load as set forth in the proposed retail tariff. Instead, for example, a small commercial customer's demand is determined based on their load independent of the nameplate capacity of any behind-the-meter generation. This current practice fails to reflect the stress that the behind-the-meter generation puts on PPL Electric's distribution system. Additionally, **the current classification results in non-**

[9] *Id.*, p. 69

[10] Direct Testimony of Andrew Castanaro, p. 8

net metering Small C&I default service customers disproportionately subsidizing the annual cash-outs of customer generators that are, effectively, merchant generators."[11]

III. DISCUSSION AND RECOMMENDATIONS

A. Importance of Efficient Procurement of the Default Service Served on the GSC-1

Q. DESCRIBE THE TREND OF PPL'S GSC-1.

A. On a bi-annual basis, the OCA reviews calculations filed by the Company which highlight Projected Energy Procurement Expenses and the supply charge rates for GSC-1 and GSC-2. Lately, the GSC-1 generation charge rate and total costs have been increasing, which heightens scrutiny on this matter.[12] While much of this increase in rates is likely the effect of changes at the wholesale level, the OCA is still focused on any matter that impacts supply charges to residential customers.

Q. DOES THE COMPANY ASSESS THE IMPACT OF THE MAXIMUM REGISTERED PEAK LOAD PROPOSAL?

A. Yes. In PPL Statement No. 15, Direct Testimony of Andrew Castanaro, PPL Electric Exhibits AC-1 through AC-3 "estimates that the annual cash-outs for the Small C&I customer class will be approximately $60 million to over $300 million by 2029" in the status quo.[13] In the proposed MRPL methodology, many customer-generators would be reclassified to GSC-2 which would involve a cash-out at a retail rate that captures

[11] *Id.*, p. 6 (emphasis added).

[12] PPL Electric Utilities Corporation Calculation and Supplement No. 402 to Tariff – Electric PA. P.U.C. No. 201 for the Generation Supply Charge – 1 Docket No. was most recently served by the Company to the OCA on October 31, 2025.

[13] Joint Solar Advocates Interrogatory Set I-26 was helpful in better understanding this analysis.

components aligned to wholesale markets, rather than a rate determined by the more imprecise blocks procured in the DSP for GSC-1.

Q. ARE YOU CONCERNED ABOUT THE PREVIOUSLY NOTED SUBSIDIZATION VIA ANNUAL CASH-OUTS OF CUSTOMER GENERATORS?

A. Yes, however, I would rather think of this as inefficiency that will be improved. Mr. Castanaro explained that "the GSC-2 is calculated using real-time pricing based on the hourly generation needs of the customer class. This differs from the Small C&I GSC-1 rate, which is based on a combination of load following 12- and 24-month full requirements contracts."[14] The contracts in this latter approach will include risk premiums, administrative costs, and other spreads of which the Company will not be privy. Because these customer-generators are virtually commercial customers, the GSC-2 pricing scheme seems more appropriate and would improve procurement efficiency for the procurement of GSC-1, particularly Small C&I GSC-1.

Q. PLEASE ELABORATE ON THE RISK PREMIUMS THAT MAY BE A CAUSE FOR CONCERN REGARDING THIS CASH-OUT?

A. In the DSP V proceeding for UGI Electric at Docket No. P-2024-3049343, OCA Witness Serhan Ogur explained that the inclusion of customer-generators in full requirement contracts might cause risk premiums for switching risk and volumetric risk. I am informed by counsel that the Administrative Law Judge and the Commission credited Mr. Ogur's testimony when they approved UGI Electric's proposed customer classification methodology, which Mr. Ogur supported.[15] For both situations, DSP suppliers would build risk premiums to ensure they have enough revenue to

[14] Direct Testimony of Andrew Castanaro, p. 7

[15] *UGI DSP V*, Docket No. P-2024-3049343, Recommended Decision (Dec. 3, 2024) at 26-41, Order (Feb. 20, 2025) at 60.

compensate customer-generators. Again, compensating customer-generators via the GSC-2 pricing scheme should improve procurement efficiency for the procurement of GSC-1, particularly Small C&I GSC-1.

Q. WILL THE PROPOSED MAXIMUM REGISTERED PEAK LOAD METHODOLOGY MITIGATE THE NEED FOR THIS RISK PREMIUM?

A. Yes. The proposed MRPL methodology should reduce, over time, the need for suppliers to include this risk premium in their offers when participating in default service procurement auctions to be passed through GSC-1.

Q. HAVE YOU CONDUCTED AN ANALYSIS ON THESE RISK PREMIUMS?

A. No, for the following reasons: (1) the OCA is not permitted to see bid details such as these following the completion of default service procurement auctions; and (2) given this lack of information, no further analysis on risk premiums was performed.

Q. PLEASE ALSO PROVIDE THE RELEVANT PORITONS OF THE PUC'S RECENT *UGI ELECTRIC* DECISION (DOCKET NO. P-2024-3049343) RELATED TO RISK PREMIUMS DRIVEN BY CUSTOMER-GENERATOR UNCERTAINTY.

A. From the PUC's Opinion and Order:

> The Company determined that if large customer-generators were to be included in the GSR-1 group, then: (1) their output would decrease GSR-1 group load and tranche size; (2) there is substantial question as to the level of output and timing of when these projects will become operational; and (3) these large customer-generators have the ability to leave default service at any time and participate in the wholesale market, thereby creating an attrition risk if projects opt to leave GSR-1 service and shop their output elsewhere. UGI argued that each of these factors would substantially increase risk for wholesale suppliers, causing higher bid premiums and likely reducing the number of competitive bidders.[16]

[16] PA PUC Opinion and Order, p. 23

Q. PLEASE EXPLAIN THE IMPORTANCE OF EFFICIENT PROCUREMENT OF DEFAULT SERVICE PASSED THROUGH GSC-1.

A. I am informed by counsel that utilities must meet their statutory responsibilities by procuring a default service portfolio that is designed to ensure service at the least cost over time.[17] To achieve this, utilities must ensure reliable electricity supply by engaging in prudently procured load supply contracts in a streamlined manner, which requires a clear understanding of forecasted load for a somewhat nuanced base of customers. That is, getting the quantity correct is key for the efficient procurement of default service supply that will be passed through to customers at GSC-1. Implementation of the proposed MRPL methodology should reduce the uncertainty of output from large customer-generators (output capacity > 100 kW), helping with the efficiency of this procurement. By designating large customer-generators as GSC-2 customers, the task of efficient default service procurement for the bulk of customers becomes more achievable.

B. Other Considerations Regarding the Maximum Registered Peak Load Methodology

Q. WILL THE RECLASSIFICATION OF CUSTOMER-GENERATORS TO GSC-2 IMPACT THE WAY PJM COSTS ARE ASSIGNED TO PPL AND RECOVERED FROM CUSTOMERS IN PPL?

A. In PPL Response to Joint Solar Advocates Interrogatory I-21, Mr. Castanaro explained that "to the extent the NEM customer-generator projects provide output during the 5 coincident peaks ('5CP'), it would reduce PJM capacity cost obligations for all customer classes. However, the Company has not performed any studies that would quantify those benefits."[18] It is my expectation that the supply charge designation

[17] 52 Pa. Code § 54.185. Default service programs and periods of service.
[18] PPL Response to Joint Solar Advocates Interrogatory Set I-21

would not impact the level at which PJM costs are assigned to PPL. But after reviewing PPL responses to OCA Interrogatory Set XXVII, I would like to better understand the process by which capacity costs and compensation to customer-generators are recovered by PPL customers.

Q. WILL THE COMPANY'S PROPOSED MAXIMUM REGISTERED PEAK LOAD METHODOLOGY IMPACT RESIDENTIAL CUSTOMERS WITH DISTRIBUTED ENERGY RESOURCES?

A. No, not substantially. A vast majority of residential customers with DER have DER systems with output capacity of much less than 100 kW (most are order(s) of magnitude 10 smaller) and accordingly they will remain in the GSC-1 classification.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

OCA STATEMENT 5R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	
PPL Electric Utilities Corporation	**)**	**Docket No. R-2025-3057164**
	)	
	)	

EXHIBIT TO THE

TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

December 22, 2025

CURRICULUM VITAE OF ZACH TETI

PROFESSIONAL EXPERIENCE

Pennsylvania Office of Consumer Advocate • Harrisburg, PA • April 2025-Present • Senior Regulatory Analyst
Customized Energy Solutions • Philadelphia, PA • April 2024-September 2024 (Contract) • Compliance Analyst
Avangrid • Orange, CT • May 2021-April 2024 • Regulatory Analyst – FERC, ISO New England & New York ISO
Penn State University • University Park, PA • August 2019-May 2021 • Research Assistant – Energy Economics
TD Bank • Mount Laurel, NJ • February 2018-July 2019 • Assistant Vice President – Retail Lending Financial Analysis
JP Morgan Chase • Newark, DE • July 2013-February 2018
Budgeting, Forecasting and Analysis - Associate – Consumer Banking Technology • July 2017-February 2018
Financial Control – Associate & Analyst – International Trade Finance • July 2013-July 2017
Lancaster County Workforce Investment Board • Lancaster, PA • December 2012-May 2013 • Research Intern

EDUCATION & OTHER UNDERTAKINGS

Penn State University • University Park, PA • May 2021 • MS in Energy Economics
Millersville University • Millersville, PA • May 2013 • BA in Quantitative Economics, minor in Statistics
Curator for the Global Shapers Philadelphia Hub – World Economic Forum Initiative • September 2017-May 2021

PPL Electric Utilities Corporation
Response to the Set XXVII Data Requests of the
Office of Consumer Advocate (OCA) Dated December 8, 2025
Docket No. R-2025-3057164

OCA XXVII-5 Refer to PPL response to OCA-27-4. Does PPL view the proposed adjustment to its tariff definition of "Maximum Registered Peak Load" as an improvement in DSP procurement efficiency?

PPL Electric Response The proposed definition of Maximum Registered Peak Load does not impact the Company's Default Service Plan procurement efficiency. Rather, it classifies customers into the appropriate rate class based on their impact on the distribution system.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2025-3057164
PPL Electric Utilities Corporation	:	

VERIFICATION

I, Zachary F. Teti, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 6, are true and correct to the best of my knowledge, information, belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: December 22, 2025

Signature: /s/ Zachary F. Teti
Zachary F. Teti

Address: 555 Walnut St.,
Harrisburg, PA 17101

OCA STATEMENT 6R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	
PPL Electric Utilities Corporation	**)**	**Docket No. R-2025-3057164**
	)	
	)	

REBUTTAL TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

January 23, 2026

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OCA Exhibit ZT-1R – Numerical Example of DSP

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND BUSINESS DESCRIPTION.

A. My name is Zach Teti. I am a Senior Regulatory Analyst at the Pennsylvania Office of Consumer Advocate ("OCA"). My office is located at 555 Walnut St, Harrisburg, PA 17101. The OCA is a state agency that represents the interests of Pennsylvania utility consumers before the Pennsylvania Public Utility Commission ("PUC"), federal regulatory agencies, and state and federal courts. The OCA was created by the Pennsylvania General Assembly in 1976 and is an independent office within the Office of Attorney General.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement 6 on December 22, 2025.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I am responding to the Direct Testimony of Kevin M. Lucas, Joint Solar Advocates Statement ("JSA") No. 1, Direct Testimony of Justin R. Barnes, JSA Statement No. 2, and Direct Testimony of Guy Sharfman, Customer-Generator Coalition ("CGC") Statement No. 1 (altogether, "Parties"). My rebuttal testimony addresses certain elements of the proposed Maximum Registered Peak Load ("MRPL") methodology of PPL Electric Utilities Corporation ("PPL" or "Company") submitted to take effect in 2026. The Company and the above Parties have provided helpful comments on specific issues that I will address including: (1) the complexities of the default service plan ("DSP") conducted by the Company; (2) the importance of efficient procurement of the Company's DSP passed through to customers via Generation Supply Charge-1

("GSC-1") and GSC-2; (3) the fairness of the rate of compensation for energy produced by customer-generators; and (4) the weighing of alternatives not yet considered.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. Section I is an introduction. Section II presents a brief summary of the Company's proposed MRPL methodology. Section III provides a response to Mr. Lucas and Mr. Sharfman focusing on the importance of efficiency of the DSP process and fairness of the rate of compensation for energy produced by customer-generators. Section IV, the final section of my Rebuttal Testimony, responds to the recommendations proposed by Mr. Barnes.

Q. ARE YOU ATTACHING EXHIBITS TO YOUR REBUTTAL TESTIMONY?

A. Yes. Through a numerical example, OCA Exhibit ZT-1R succinctly illustrates the interaction between energy procured in the DSP and compensation to customer-generators for excess generation. OCA Exhibit ZT-1R shows the similarities and differences between the status quo and the MRPL proposal. I created this numerical example as cash flow arrangements were a topic in a few interrogatories and testimony discussions submitted by the Parties that will be later discussed.

Q. ARE YOU RECOMMENDING THAT THE COMPANY'S PROPOSED MRPL METHODOLOGY BE APPROVED BY THE PUC?

A. Yes, I am. My review of other parties' testimony in this proceeding has not changed my recommendation. The overall default service supply portfolio would benefit from a re-examination of the process by which the Company determines retail rate-based compensation for excess generation and, subsequently, the allocation of these costs.

Q. ARE YOU MAKING ANY ADDITIONAL RECOMMENDATIONS?

A. Yes. As just stated, in this regulatory proceeding, to understand the detailed complexities of the Company's DSP procurement and billing has required a lengthy review of disjointed testimony and interrogatory responses. In this regulatory proceeding and prior to any accepted tariff change, clarity should be reached on this subject.

II. SUMMARY OF THE COMPANY'S MAXIMUM REGISTERED PEAK LOAD PROPOSAL

Q. PLEASE RE-SUMMARIZE THE COMPANY'S MAXIMUM REGISTERED PEAK LOAD PROPOSAL.

A. In the Company's current tariff, "peak demand" determines supply (capacity and energy) charge rate classification and is a measurement of demand, or peak load contribution (PLC).[1] The MRPL proposal will capture net power flow, classifying customer-generators as GSC-2 if they inject greater than 100 kW of power to the grid.[2] GSC-2 is market-based, with multiple components such as an energy charge, and is likely more affordable than GSC-1, which is procurement-based.

Q. HOW DID THE COMPANY DESCRIBE THE RATIONALE FOR THIS TARIFF CHANGE?

A. Mr. Castanaro explained that "the Company's currently effective tariff, which was last updated in the 2015 Rate Case, does not classify customers based on their maximum registered peak load as set forth in the proposed retail tariff. Instead, for example, a small commercial customer's demand is determined based on their load independent of the nameplate capacity of any behind-the-meter generation. This current practice

[1] PPL Tariff, p. 71

[2] PPL's Exhibits GEO-1 and GEO-2, p. 147

fails to reflect the stress that the behind-the-meter generation puts on PPL Electric's distribution system. Additionally, the current classification results in non-net metering Small C&I default service customers disproportionately subsidizing the annual cash-outs of customer generators that are, effectively, merchant generators."[3]

III. RESPONSE TO JSA WITNESS LUCAS AND CGC WITNESS SHARFMAN

Q. CAN YOU BRIEFLY SUMMARIZE THE OPPOSITION OF JSA WITNESS LUCAS AND CGC WITNESS SHARFMAN TO THE MRPL PROPOSAL?

A. Yes. Mr. Lucas is concerned by this claim where his "review of [discovery responses] demonstrated that PPL's 'grid stress' and 'subsidization' arguments are poorly supported, contain unreasonable assumptions, and are contradicted by facts and information provided by the Company itself."[4] Mr. Lucas and Mr. Sharfman also voiced opposition to the MRPL proposal because of the anticipated negative effect that the transition will have on the compensation that customer-generators receive for excess generation.

Q. WHAT ARE YOUR THOUGHTS ON PPL'S SUPPORT FOR ITS MRPL PROPOSAL?

A. I understand PPL witness Castanaro deems the current compensation to customer-generators a "subsidization" because merchant generators are being compensated at the higher retail rate, which will include risk premiums, administrative costs, and other spreads of which the Company is not privy, which results from procurement, and is compensated out of the default service rates of customers that do not share similar

[3] *Id.*, p. 6.
[4] Direct Testimony of Kevin M. Lucas, p. 22

sophistication or risk characteristics. Above, Mr. Castanaro also declares which customers are currently assigned the burden of these costs: Small C&I customers. As JSA witness Lucas points out, Small C&I customers are also the beneficiaries of net metering through reduced procurement quantity in the DSP. Altogether, I would rather think of the MRPL proposal as an approach to improving procurement efficiency and a continued allowance of compensation at a retail rate that is aligned with what these customer-generators are offering (rather than the elimination of subsidization).

A. Efficiency of Default Service Procurement

Q. PLEASE DISCUSS SOME OF THE CONCERNS REGARDING THE LEVEL OF EXCESS GENERATION COMPENSATION SHOWN IN MR. CASTANARO'S EXHIBITS AC1-3 RAISED BY MR. LUCAS IN JSA STATEMENT NO. 1.

A. Mr. Lucas focused on the analysis done by Mr. Castanaro in Exhibits AC1-3 and among his concerns, he surmised that (1) the Company overstated the forecasted magnitude and value of excess generation and (2) did not incorporate savings due to the reduction in load from net metering.

Q. HOW DO YOU RESPOND?

A. I believe both of Mr. Lucas's concerns are valid, subject to the caveat that the dispute of the quality of PPL's forecast is an example of the difficult interaction between business practices conducted by the Company and the uncertainty of somewhat external factors. The deviation between the Company and Mr. Lucas's estimations highlights one of the inefficiencies which I believe FERC Order 2222 meant to resolve, ensuring wholesale market signals are at the right level and directly compensating distributed energy resources for the provided service of capacity. Further, I view the use of GSC-

2 as a way to remove this chance for error, an efficiency improvement as I stated in Direct Testimony.

Q. DID MR. LUCAS DISCUSS CASH FLOW ARRANGEMENTS FOR COMPENSATION OF EXCESS GENERATION?

A. Yes. I found Mr. Lucas's clarification that "'SCI Net Metering Expense from MGs' in PPL Witness Castanaro's workpapers, is added back to SCI procurements costs in the reconciliation process via the 'E Factor Rate'"[5] to be informative. Mr. Lucas also noted that "because the excess generation cost is now recovered in the next Default Service Plan cycle, it pushes up the total energy supply procurement cost."[6] I include OCA Exhibit ZT-1R to illustrate the cash flow arrangements discussed by Mr. Lucas as I understand them in the Appendix.[7]

B. MRPL Effect on Customer-Generator Compensation

Q. PLEASE DISCUSS YOUR THOUGHTS ON REGULATORY CHANGES AND UTILITY TARIFFS AS DISCUSSED BY MR. LUCAS.

A. Mr. Lucas states that "certainty and predictability are key components to any business enterprise and no different for customer-generators."[8] In six years of policy experience in the energy industry, I have found it to ebb and flow during this time with many differences in spatial and temporal political views trickling down into regulatory environments. The transient rules at regional transmission organizations are surely no different, with market rule changes keeping up with the innovation of technology.

[5] Direct Testimony of Kevin M. Lucas, p. 38
[6] *Id.*
[7] OCA Exhibit ZT-2.
[8] Direct Testimony of Kevin M. Lucas, p. 14

Q. WHY ARE MR. LUCAS AND MR. SHARFMAN CONCERNED WITH THE PROPOSED MRPL PROPOSAL?

A. In the proposed MRPL methodology, net metering compensation for large customer-generators (output capacity > 100 kW) at a more advantageous rate will be discontinued. As stated by Mr. Sharfman, "PPL's proposed tariff changes effectively renege on the solar crediting structure that drove solar expansion in PPL's service area. The proposed changes will harm many GSC-1 customers by reclassifying them as GSC-2 customers, thereby greatly lowering the revenue they currently receive for excess solar generation."[9]

Q. PLEASE ELABORATE ON THIS PROMISE.

A. The energy industry does not really contain promises on which to renege and, because of this, there are many layers of hedging activity in the industry. PPL's DSP for GSC-1 customers is one of these hedges. If the commodity were not volatile then there would be no need for a DSP with its many solicitations, tranches, and highly confidential bidding. Still, Small C&I customers have seen rates increase 33% from $0.07061/kWh in the June-November 2024 DSP cycle to $0.09379/kWh in the current DSP cycle.[10]

Q. WHAT IS ASSURED TO CUSTOMER-GENERATORS UNDER THE ALTERNATIVE ENERGY PORTFOLIO STANDARDS ACT?

A. Under the AEPS Act, customer-generators will be compensated at a "full retail rate."[11] Some customers of the Company pay at GSC-2, a reasonable example of one of these

[9] Direct Testimony of Guy Sharfman, p. 6

[10] Calculation and Supplement No. 402 to PPL Electric's Tariff – Electric Pa. P.U.C. No. 201 for the Generation Supply Charge – 1 ("GSC-1")

[11] CHAPTER 75. ALTERNATIVE ENERGY PORTFOLIO STANDARDS § 75.13. General provisions.

(d) An [electric distribution company] (EDC) and [default service provider] (DSP) shall credit a customer-generator at the full retail kilowatt-hour rate, which shall include generation, transmission and distribution charges, for each kilowatt-hour produced by a Tier I or Tier II resource installed on the customer-generator's

retail rates considered by the PUC. Additionally, the Company provides a table of the Price to Compare Historical Rates, which is not limited to customers that pay GSC-1.[12] Customer-generators are assured compensation at a "full retail rate." Below, I concur with Mr. Barnes and his proposal to allow a customer to register a negative peak load contribution (PLC) so that the compensation for capacity more accurately reflects customer-generators' system-wide peak load shaving.

IV. RESPONSE TO JSA WITNESS BARNES

Q. PLEASE DESCRIBE MR. BARNES' VIEW ON THE MRPL PROPOSAL.

A. Mr. Barnes opposes the change to the MRPL but proposes that, if it is approved, then such approval should be contingent on granting legacy rights to current GSC-1 customer-generators which have little to no demand for energy, which he refers to as "FTM DG" customers.[13] According to Mr. Barnes, the output from customer-generators accomplishes a few things: (1) power is simply produced and consumed by other customers, (2) the capacity to produce this power offsets capacity needed at the wholesale level (and is thus de facto capacity) and (3) because power is produced from solar energy in many cases, customer-generators help accomplish targets in the Alternative Energy Portfolio Standards (AEPS) Act.[14] I agree that there should be a

side of the electric revenue meter, up to the total amount of electricity used by that customer during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC and DSP deliver to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's kilowatt-hour usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours that are not offset by electricity used by the customer in subsequent billing periods shall continue to accumulate until the end of the year. For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate.

(e) At the end of each year, the DSP shall compensate the customer-generator for any remaining excess kilowatt hours generated by the customer-generator that were not previously credited against the customer-generator's usage in prior billing periods at the DSP's price to compare rate.

[12] https://www.pplelectric.com/site/Other-Parties/Electricity-Suppliers/Supplier-Reference/Price-Compare

[13] Direct Testimony of Justin Barnes, pp. 32-45.

[14] *Id.*, p. 18.

revenue stream for all these benefits; however, compensating these customer-generators, which are virtually commercial generators, at GSC-1 for offsetting the load considered in the DSP is not necessary.

Q. PLEASE INCLUDE THE SUMMARY OF MR. BARNES' RECOMMENDATIONS

A. The proposal includes the following elements:

1) The Commission should direct PPL to modify how it determines customer peak loads for the purposes of generation capacity and transmission cost allocation to: (i) allow those values to reflect "negative loads" produced by FTM DG customers, and (ii) apply the cost savings benefits of those negative loads to reduce the allocation of the relevant costs to the rate class in which the FTM DG customer resides.
2) The Commission should direct the Company to improve alignment of the GSC-2 rate with cost causation by allowing customers to register "negative peak loads", and revise the PTC-based compensation for excess NEM generation to include a credit for any FTM DG customer with a negative peak load value.
3) The Commission should adopt my proposal for establishing legacy rights under the GSC-1 rate for all FTM DG projects that are operational or under construction as of the date of PPL's rate filing application.
4) The Commission should adopt my proposal for establishing legacy rights under the GSC-1 rate for a subset of planned but not operational FTM DG projects that meet certain maturity and financial commitment milestones, conditioned on the FTM DG project owner also agreeing to surrender AECs produced by the project to PPL at no cost for the duration of the legacy rights term.[15]

Q. DO YOU AGREE WITH MR. BARNES' PROPOSALS 1 AND 2 REGARDING THE VALUATION OF "NEGATIVE LOADS"?

A. Yes, I do. First, I agree that the customer-generators in PPL do functionally reduce the PJM capacity cost obligations for PPL. Then, I posit the change in the MRPL methodology should not impact this function. Presently, this output enables PPL to reduce the DSP procurement amount, which is a benefit to Small C&I customers, as

[15] Direct Testimony of Justin R. Barnes, p. 46

discussed in multiple interrogatories in this regulatory proceeding.[16] However, I am advised by counsel that the FERC-jurisdictional aspects of PJM's tariff and PPL's supplement to that tariff which address the negative PLC proposal may be beyond the scope of this proceeding.

Q. WHY DO YOU AGREE WITH MR. BARNES' NEGATIVE PLC PROPOSAL?

A. I find the negative PLC proposal to be equitable and more in the spirit of the AEPS Act. Consideration should be carefully made if customer-generators remain GSC-1 customers; that is, these customer-generators should not in any way benefit twice via compensation at this higher retail rate and additionally compensated for a negative PLC. Then, I do not view excess generation compensation as a substitute or superior to wholesale market participation. Much effort and advocacy for the participation of distributed energy resources in wholesale markets was employed in the past seven or eight years;[17] ideally, some of these resources will consider directly participating in wholesale markets through an aggregation. In the spirit of FERC Order No. 2222, I believe being "compensated for all products and services for which they are technically capable of providing" in wholesale markets could be more streamlined than the alternative of compensation at GSC-2, the use of an E Factor Rate for recovery, and other uncertain net metering considerations in a DSP.

[16] PPL Response to JSA Interrogatory IV-4b

[17] Comments of the Solar Energy Industries Association in Support of DER Market Participation: "SEIA encourages the Commission to design market rules that are non-discriminatory and allow all resources the opportunity to be compensated for all products and services for which they are technically capable of providing."

Q. DO YOU THINK MR. BARNES' NEGATIVE PLC PROPOSAL IS IN SCOPE FOR THIS REGULATORY PROCEEDING?

A. Again, I am advised by counsel that the FERC-jurisdictional aspects of PJM's tariff and PPL's supplement to that tariff which address the negative PLC proposal may be beyond the scope of this proceeding. If this is true and the Commission finds that PPL cannot make that adjustment in this regulatory proceeding, I would still recommend that PPL pursue implementing this recommendation at the appropriate level.

Q. HOW IS THE NEGATIVE CONCEPT ILLUSTRATED IN YOUR NUMERICAL EXAMPLE?

A. I aimed to incorporate this in OCA Exhibit ZT-2. Line [K] would require a crediting mechanism reducing the PJM capacity costs for all GSC-2 customers. Alternatively (to Line [K]), revenue raised associated with an un-adjusted GSC-2 Capacity Charge component could be used as compensation for customer-generators as this amount will not be due to PJM. Once more, customer-generators in PPL functionally reduce the PJM capacity cost obligations for PPL as a whole, and this should be applied to some base of customers. Line [T] would revisit this value for compensation to customer-generators. Line [U] would incorporate both Line [M] the GSC-2 Capacity Charge and Line [N] GSC-2 Energy Charge per kWh. This numerical example is meant to be illustrative with proxy numbers. I will be curious if other parties have considered the mechanics of this issue or have considered more efficient approaches.

Q. WHY DO YOU PREFER THIS PARADIGM TO THE STATUS QUO?

A. As shown in OCA Exhibit ZT-1R, I believe this paradigm will have a positive effect on the GSC-1 rate and thus the overall procurement cost in [AB]. Because Small C&I customers virtually pay for this capacity with or without net metering through either the core DSP procurement or the E Factor Reconciliation, both scenarios are effectively

the same with respect to the function but are not the same with respect to the actual cost to customers. That is, a risk premium is included in the status quo and detailed on the second page of OCA Exhibit ZT-1R.

Q. DO YOU AGREE WITH PROPOSALS 3 AND 4 REGARDING LEGACY RIGHTS?

A. No, for three reasons. (1) Wholesale generators deal with ebbs and flow of both prevailing prices in flux and changing rules that govern the various wholesale energy markets. So, I do not believe a transition mechanism establishing "legacy rights" is justified. (2) I do not believe a transition mechanism of this sort is necessary, either. Again, because Small C&I customers pay for this capacity with or without net metering through either the core DSP procurement or the E Factor Reconciliation, I view both scenarios producing effectively the same costs (with the exception of a risk premium and other, non-wholesale market costs included in the default service retail rate), meaning there should be no "rate shock" to customers.[18] (3) The "FTM DG project owner also agreeing to surrender AECs produced by the project to PPL at no cost for the duration of the legacy rights term" strikes me as a bargain rather than an intuitive approach to power procurement and potentially myopic as it appears justified by the quantitative analysis done by Mr. Barnes.[19]

Q. WOULD TRANSITIONING TO THIS DEFAULT SERVICE PLAN APPROACH REQUIRE A TRANSITION MECHANISM AS PROPOSED BY MR. BARNES?

A. No. I don't believe a transition mechanism would be required as one grossed up billing stream would replace two billing streams for GSC-1 customers of the Company; these

[18] Direct Testimony of Justin R. Barnes, p. 34
[19] *Id.,* p. 20-25

current streams being: (1) revenue associated with the core procurement from DSP suppliers considerate of net metering and (2) revenue through the E Factor Rate, which is a lagged recovery of under-collection associated with output from net metering. In OCA Exhibit ZT-1R, I extend this exhibit to illustrate the similarities and differences between the status quo versus the MRPL proposal.

Q. ALTOGETHER, DO YOU THINK THE MAXIMUM REGISTERED PEAK LOAD PROPOSAL, THE ADDITION OF MR. BARNES' PROPOSALS 1 AND 2, AND THE REJECTION OF PROPOSALS 3 AND 4 WOULD BE A FAIR OUTCOME?

A. Yes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

OCA STATEMENT 6R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

EXHIBITS TO THE

REBUTTAL TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

January 23, 2026

MAXIMUM REGISTERED PEAK LOAD (MRPL) - NUMERICAL EXAMPLE

			[1] Status Quo	[2] MRPL Proposal	[3] = [2] - [1] Difference
	GSC-1 SCI				
[A]	Gross Load (w/ Losses)	*MWh*	500,000	500,000	0
[B]	Net Metering (DSP Adjustment)	*MWh*	(25,000)	0	25,000
[C] = [A] + [B]	**GSC-1 SCI Procured Amount**	*MWh*	**475,000**	**500,000**	**25,000**
[D]	Weighted Price	*$/MWh*	**$ 73.50**	**$ 72.50**	$ (1.00)
[E] = [C] x [D]	GSC-1 SCI Procurement Cost	*$*	$ 34,912,500	$ 36,250,000	$ 1,337,500
[F]	AEC	*$*	$ 1,000,000	$ 1,000,000	$ -
[G] = [E] + [F]	**Procurement + AEC Cost**	*$*	**$ 35,912,500**	**$ 37,250,000**	**$ 1,337,500**
[H]	Customer Load (w/out Losses)	*MWh*	425,000	425,000	-
[I] = [G] / ([H] x 1000)	**Rate**	*$/kWh*	**$ 0.08450**	**$ 0.08765**	**$ 0.00315**
	GSC-2				
[J]	Gross Load (w/ Losses)	*MWh*	250,000	250,000	0
[K]	Net Metering	*MWh*	0	(25,000)	(25,000)
[L] = [J] + [K]	**GSC-2 Procured Amount**	*MWh*	**250,000**	**225,000**	**(25,000)**
[M]	Capacity Price	*$/MWh*	$ 30.00	$ 30.00	$ -
[N]	Energy Price	*$/MWh*	$ 40.00	$ 40.00	$ -
[O] = L x ([M] + [N])	GSC-2 Procurement Cost	*$*	$ 17,500,000	$ 15,750,000	$ (1,750,000)
[P]	AEC	*$*	$ 500,000	$ 500,000	$ -
[Q] = [O] + [P]	**Procurement + AEC Cost**	*$*	**$ 18,000,000**	**$ 16,250,000**	**$ (1,750,000)**
[R]	Customer Load (w/out Losses)	*MWh*	215,000	215,000	-
[S] = [Q] / ([R] x 1000)	**Rate**	*$/kWh*	**$ 0.08372**	**$ 0.07558**	**$ (0.00814)**
	Customer-Generator Compensation				
[T] = [B] + [K]	Net Metering	*MWh*	25,000	25,000	0
[U] = [D] or ([M] + [N])	Compensation Rate	*$*	$ 73.50	$ 70.00	$ (3.50)
[V] = [B] x [U]	E Factor Reconciliation - GSC-1	*$*	$ 1,837,500	$ -	$ (1,837,500)
[W] = [K] x [U]	E Factor Reconciliation - GSC-2	*$*	$ -	$ 1,750,000	$ 1,750,000
	Total				
[X] = [G] + [V]	Effective GSC-1 Cost	*$*	$ 37,750,000	$ 37,250,000	$ (500,000)
[Y] = [X] / ([H] x 1000)	*Effective GSC-1 Rate*	*$/kWh*	*$ 0.08882*	*$ 0.08765*	*$ (0.00117)*
[Z] = [Q] + [W]	Effective GSC-2 Cost	*$*	$ 18,000,000	$ 18,000,000	$ -
[AA] = [Z] / ([R] x 1000)	*Effective GSC-2 Rate*	*$/kWh*	*$ 0.08372*	*$ 0.08372*	*$ -*
[AB] = [Y] + [AA]	**Effective GSC-1 + GSC-2 Cost**	*$*	**$ 55,750,000**	**$ 55,250,000**	**$ (500,000)**

MAXIMUM REGISTERED PEAK LOAD (MRPL) - NUMERICAL EXAMPLE (CONT'D)

[A]	Gross Load (w/ Losses)	*MWh*	500,000	
[B]	Customer Load (w/out Losses)	*MWh*	425,000	
[C]	Current BTM Generation Nameplate Capacity	*MW*	15	
[D]	Pipeline BTM Generation Nameplate Capacity	*MW*	8	
[E]	DSP Supplier Cost	*$/MWh*	**$ 72.50**	*assumed marginal cost is flat (not increasing)*

			[1] Scenario 1 PPL	[2] Scenario 2 Low Shortage Risk	[3] Scenario 3 Med Shortage Risk	[4] Scenario 4 High Shortage Risk	[5] Average
[F]	Scenario Likelihood	%	10%	30%	40%	20%	100%
[G]	Completion Rate	%	50%	30%	30%	15%	29%
[H]	Capacity Factor	%	30%	30%	20%	20%	24%
[I] = [A]	Gross Load (w/ Losses)	*MWh*	500,000	500,000	500,000	500,000	500,000
[J] = (([C] x [H]) + ([D] x [G]x[H])) x 4380	Net Metering	*MWh*	24,966	22,864	15,242	14,191	18,291
[K] = [I] - [J]	Net Energy Demand	*MWh*	**475,034**	477,136	484,758	485,809	481,709
[L] = [K-1]	**GSC-1 SCI Procured Amount**	*MWh*	**475,034**	**475,034**	**475,034**	**475,034**	**475,034**
[M] = [K] - [L]	Shortage	*MWh*	-	2,102	9,724	10,775	6,675
[N] = [E-1] x [L]	DSP Supplier Cost - GSC-1 SCI Procured Amount	*$*	$ 34,439,965	$ 34,439,965	$ 34,439,965	$ 34,439,965	$ 34,439,965
[O] = [E-1] x [M]	DSP Supplier Cost - Shortage Cost	*$*	$ -	$ 152,424	$ 704,961	$ 781,173	$ 483,946
[P] = [N] + [O]	**Total Cost**	*$*	**$ 34,439,965**	**$ 34,592,389**	**$ 35,144,926**	**$ 35,221,138**	**$ 34,923,911**
[Q] = [P] / [L]	**DSP Supplier Bid - Rate Requirement**	*$/MWh*	**$ 72.50**	**$ 72.82**	**$ 73.98**	**$ 74.14**	**$ 73.52**
[R] = [L] x [Q]	GSC-1 SCI Procurement Cost	*$*					**$ 34,923,911**
[S]	*Check*	*$*					*$ 34,912,500*

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2025-3057164
PPL Electric Utilities Corporation	:	

VERIFICATION

I, Zachary F. Teti, hereby state that the facts above set forth in my Rebuttal Testimony, OCA St. 6R, are true and correct to the best of my knowledge, information, belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: January 23, 2026

Signature: /s/ Zachary F. Teti
Zachary F. Teti

Address: 555 Walnut St.,
Harrisburg, PA 17101

OCA STATEMENT 6SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	
PPL Electric Utilities Corporation	**)**	**Docket No. R-2025-3057164**
	)	
	)	

SURREBUTTAL TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

February 9, 2026

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OCA Exhibit ZT-1SR – Response to the Set XXIX Data Requests of the OCA

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND BUSINESS DESCRIPTION.

A. My name is Zach Teti. I am a Senior Regulatory Analyst at the Pennsylvania Office of Consumer Advocate ("OCA"). My office is located at 555 Walnut St, Harrisburg, PA 17101. The OCA is a state agency that represents the interests of Pennsylvania utility consumers before the Pennsylvania Public Utility Commission ("PUC"), federal regulatory agencies, and state and federal courts. The OCA was created by the Pennsylvania General Assembly in 1976 and is an independent office within the Office of Attorney General.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement 6 on December 22, 2025. My rebuttal testimony was submitted as OCA Statement 6R on January 23, 2025.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I am responding to the Rebuttal Testimony of Kevin M. Lucas, Joint Solar Advocates Statement ("JSA") Statement No. 1R and Andrew Castanaro, PPL Electric Utilities Corporation ("PPL" or "Company") Statement No. 15-R. My Surrebuttal Testimony addresses certain elements of the proposed Maximum Registered Peak Load ("MRPL") methodology submitted to take effect in 2026. In the Rebuttal Testimony of Mr. Lucas, he chose to highlight (1) moments where I found information to be incomplete or unclear throughout this regulatory proceeding and (2) that I did not conduct certain empirical analyses to support claims by the Company. In my Rebuttal Testimony, I note that "to understand the detailed complexities of the Company's

DSP procurement and billing required a lengthy review of disjointed testimony and interrogatory responses." Then, I said, "in this regulatory proceeding and prior to any accepted tariff change, clarity should be reached on this subject." In PPL Response to OCA Interrogatory XXIX and Statement No. 15R, I believe Mr. Castano has provided helpful comments that improves the record on: (1) the complexities of the default service plan ("DSP") conducted by the Company and (2) the importance of efficient procurement of the Company's DSP passed through to customers via Generation Supply Charge-1 ("GSC-1") and GSC-2.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. Section I is an introduction. Section II provides an update to areas where Mr. Lucas noted that I believed "PPL had not offered clear responses to discovery or had offered responses that surprised [me]."[1] Section III, the final section of my Surrebuttal Testimony, discusses my use of theory rather than empirical analysis due to data constraints or opinion that theory is adequate.

Q. ARE YOU ATTACHING EXHIBITS TO YOUR REBUTTAL TESTIMONY?

A. Yes. PPL Response to OCA Interrogatory XXIX is attached as Exhibit ZT-1SR.

Q. ARE YOU RECOMMENDING THAT THE COMPANY'S PROPOSED MRPL METHODOLOGY BE APPROVED BY THE PUC?

A. Yes, I am. My review of other parties' direct and rebuttal testimony in this proceeding has not changed my recommendation.

[1] JSA Statement No. 1R, p. 2

II. UPDATE TO TOPICS THAT MERITED CLEARER OR EXPANDED RESPONSES FROM PPL

Q. PLEASE PROVIDE THE LIST PROVIDED BY MR. LUCAS.

A. The list, inclusive of my addition of subject headers, is as follows:

1) **Procurement Efficiency:** When told by the Company that the MRPL proposal would not impact the Default Service Plan ("DSP") procurement efficiency, Mr. Teti noted "Admittedly, I expect there would be an improvement to energy procurement with this change; this is something that I believe PPL should further explore in this proceeding."
2) **Value Proposition:** Regarding the "value proposition" between the benefits of load reductions and its effect on PJM costs and how to compensate customer-generators for this reduction, Mr. Teti opined "In this regulatory proceeding, I recommend that PPL demonstrate further clarity on this value proposition."
3) **Procurement Process:** After asking several rounds of discovery to the Company about the interaction of customer-generators and the DSP procurement process, clarity was still not forthcoming: "After reviewing these responses, I might have more questions to better understand this process."
4) **Capacity Cost Recovery:** When addressing the core issue of the MRPL – the reclassification of customers from GSC-1 to GSC-2, Mr. Teti wrote "It is my expectation that the supply charge designation would not impact the level at which PJM costs are assigned to PPL. But after reviewing PPL responses to OCA Interrogatory Set XXVII, I would like to better understand the process by which capacity costs and compensation to customer-generators are recovered by PPL customers."[2]

Q. HAS THE COMPANY FURTHER EXPANDED ON ITEM NO. 1 REGARDING PROCUREMENT EFFICIENCY?

A. Yes.

Q. PLEASE INCLUDE WHAT MR. CASTANARO PRESENTED.

A. In PPL Statement No. 15-R, Mr. Castanaro agreed "that the MRPL will temper risk premiums for switching and volumetric risk, but it will not completely eliminate

[2] JSA Statement No. 1R, p. 2-3

them. There will still be uncertainty related to these factors, given the ability of all customers to leave and return to default service."[3]

Q. IS THIS AN ADEQUATE ACKNOWLEDGEMENT?

A. Yes. I agree with Mr. Castanaro's assertion.

Q. HAS THE COMPANY EXPANDED ON ITEM NO. 2 REGARDING THE VALUE PROPOSITION?

A. Yes. Mr. Castanaro outlined his views on (1) load reduction and PJM costs, (2) retail rate components, and (3) direct wholesale participation.[4]

Q. DO YOU AGREE WITH PPL WITNESS CASTANARO'S STATEMENT ON THIS VALUE PROPOSITION?

A. Yes. I also appreciate the extension of customer-generator opportunities including: (1) a bilateral power purchase agreement upon obtaining a Wholesale Market Participation Agreement ("WMPA") or (2) shopping for an Electric Generation Supplier if there is an advantageous rate.

Q. HAS THE COMPANY EXPANDED ON ITEM NO. 3 REGARDING THE INTERACTION OF CUSTOMER-GENERATORS AND THE DSP PROCUREMENT PROCESS?

A. Yes. I submitted OCA Interrogatory XXIX to the Company and their responses are attached as Exhibit ZT-1SR. In my Rebuttal Testimony, I then created a numerical example as these cash flow arrangements were a topic in a few interrogatories and testimony discussions submitted by the Parties.

[3] PPL Statement No. 15-R, p. 3
[4] *Id*, p. 4

Q. HAS THE COMPANY EXPANDED ON ITEM NO. 4 REGARDING CAPACITY COST RECOVERY?

A. Yes, however, if the MRPL proposal were approved and the negative PLC concept were also pursued, I believe more details would need to be straightened out which I expanded on in my Rebuttal Testimony. [5, 6]

III. THOUGHTS ON TOPICS WHERE MR. LUCAS IDENTIFIED CONCERNS THAT I DID NOT PERFORM AN INDEPENDENT EMPIRICAL ANALYSIS

Q. PLEASE PROVIDE THE LIST PROVIDED BY MR. LUCAS.

A. The list, inclusive of my addition of subject headers, is as follows:

1) **Stress:** While he testified that "This current practice fails to reflect the stress that behind-the-meter generation puts on PPL Electric's distribution system," Mr. Teti later admitted that he "did not conduct, or review studies, analyses, reports, or data related to PPL's distribution system when reiterating the remarks of Mr. Castanaro."
2) **Subsidization:** "Additionally, the current classification results in non-net metering Small C&I default service customers disproportionately subsidizing the annual cash-outs of customer generators that are, effectively, merchant Generators," Mr. Teti was simply "restating this remark made by PPL witness Castanaro" but "did not conduct, or review studies, analyses, reports, or data 1 when restating the remarks of Mr. Castanaro."
3) **Cost-Shift Analysis:** In discovery, Mr. Teti noted "As I stated in Footnote 13 of my Direct Testimony, JSA Interrogatory Set I-26 was helpful in better understanding this analysis, but I did not prepare an analysis or review additional documents to independently confirm Mr. Castanaro's estimate." Notably, the responses in JSA Interrogatory Set I-26, among others, informed the detailed analysis I performed in my direct testimony that found substantial methodological errors and poor assumptions in the Company's cost-shift analysis.
4) **Supplier Risk Premium:** "The OCA is not permitted to see bid details following the completion of default service procurement auctions or the constituent components of each individual bidder's bid to provide default supply in the auction and, as a result, the actual quantification of costs and benefits is not possible." In other words, because the OCA is prohibited

[5] Direct Testimony of Justin R. Barnes, p. 46
[6] Direct Testimony of Zach Teti, p. 11

> from seeing these details, Mr. Teti's speculation on the matter cannot be supported.[7]

Q. PLEASE DISCUSS ITEM NO. 1 REGARDING STRESS.

A. I generally understand that utilities employ engineers for tasks such as distributed energy resource interconnection analysis, asset condition monitoring, and distribution system operations which factors output from distributed energy resources. So, I find this qualitative characterization made by the Company to be perceivable as these tasks are their tasks. In response to Interrogatory OCA-I-2 focused on behind-the-meter generation stress on the distribution system, I also noted that I "review[ed] the report on Central Maine Power's Integrated Grid Plan which was published in December 2025 which discusses the issue." An applicable finding from this report:

> The rapid proliferation of [distributed energy resources] DERs, particularly distributed solar, is transforming grid utilization and increasing operational complexity. Bidirectional power flows are challenging traditional voltage control and fault isolation practices, requiring a shift from reactive to proactive, data driven operations. CMP plans to invest in an enhanced EMS and deploy an ADMS platform that incorporates Volt-VAR Optimization (VVO), Fault Location, Isolation and Service Restoration (FLISR), power flow, and Distributed Energy Resource Management System (DERMS) functions.[8]

Q. DID YOU DISCUSS NO. 2 REGARDING SUBSIDIZATION IN REBUTTAL TESTIMONY?

A. Yes, I did discuss this further and do not have anything to add to my response.[9]

Q. DID YOU DISCUSS NO. 3 REGARDING THE COST-SHIFT ANALYSIS IN REBUTTAL TESTIMONY?

A. Yes, I did discuss this further and do not have anything to add to my response.[10]

[7] JSA Statement No. 1R, p. 3-5

[8] Central Maine Power's Integrated Grid Plan, p. 36

[9] Rebuttal Testimony of Zach Teti, p. 4-5

[10] *Id*, p. 5-6

Q. PLEASE DISCUSS NO. 4 REGARDING SUPPLIER RISK PREMIUM?

A. In Rebuttal Testimony, I offered a numerical example to illustrate supplier volumetric uncertainty based on a variety of possible scenarios. Fundamentally, this uncertainty is likely to lead to the use of a risk premium, which raises costs.[11] Again, in PPL Statement No. 15-R, Mr. Castanaro agreed "that the MRPL will temper risk premiums for switching and volumetric risk, but it will not completely eliminate them. There will still be uncertainty related to these factors, given the ability of all customers to leave and return to default service."[12]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. To be clear, I am supportive of DER proliferation and believe this infrastructure should be compensated "appropriately" (an expression Mr. Castanaro introduced in PPL Statement No. 15-R). I do not believe that changing the manner in which net-metered customer-generators are classified for default service supply procurement as proposed by PPL in this proceeding would fail to appropriately compensate those customer-generators, which may be assigned a different default service rate classification.

[11] OCA Exh. ZT-2R.

[12] PPL Statement No. 15-R, p. 3

OCA STATEMENT 6SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

EXHIBITS TO THE

SURREBUTTAL TESTIMONY

OF

ZACH TETI

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

February 9, 2026

PPL Electric Utilities Corporation
Response to the Set XXIX Data Requests of the
Office of Consumer Advocate (OCA)
Dated December 29, 2025
Docket No. R-2025-3057164

OCA XXIX-1

Please expand on cash flow as it relates to compensation to customer-generators for excess generation.

a. How does PPL pay for the excess generation in the annual cash-out? That is, from where is the cash derived? Does PPL use working capital to do this or is this cash-out funded by the default service plan (DSP) suppliers from the applicable DSP?
b. Does "backing out" net metering quantity in GSC-1 energy procurement make under-collection of revenue in a DSP cycle more likely? If DSP suppliers are funding the annual cash-out (Question 1) and the quantity in GSC-1 energy procurement reflects backed out net metering (Answer to OCA XXVII-4), will DSP suppliers need to increase their rates to ensure they are made financially whole?
c. Or, when PPL recovers this under-collection through an E-Factor reconciling item in a subsequent DSP cycle, does this revenue go back to DSP suppliers (if they are funding the cash-out per Question 1)?

PPL Electric Response

a. The actual expense incurred associated with cashing out net metering customers for excess generation is incurred by PPL Electric and included in the reconciliation calculation of the Transmission Service Charge (TSC) for the respective customer classes and the reconciliation calculation of the Generation Supply Charge-1 (GSC-1) charge for Residential and Small C&I customers and the Generation Supply Charge-2 (GSC-2) for Large C&I customers. The reconciliation amount is then included in the subsequent TSC, GSC-1, and GSC-2 rate filings in the Net Over(Under) Collection Amount value.

The TSC, GSC-1, and GSC-2 are charged to only default service customers.

Because these are rider-related expenses, they are not included in the Company's cash working capital calculation in this instant rate case.

From a strictly cash perspective, PPL Electric pays the customer-generator accounts for the expense on its books and later recovers the cash from default service customers through the ratemaking method described above. PPL Electric recovers the cash when customers pay their monthly bills.

b. To clarify, Default Service Suppliers are not funding the net metering cash out. This expense is incurred by PPL Electric and recovered by PPL Electric through a portion of dollars received by PPL Electric through the TSC, GSC-1, and GSC-2 rates.

Assuming the question is referring to the Company's practice of removing an estimated amount of net metering generation from the default service load used to calculate the GSC-1 rate as described in the response to JSA V-9, the Company does not believe that doing so makes an under collection more likely. Rather, the Company makes this adjustment in an effort to make the forecasted default service load used in the rate calculation more reflective of the actual default service load that the Company will experience during the period to minimize the amount of the reconciliation over/under amount. That reconciliation over/under amount is included in subsequent GSC-1 rate filings.

c. See the responses to Part A and B.

OCA XXIX-2	Is the cash flow process outlined in Question 1 similar for both GSC-1 and GSC-2?
PPL Electric Response	Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2025-3057164
PPL Electric Utilities Corporation	:	

VERIFICATION

I, Zachary F. Teti, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. 6SR, are true and correct to the best of my knowledge, information, belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: February 9, 2026

Signature: /s/ Zachary F. Teti
Zachary F. Teti

Address: 555 Walnut St.,
Harrisburg, PA 17101

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3057164
	:	
PPL Electric Utilities Corporation	:	

ADDITIONAL LIST OF EVIDENCE TO BE ADMITTED INTO THE EVIDENTIARY RECORD BY THE OFFICE OF CONSUMER ADVOCATE

The Office of Consumer Advocate (OCA) intends to submit the following evidence into the evidentiary record in the above captioned proceedings at the telephonic hearing scheduled for March 9, 2026.

OCA Direct Testimony

OCA Statement 6: Direct Testimony of Zach Teti with Verification, including:
- Exhibit ZT-1 and Exhibit ZT-2

OCA Rebuttal Testimony

OCA Statement 6R: Rebuttal Testimony of Zach Teti with Verification, including:
- Exhibit ZT-1R

OCA Surrebuttal Testimony

OCA Statement 6SR: Surrebuttal Testimony of Zach Teti with Verification, including:
- Exhibit ZT-1SR

OCA Additional Evidence

OCA Hearing Exh. 3: Additional List of Evidence to be Admitted into the Evidentiary Record by the Office of Consumer Advocate.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3057164**
v.	:	
	:	
PPL Electric Utilities Corporation	:	

OFFICE OF SMALL BUSINESS ADVOCATE'S
FURTHER ADMITTED
TESTIMONY AND EXHIBITS

The Office of Small Business Advocate ("OSBA") admitted the enclosed testimony and exhibits, as evidence into the evidentiary record at the Further Evidentiary Hearing, held on March 9, 2026, in the above-captioned proceeding:

- Sur-Rejoinder Testimony of Mark D. Ewen, labelled OSBA Statement No. 1-SRJ, with signed Verification of Mark D. Ewen.

Date: April 7, 2026

COMMONWEALTH OF PENNSYLVANIA

March 2, 2026

The Honorable Christopher P. Pell
Deputy Chief Administrative Law Judge
Pennsylvania Public Utility Commission
Philadelphia District Office
801 Market Street
Philadelphia, PA 19107

The Honorable Barbara Shadie Nause
Administrative Law Judge
Pennsylvania Public Utility Commission
Philadelphia District Office
801 Market Street
Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation / Docket No. R-2025-3057164

Dear Judge Pell and Judge Shadie Nause:

Enclosed please find the Sur-Rejoinder Testimony of Mark D. Ewen, labelled OSBA Statement No. 1-SRJ, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-referenced proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Attorney
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: PA PUC Secretary Matthew L. Homsher (Cover Letter & Certificate of Service Only)
Mark D. Ewen
Maksim Malukoff
Robert D. Knecht
Parties of Record

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3057164**
v.	:	
	:	
PPL Electric Utilities Corporation	:	

SUR-REJOINDER TESTIMONY

of

MARK D. EWEN

on behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Net Metering
Updated PPL Proposal

Date Served: March 2, 2026

Date Submitted for the Record: _____

SUR-REJOINDER TESTIMONY OF MARK D. EWEN

I. Introduction

Q. Mr. Ewen, please state your name and briefly describe your qualifications.

A. My name is Mark D. Ewen. I submitted testimony and associated exhibits on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA") earlier in these proceedings and my qualifications were presented therein.

Q. What is the purpose of this sur-rejoinder testimony?

A. This testimony responds to the following witnesses/topics:

- Net metering policy and PPL Electric's proposed GSC-1 and GSC-2 reclassification framework.
- Corrections to PPL Witness Castanaro's excess generation and Price to Compare projections.

II. Net Metering

Q. Please explain net metering and outline the Company's proposed change for classifying customers under GSC-1 and GSC-2.

A. I outlined the principles of net metering in detail in my direct testimony. In short, net metering is a policy designed to encourage the adoption of renewable distributed generation by allowing customer-generators to set the kWh billing determinant for all energy charges – generation, transmission, distribution, universal service, and others – on a net basis, reflecting the difference between power delivered to the customer and power shipped back to the distribution system. Generally, credits for generation that exceeds consumption are constrained, as net metering is conceptually based on the idea of the customer meeting its own requirements. In Pennsylvania, however, the legislature allows both (a) net generators to cash out excess generation at the generation Price to Compare ("PTC") and (b) general service customers to install up to 3 megawatts ("MW") of generating capacity regardless of the size of their actual loads.

PPL Electric has two GSC default service classes determined by a 100 kW peak demand

threshold: GSC-1 for Small C&I customers and GSC-2 for Large C&I customers. Under the current structure, customers with significant net metering output but negligible demand remain classified as GSC-1, even when their generation output far exceeds what a typical small commercial customer would produce.

PPL Electric proposes to reclassify default service customers based on "net power flow from or into the Company's distribution or transmission system," reflected in a revised definition of Maximum Registered Peak Load ("MRPL") in the tariff.[1] Under this proposal, any customer or customer-generator that imports or exports more than 100 kW during the 12-month period ending September 30 would be assigned to GSC-2. This change would ensure that large front-of-meter generators are classified according to their true operational footprint rather than their nominal demand from the grid.

Q. Please explain the impacts of the Company's proposal to small business customers.

A. Under the current structure, when large customer-generators export excess power, those purchases are treated as default service supply and charged back to the entire GSC-1 class. Non-generating small business customers – retailers, restaurants, professional offices, and service providers – bear the residual cost of that supply without the ability to benefit from or influence said supply. The Company's proposal to classify customers under GSC-1 and GSC-2 would protect non-generating small business customers in the GSC-1 class from a growing burden to cover costs they do not incur.

PPL Witness Castanaro's corrected analyses quantify the scale of this inequity. Under the 36 percent project cancellation rate scenario, total net metering compensation paid to no-load customer-generators under GSC-1 is projected to increase from approximately $10.8 million in 2025 to approximately $795 million in 2029. The PTC paid by all GSC-1 customers is projected to rise to $0.29980 per kWh by 2030 under that same scenario.[2] These are not abstract concerns. A PTC approaching $0.30 per kWh would represent an extraordinary burden on small businesses.

PPL Witness Castanaro also identifies the downward spiral facing the GSC-1 class: as

[1] Docket P-2024-3049343.

[2] PPL Electric Statement No. 15-RJ.

rates rise, non-generating customers would seek alternative suppliers, leaving fewer customers to absorb the costs, which would drive the PTC even higher:[3]

> I recognize that these PTC rate increases are substantial, and if they came to fruition, would likely cause catastrophic impacts in the retail electric market for Small C&I customers. Non-customer-generators under Rate GSC-1 would be paying exorbitant rates and likely forced to seek an alternative supplier. Such an outcome would create a significant switching risk from a default service supply procurement standpoint and lead to fewer customers on Rate GSC-1 being able to absorb these costs in the PTC rate, in turn leading to the rate increasing even further. Compounding the harm, I expect that EGSs would increase their rate offerings to customers based on the increased level of the PTC, leaving non-customer generators in the Small C&I class likely without an option to avoid these cost increases.

The Company's proposal interrupts this dynamic by appropriately classifying and compensating large customer-generators within frameworks appropriate to their scale and market sophistication, as merchant generators. OSBA has supported a similar rate structure change in the recent UGI Utilities, Inc. Default Service Provider proceeding.[4]

III. Updated PPL Proposal

Q. What corrections did PPL Witness Andrew Castanaro make to his previous net metering calculations?

A. Witness Castanaro identified and corrected two material errors in his prior analyses.[5]

First, his original Exhibit AC-1 used a 0 percent project cancellation rate instead of the correct 36 percent rate reflecting PPL Electric's actual experience with interconnection queue cancellations. This error caused the excess generation, PTC impact, and net metering compensation figures to be overstated. As a result, the average monthly bill impact of $174.01 to Small C&I customers cited in his rebuttal testimony was corrected downward to $97.42.

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[3] *Id.*

[4] Docket P-2024-3049343.

[5] PPL Electric Statement No. 15-RJ.

Second, and more significantly, the original analyses failed to include no-load customer-generator projects associated with distribution Rate LP-4 that fall under default service Rate GSC-1. Only GS-3 and GSC-1 projects were included, causing a substantial understatement of total excess generation in the interconnection queue.

When the LP-4/GSC-1 projects are incorporated at the corrected 36 percent cancellation rate, total projected excess generation in 2029 increases from approximately 1.43 TWh to approximately 2.62 billion TWh. The projected PTC increases from $0.20474 per kWh to $0.29980 per kWh, and total net metering compensation paid to no-load customer-generators increases from approximately $304 million to approximately $795 million in 2029.

Witness Castanaro also prepared updated analyses using a lower 17.3 percent capacity factor and incorporating procurement offsets reflecting how excess generation reduces default service supply requirements. Even with those downward adjustments, the updated analyses continue to show substantial PTC increases and confirm the need for the MRPL proposal.

Q. What was your position on the Company's proposed method of classifying customers under GSC-1 and GSC-2, prior to Mr. Castanaro's corrections?

A. Prior to Mr. Castanaro's corrections, I supported the Company's proposed change for reasons I explained in my direct testimony. In doing so I acknowledge that customer-generators should be fairly compensated for the energy they supply to the Company's distribution system. My position remains that reclassifying large customer-generators under GSC-2 would offer these customers fair compensation without unduly burdening non-customer-generators under GSC-1. The issue that remains is whether PPL Electric's proposed changes accurately classify customers for default service assignment, which should be based primarily on the load characteristics of customers (i.e., peak demand and supply) and how best to secure default service for similar customers, rather than on *a priori* judgements about the price at which customer-generators should be compensated for their generation.

The current classification structure results in non-generating small business customers in

GSC-1 subsidizing large front-of-meter customer-generators whose scale and market behavior more closely resemble merchant generators than small commercial customers. The 100 kW threshold is designed to distinguish between small behind-the-meter customer-generators that still draw energy from the grid and larger front-of-meter installations that are effectively no-load net metering facilities. The latter operate without the risks borne by GSC-1 default service suppliers, who must procure energy to meet the Small C&I load shape, secure firm generation capacity, manage load fluctuation risk, and bear all operating costs of power procurement – yet large customer-generators receive the retail PTC . This asymmetry is inequitable and imposes costs on non-generating small businesses they should not bear.

Q. How did your position change given the recent updates to Mr. Castanaro's calculations?

A. I continue to support the Company's proposed changes; in fact, the argument for the MRPL proposal is *strengthened* by Mr. Castanaro's corrected and updated analyses. The corrections reveal that the cost-shift to non-generating small business customers is substantially larger than the original analyses indicated. The projected PTC increase to nearly $0.30 per kWh by 2029 under the 36 percent cancellation rate scenario – even after incorporating the lower capacity factor and procurement offsets suggested by opposing parties – represents a concrete and quantified harm to the small businesses OSBA represents.

Importantly, Mr. Castanaro's rejoinder testimony also resolves a technically substantive concern raised in opposition to the MRPL proposal. In response to questions about whether GSC-2 excess generation credits include the capacity component of the PTC, the Company stated that it would be willing to incorporate a capacity component into the net metering compensation calculation for GSC-2 customer-generators as part of its compliance retail tariff filing.[6] This commitment directly addresses the compensation gap concern and confirms that classification and compensation are separable issues – precisely the position

[6] *Id.*

OSBA advanced.

Q. Do you agree with Mr. Castanaro that PPL's MRPL proposal should be based on quantitative and operational evidence?

A. I do.

Q. In your opinion, does Mr. Castanaro present sufficient quantitative and operational evidence that non-customer-generating small commercial class customers will be harmed in the absence of the PPL's proposed change?

A. Yes. It is important in reviewing Mr. Castanaro's answers in his rejoinder testimony to distinguish between the two fundamental questions that are conflated by other interveners (e.g., Mr. Castanaro's response to CSC Witness Sharfman). Other interveners are conflating two distinct questions: (a) whether current GSC-1 compensation is fair to customer-generators, and (b) whether reclassification to GSC-2 would produce fair compensation. These are separate inquiries. While Mr. Castanaro does provide ample evidence of harm to non-generating customer classes, the absence of a precise and agreed-upon numerical value does not undermine the ratemaking principle on which PPL's proposal, or OSBA's position, rests.

The relevant guide to analyzing PPL's proposal and exhibits is not in a specific dollar figure, but whether the compensation mechanism accurately reflects the class into which a customer belongs based on its actual load and supply characteristics. Large front-of-meter customer-generators selling 100 kW or more are more accurately characterized as 'merchant generators' than as small commercial customers. As such, my position is that their compensation should be determined within the default service framework applicable to that classification.

Other witnesses argue that the existing GSC-1 structure is Commission-approved and has not been shown to be excessive. This position is irrelevant. Rate cases exist precisely to revisit and revise approved tariff structures when circumstances change or when those structures produce inequitable results. Given the GSC-1 class was designed for small commercial customers with modest loads and a primary relationship with the grid, a customer supplying several MW of generation capacity to the grid with little load is

functionally not a small commercial customer but a generator with a nominal commercial account. Continuing to compensate such customer-generators under a small commercial framework is a question of fairness to all non-generating small business customers who will continue to bear the burden of costs they do not incur.

Q. Does this conclude your sur-rejoinder testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. R-2025-3057164**
v.	:	
	:	
PPL Electric Utilities Corporation	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Sur-Rejoinder Testimony, labelled OSBA Statement No. 1-SRJ, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: February 27, 2026

Mark Ewen

Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket Nos. R-2025-3057164**
v.	:	**C-2025-3057889**
	:	
PPL Electric Utilities Corporation	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Christopher P. Pell
Deputy Chief Administrative Law Judge
Pennsylvania Public Utility Commission
Philadelphia District Office
801 Market Street
Philadelphia, PA 19107
cpell@pa.gov

The Honorable Barbara Shadie Nause
Administrative Law Judge
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2025-3057164
v.	:	
	:	
PPL Electric Utilities Corporation	:	
	:	

Solar Energy Industries Association and the Coalition for Community Solar Access, the "Joint Solar Advocates"

Statement No. 1

Direct Testimony of
Kevin M. Lucas

Topics Addressed: Customer Generators in Pennsylvania, PPL's Maximum Registered Peak Load Proposal

Date: December 22, 2025

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Appendix A - Glossary of Terms

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

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

Q2. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.

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

As Vice President of Policy Analysis, I have developed testimony in rate cases on rate design and cost allocation; in integrated resource plans ("IRPs") on resource selection and portfolio analysis; worked on net energy metering, virtual power plant, and distributed generation compensation mechanisms; and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy ("Alliance") from 2016 to 2017, a Washington DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy

efficiency products and service providers that were seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

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

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

Q3. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION?

A3. Yes. I testified in the Citizens' Electric Company of Lewisburg's most recent rate case on behalf of Kelly Road Solar, LLC, Lancaster Avenue Solar, LLC, and Twilight Renewables, LLC (collectively, the "Solar Projects").[1]

Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?

[1] Direct Testimony of Kevin Lucas On Behalf Of Kelly Road Solar, LLC, Lancaster Avenue Solar, LLC, and Twilight Renewables, LLC, July 15, 2025, Docket No. R-2025-3054394.

A4. Yes. I have submitted testimony in rate cases, IRPs, utility merger proceedings, and renewable portfolio and energy efficiency resource standards before the Arizona Corporation Commission, the Colorado Public Utilities Commission, the Georgia Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Michigan Public Service Commission, the Public Utility Commission of Nevada, the North Carolina Utilities Commission, the Public Service Commission of South Carolina, the Public Utility Commission of Texas, and the Virginia State Corporation Commission. My complete Curriculum Vitae is attached to my testimony.[2]

Q5. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A5. My testimony is provided on behalf of SEIA and the Coalition for Community Access ("CCSA"), jointly called the Joint Solar Advocates ("JSA") in this proceeding. CCSA is a 501(c)(6) nonprofit trade organization focused on supporting the community solar industry through legislative and regulatory efforts. Net metering by customer-generators can be an element of community solar. CCSA's mission is to empower every American energy consumer with the option to choose local, clean, and affordable community solar. CCSA works with customers, utilities, local stakeholders, and policymakers to develop and implement policies and best practices that ensure community solar programs provide a win for all affected stakeholders, starting with the customer. CCSA has over 120 member companies and is active in virtually all state-level community solar markets, as well as the federal level. CCSA is an active participant in community solar issues pending before the Pennsylvania General Assembly, which includes net metering by customer-generators. Many of CCSA's members develop community-scale solar and

[2]KML Exhibit-1.

solar-plus-storage projects, either with or without subscribers. CCSA advocates for its members' interests in creating and expanding opportunities to develop distributed resources sited close to load that enhance system resilience and reduce overall system costs.

Q6. WHY DID THE JOINT SOLAR ADVOCATES ELECT TO INTERVENE IN THIS PROCEEDING?

A6. CCSA and SEIA members are currently developing distributed generation/alternative energy projects/systems in PPL's Electric ("PPL" or "the Company") service territory and related investment that would be adversely impacted by PPL's proposed changes to the classification and treatment of customer-generators. We intervened and filed a complaint against PPL's rate filing in order to protect the legal and financial interests of our members who, in our view, are being unfairly penalized by PPL for exercising their legal rights to build, operate and engage in electric net metering with PPL for their alternative energy systems.

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A7. The purpose of my testimony, along with my colleague Justin Barnes in JSA Statement No. 2, is to: (i) evaluate and critique PPL's proposal to reclassify net-metered customer-generators and reduce the retail value/Price to Compare[3] by which they are compensated for their excess generation and (ii) offer a reasonable alternative proposal designed to compensate customer-generators based upon a more holistic view of the value they provide to PPL and other customers. Further, our testimony will explain how the adoption of our approach, including grandfathering certain existing and mature in-development customer-generator projects, will: (i) render the GSC-1 customer rate class

[3] Capitalized terms not otherwise defined in this testimony are defined in Appendix A, which is a glossary of terms used in my testimony and in the counterpart testimony of Justin Barnes, JSA Statement No. 2.

financially indifferent to the impact of annual payments by PPL to net-metered customer-generators for excess generation and (ii) not unreasonably increase costs to other PPL customers.

Q8. HOW IS YOUR TESTIMONY ORGANIZED?

A8. I begin by providing an overview of the customer-generator market in Pennsylvania and how energy from these projects interacts with the Company's default service provider ("DSP") contracts. I then address PPL's proposed Maximum Registered Peak Load ("MRPL") proposal that primarily impacts front-of-the-meter distributed generation projects ("FTM DG"), although it can also impact customers installing more traditional behind-the-meter distributed generation projects ("BTM DG"). I discuss its implementation approach and critique several of the Company's justifications for the modifications.

Q9. WHAT ARE YOUR FINDINGS?

A9. I find that customer-generators provide a unique benefit to Pennsylvania, its residents, and its businesses. The FTM DG and BTM DG[4] projects that customer-generators bring online are among the quickest-to-connect sources of new power and energy at a time when PPL and the entire PJM wholesale market are strained under record projected load growth and long lead times for connecting large-scale generation. These projects should be supported, albeit with the appropriate balance of interests between customer-generators and other customers.

[4] See the answer to question 14 below for how I define these terms in my testimony.

PPL's MRPL proposal is poorly supported. Its two primary arguments – that FTM DG projects cause a cost-shift to non-customer-generators and cause "stress" on the distribution grid– do not withstand scrutiny.

I also find that PPL's cost-shift analysis is fundamentally in error because it presents an "all else equal" analysis that results in the purchase of two units of energy to serve one unit of load. The analysis supporting PPL's claimed $300 million cost shift impact on non-customer-generators contains four major errors: (i) an error in the cancellation rate assumptions; (ii) overestimating generation from FTM DG projects; (iii) using constant energy procurement costs even as new FTM DG is added; and (iv) failing to recognize any benefits from FTM DG projects. The results of PPL's analysis are meaningless and inconsistent with how the actual energy procurement process functions.

With respect to "stress", in contrast to the Company's claims in testimony, its discovery responses demonstrate that PPL's distribution grid is already configured to handle potential changes in power flow from FTM DG projects. Further, any power flows that trigger a need for system upgrades will be paid for entirely by customer-generators and not the rest of PPL's customers.

Finally, the Company's MRPL proposal uses a measure of customer demand that is wholly inappropriate for determining the energy supply, GSC-1 or GSC-2, on which a customer must take service. By using the highest 15-minute load at any time over the course of the year instead of one aligned with PJM's peak demand that actually sets energy supply capacity costs for the company, the Company breaks a fundamental ratemaking tenant of rates following cost causation.

Q10. PLEASE SUMMARIZE YOUR RECOMMENDATIONS

A10. I recommend that the Pennsylvania Public Utility Commission ("PaPUC") reject the MRPL proposal and find that the Company has not sufficiently demonstrated the need for the proposed change in customer-generator compensation. JSA Witness Justin Barnes, JSA Statement No. 2, testifies on how to best balance the interests of customer-generators and other customers, and his recommendations can be implemented under PPL's current customer classification approach used to determine on which energy supply tariff a customer takes service.

II. SETTING THE STAGE – THE CUSTOMER-GENERATOR LANDSCAPE

Q11. WHAT IS A CUSTOMER-GENERATOR?

A11. A customer-generator is retail electric customer who owns or operates a net metered distributed generation ("DG") system that is up to 50 kilowatts ("kW") for residential customers and up to 3 megawatts ("MW") for non-residential customers.[5] Net-metered systems are powered by "alternative energy sources", which include solar, wind, geothermal, and certain types of hydropower and biomass.[6] The vast majority of PPL's net-metered systems are solar. At the end of 2024, the U.S. Energy Information Administration reported that of the 28,983 net-metered customers in PPL's territory, only 170 used energy sources other than solar.[7] For that reason, I will assume for the purposes of this testimony that customer-generators are operating photovoltaic ("PV")-based net energy metered ("NEM") systems, although they are not the only resource that can or has qualified for NEM on the Company's grid.

[5] § 75.1. A customer-generator may also operate projects between 3 MW and 5 MW subject to certain operational criteria.
[6] *Id.*
[7] Energy Information Administration, Form 861m, Net Metering 2024.

Q12. IS THE CONCEPT OF A CUSTOMER-GENERATOR UNIQUE TO PENNSYLVANIA?

A12. No, it is not. Electric utility customers in every state are allowed to install behind the meter[8] ("BTM") generation systems to offset a portion of their electricity usage. While the laws and regulations about how these systems are compensated for their power vary from state to state, there are residential and non-residential customer-generators in every state.[9]

Q13. WHAT HAS LED TO THE DEVELOPMENT OF CUSTOMER-GENERATORS IN PENNSYLVANIA?

A13. The Alternative Energy Portfolio Standards Act ("AEPS Act") was signed into law in 2004 and requires Electric Distribution Companies ("EDCs") like PPL to include electricity from alternative energy sources in the generation they sell to Pennsylvania default supply customers. The PaPUC has implemented the AEPS Act in both orders and regulations.[10]

The AEPS Act established and defined the key stakeholders in the-then nascent alternative energy industry in Pennsylvania. The AEPS Act defines "alternative energy" and provides the minimum amounts of alternative energy that must be included within the electricity supply sold by EDCs. The AEPS Act also defines "net metering" by "customer-generators." Net metering is the measured difference between "the electricity supplied by an electric utility and the electricity generated by a customer-generator when any portion of the electricity generated by the alternative energy generating system is

[8] As I discuss in greater detail in the response to Question 14 below, behind the meter systems refer generally to electric generation and storage systems (such as solar and battery storage) that are connected to a utility's distribution system on the customer's side of the utility's electric meter. Energy that a customer facility receives from behind-the-meter solutions bypasses the utility's electric meter, hence "behind the meter."
[9] Energy Information Administration, Form 861m, Net Metering 2024.
[10] *E.g., Implementation of the Alternative Energy Portfolio Standards Act of 2004*, Final Rulemaking Order, Docket No. L-00060180 (Order entered September 29, 2008).

used to offset part or all of the customer-generator's requirements for electricity."[11] Customer-generators are "nonutility owners or operators of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service or not larger than 3,000 kilowatts at other customer service locations…".[12] The AEPS Act laid the groundwork for customer-generators to develop alternative energy systems and provide the electric generation output from those facilities back to EDCs via net metering. The key takeaways are that (i) customer-generators have the right to sell excess energy to EDCs at its full retail value and/or use it to offset any of their own electricity requirements/usage and (ii) the promotion of customer-generators is part of Pennsylvania's energy policy.

Q14. WHAT ARE THE TYPICAL CONFIGURATIONS FOR NEM SYSTEMS?

A14. In Pennsylvania, NEM systems come in two broad categories, which I am denoting as BTM DG or FTM DG. BTM DG is typically installed on the customer side of the utility meter at a site that has more than *de minimis* on-site load. These may be rooftop systems at a residence or business, or a ground mount facility on the campus of a larger commercial building. Energy from a BTM DG system will first flow to serve the customer's on-site load, and any excess beyond that demand will flow through the meter to the Company's grid.

I use the term FTM DG for projects that are typically installed with minimal or *de minimis* on-site load. These are projects that feed the bulk of their power directly into the Company's distribution grid. PPL uses the term "no load customer-generators" for these

[11] 73 P.S. § 1648.2.
[12] *Id*.

projects.[13] Both FTM DG and BTM DG systems can operate under the Pennsylvania NEM framework. Both follow the same calculation methodology to determine what energy is consumed on-site and what is exported, with the distinction that BTM DG systems have a relatively even balance between energy consumed on-site and energy exported to the grid, while FTM DG systems export the vast majority of their generation to an EDC.

Q15. IS THERE ANY LIMITATION ON THE SIZE OF ALTERNATIVE ENERGY SYSTEMS THAT CAN ENGAGE IN NET METERING WITH AN EDC?

A15. Yes. The AEPS Act generally encourages the development of these alternative energy systems up to 50 kW for residential customers and 3 MW for non-residential customers.

Q16. IS THERE ANY LIMITATION ON THE AMOUNT OF EXCESS ENERGY AN ALTERNATIVE ENERGY SYSTEM CAN DELIVER TO AN EDC VIA NET METERING SO LONG AS THE SIZE OF THE SYSTEM DOES NOT EXCEED THE LIMIT SPECIFIED IN THE AEPS ACT?

A16. No. I should also note that the PaPUC has attempted in the past to limit the amount of excess electricity production that can be delivered to EDCs from alternative energy systems via net metering and the Pennsylvania courts have struck down those attempts.

Q17. WHAT IS THE RELATIONSHIP BETWEEN A CUSTOMER-GENERATOR AND NEM?

A17. In Pennsylvania, a customer-generator with an eligible alternative energy system is able to participate in NEM. If the system produces less energy over the course of a month than the customer-generator consumes, the customer-generator pays for the net usage at their full retail rate. When the system produces more energy over the course of a month than the customer-generator consumes, the excess generation is carried over in kWh to

[13] PPL Statement No. 15, p. 7.

the next bill where it is credited against the next month's energy consumption.[14] Any excess generation credits are carried forward for up to a year to be used against future energy consumption, but if any credits are left at the end of the year, they are "cashed out" at the customer's price to compare ("PTC") rate.[15]

For BTM DG systems, the balance of generation from the PV system and the consumption from a customer's usage will determine the credits on a monthly basis. For a customer who has a PV system sized to produce as much energy as they consume over the course of the year, there will be months in the spring and fall where excess generation credits are likely to be produced, and periods in the summer and winter when these excess generation credits are consumed.

Figure 1 below shows the monthly generation and consumption of the average residential customer in PPL's territory for 2024. This customer consumed an average 850 kWh of electricity per month and would require a roughly 8 kW_{DC} PV system based on the average sunlight of PPL's territory to fully offset this amount over the course of a year.[16] In months when the orange bar is larger than the blue bar, the customer-generator would accrue excess generation credits. In months when the blue bar is larger than the orange bar, the customer-generator would consume the credits.

[14] § 75.13(d).
[15] § 75.13(e).
[16] Consumption data form EIA Form 860M for 2024 for the residential class. PVWatts data from Bethlehem PA was used as it was close to the PPL-wide solar generation average.

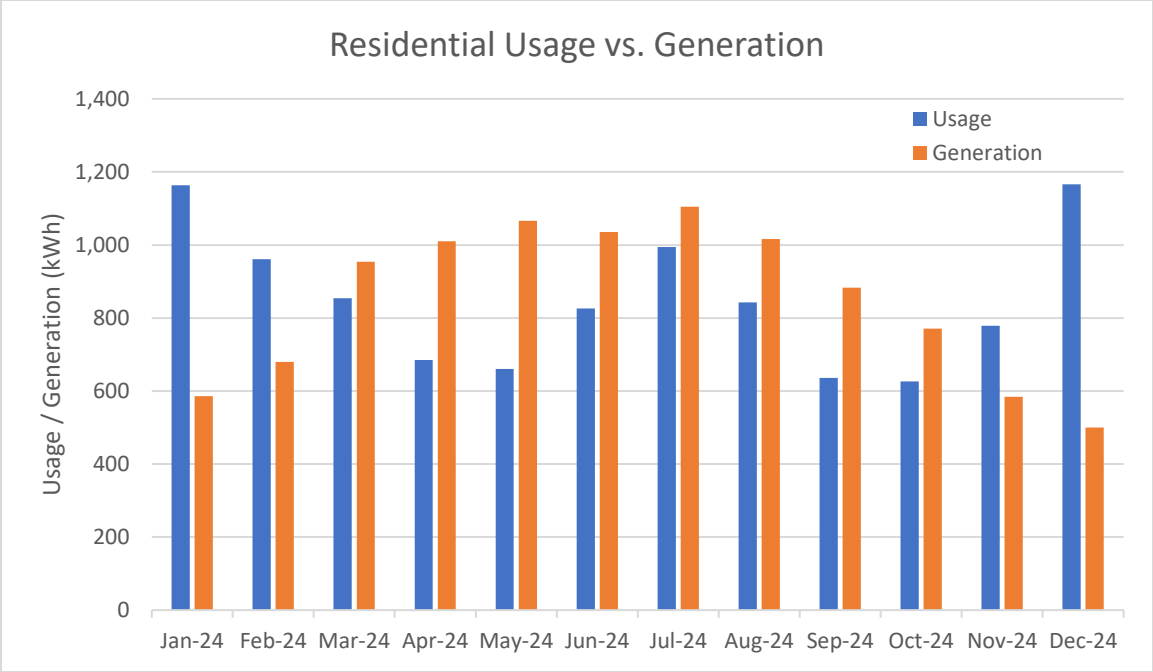

Figure 1 - Residential Usage vs. Generation

Q18. WHEN DOES THE "NEM YEAR" BEGIN AND END IN PPL'S TERRITORY?

A18. The NEM year begins on June 1 and ends on May 31. Based on that cadence, the customer discussed above would build up excess generation credits from June through October, consume those credits in November and December, pay for their net usage in January and February, build up more excess generation credits from March to May, and get paid for those excess credits at the end of May.

Q19. ARE CUSTOMERS WITH FTM DG SYSTEMS TREATED UNDER THE AEPS ACT ANY DIFFERENTLY THAN THOSE WITH BTM DG SYSTEMS?

A19. No. The methodology used to calculate net consumption and excess generation are the same, as is the annual cadence of excess generation accrual and payouts. The main difference is that because FTM DG systems do not have substantial customer load to offset, most of the generation is accumulated each month as excess generation. The total amount that has accrued at the end of May is then cashed out at the PTC rate.

Q20. HOW ARE ALTERNATIVE ENERGY SYSTEM CUSTOMER-GENERATORS ENGAGING IN NET METERING WITH EDCS COMPENSATED FOR EXCESS GENERATION?

A20. The AEPS Act specifically addresses how customer-generators are to be compensated for their excess generation: "[e]xcess generation from net-metered customer-generators shall receive *full retail value* for all energy produced on an annual basis."[17] (emphasis added). This statutory directive has been further addressed by the PaPUC in its AEPS Act-related regulations in Chapter 75 of 52 Pa. Code.[18]

52 Pa. Code §75.13 addresses how customer-generators that are customers of the EDC are to be credited monthly and paid annually for any excess electricity they produce from their alternative energy systems. Customer-generators receive payment/credit from EDCs for their monthly energy production that offsets their monthly purchases as a customer at the "full retail kilowatt-hour rate" but are compensated for the excess generation that is not used to offset the customer-generator's purchases at the applicable PTC rate – two different prices/rates. The PaPUC has long considered the PTC to be the "full retail value" required to be provided to customer-generators for their excess generation under the AEPS Act.[19] Based on the definition of PTC, the "full retail value" amount is something less than the "full retail kilowatt-hour rate" used to price the customer-generator's electricity that offsets its monthly purchases from the EDC because the PTC does not include distribution-related costs (i.e., it consists of only generation and transmission components).

Q21. DOES THE ECONOMIC ANALYSIS FOR INSTALLING BTM DG AND FTM DG SYSTEMS DIFFER?

[17] 73 P.S. § 1648.5.
[18] 52 Pa. Code §§ 75.1-75.72.
[19] 73 P.S. § 1648.5.

A21. Yes, it does. BTM DG systems produce economic value for the customer in three ways: reducing the amount of power purchased from the utility at the full retail rate, being paid for any accrued excess generation at the end of the year at the PTC, and through the creation of alternative energy credits ("AECs"). A customer will work with a developer to appropriately size a solar system relative to their usage pattern to optimize these parameters.

FTM DG systems produce economic value for the customer only through the latter two categories of excess generation payouts and AECs as they typically do not offset substantial amounts of on-site consumption. Because more FTM DG generation is compensated at the lower PTC during the cash-out period than with BTM DG systems (which are largely being compensated for self-consumed energy monthly based on the higher full retail rate), the economics of a FTM DG system are somewhat different.

Q22. HOW WOULD YOU CHARACTERIZE THE TYPES OF CUSTOMER-GENERATORS THAT ARE MEMBERS OF SEIA AND CCSA, THE ENTITIES COMPRISING THE JSA?

A22. The customer-generators the JSA represents are the owners and developers of alternative energy systems up to 3 MW in size that are both customers and generators on PPL's system. We represent customer-generators that are presently developing projects that are in various stages in the development process, but short of full operation. Finally, since our member companies are small generation companies, we have a significant interest in ensuring fair, reasonable, and lawful pricing for future net-metered alternative energy systems. Certainty and predictability are key components to any business enterprise and no different for customer-generators.

Importantly, the customer-generators in our group install and operate generating facilities that produce electricity for delivery to the EDC (here PPL) in excess of the on-site

load of the customer, resulting in cash-out amounts paid by PPL at the end of the net metering year.

Q23. WHAT HAPPENS TO EXCESS GENERATION FROM A BTM DG OR FTM DG NEM SYSTEM THAT IS NOT CONSUMED BY THE CUSTOMER-GENERATOR?

A23. As a matter of physics, the excess power from either a BTM DG or FTM DG system will flow through the customer-generator's electrical meter, onto the Company's grid, and to the nearest source of load, which is almost always the customer-generator's neighbor. At that point, the energy will flow through the neighbor's meter, and PPL will bill that customer for the full retail rate (including all distribution charges, power supply charges, taxes, and fees) for the energy.

Q24. FROM THE BROADER GRID'S PERSPECTIVE, DOES IT MATTER IF POWER FROM A NEM SYSTEM IS CONSUMED BY A CUSTOMER OR EXPORTED TO THEIR NEIGHBOR?

A24. No, it does not. NEM systems that are connected to the Company's distribution grid are sized in a manner where their generation will be consumed within the Company's distribution grid by other customers. For example, the excess generation from an 8 kW_{DC} residential system might power the customer-generator and their neighbor, while the excess generation from a 3 MW FTM DG system may provide power to entire neighborhoods or business districts. But in both of these cases, the energy from the NEM system reduces the need for PPL and energy suppliers to purchase power on the wholesale market. Further, because the NEM systems produce energy close to a customer's load, they avoid line losses that naturally occur between the bulk power grid and a customer's meter. JSA witness Justin Barnes discusses these benefits in more detail in JSA Statement No. 2.

Q25. HOW DOES GENERATION FROM NET METERED DG SYSTEMS INTERACT WITH THE COMPANY'S DSP CONTRACTS?

A25. The Company's small commercial and industrial ("SCI") DSP contracts are load-following, full-requirements contracts. This means that the energy supplier is responsible for delivering all aggregate energy and capacity needs of the default service customer base, and that PPL is billed only for energy and capacity that it uses. When net metered DG systems produce energy that would otherwise have been supplied by a DSP, the amount purchased by the Company from the DSP is reduced, which reduces DSP billings for the respective customer group (e.g., residential or SCI customers).[20]

As more net metered DG systems are installed on the Company's system, they will begin to impact the load shape of PPL's customer base. Given that solar PV produces energy in the middle of the day, it will reduce the share of "on peak" energy procured by the DSP provider.[21] Net metered DG generation also reduces the Company's aggregate peak demand during the five coincident peak ("5CP") hours that are used to allocate PJM generation capacity costs. Given that capacity is a separate PJM product from energy, reducing the Company's 5CP demand will reduce the amount of capacity that a DSP provider must purchase on behalf of the DSP customers, further reducing energy supply costs.[22]

Q26. GIVEN THIS CONTEXT, WHAT IS THE IMPETUS BEHIND THE COMPANY'S PROPOSAL RELATED TO NEM SYSTEMS?

[20] KML Exhibit-2, JSA IV-5(e).
[21] PJM defines peak hours as 7 AM to 11 PM weekdays, excluding holidays.
[22] KML Exhibit-3, JSA IV-4(b).

A26. The Company's stated reasons, which I discuss in more detail in the next section of my testimony, boil down to two concerns. First, the Company claims that the current customer supply rate classification between the GSC-1 and GSC-2 rate schedules does not match the scale of FTM DG systems nor the "stress" they place on the distribution system.[23] Second, PPL claims that paying for FTM DG excess generation at the PTC will create a vicious cycle of cost increases that will drive up the PTC for all small commercial customers.[24] Based on my analysis, I find substantial problems with both of these claims.

Q27. IS THERE TOO MUCH POWER CURRENTLY BEING DELIVERED FROM CUSTOMER-GENERATORS TO PPL AND OTHER PENNSYLVANIA UTILITIES?

A27. No. As a primary matter, most of the concerns that the Company raises related to FTM DG systems remain hypothetical as very few of these systems are actually online and producing power. It is true that the Company has identified a sizable list of projects that have expressed interest in connecting to its system, but the challenges to developing FTM DG systems – including obtaining equipment and permits in a timely manner, securing financing, and not triggering expensive interconnection upgrades – are great and many projects that have applied for interconnection will ultimately not be developed.

More broadly, Pennsylvania and other states are in the midst of an unprecedented period of load growth driven by electrification, manufacturing, and most of all, data centers. PPL projects an increase in 54 gigawatt-hours of sales from electric vehicles in its territory between 2025 and 2027, equal to adding the annual usage of approximately

[23] PPL Statement No. 15, pp. 3, 6.
[24] *Id.* at 7.

5,300 residential customers.[25] While this is a meaningful increase in demand, it is nothing compared to the Company's forecast for data centers and other large load customers: "The pipeline of [large load customer] projects exceeds the Company's current peak load of 7.8 GW. In practical terms, that means the Company is preparing to more than double its system demand in just 5–6 years—growth that took over a century to reach."[26]

This is a staggering statement. While it is true that FTM DG system and large load customers connect to different parts of the Company's grid and face different retail rates, they are all supplied by the PJM wholesale market. Any headroom that FTM DG systems can provide to reduce the peak demand that PPL as a whole will experience will lead to lower power supply and transmission costs for all customers. Further, due to the interconnection backlog and continued challenge of connecting large generators to the PJM bulk energy system, FTM DG systems are among the few that can come online and provide power in months, not years.

Q28. WHAT OTHER BENEFITS DO CUSTOMER-GENERATORS AND THEIR DG SYSTEMS PROVIDE AN EDC, OTHER UTILITY CUSTOMERS, AND THE LOCAL ECONOMY?

A28. Customer-generators and their DG systems provide many utility-related and non-utility-related benefits to residents and businesses operating in the Commonwealth. For a BTM DG customer, generation helps reduce the individual customer's consumption from the grid, reducing their bills. It can also help reduce power flows on the distribution grid (as

[25] PPL Statement No. 4, p. 11. EV usage was 105 GWh in 2025 and 159 GWh in 2027. Based on the average EIA residential customer usage of 10,191 kWh per year, this is equal to 5,298 residential customers.
[26] PPL Statement No. 16, p. 15.

discussed in more detail below) and potentially extend the time before a utility must upgrade expensive electric system assets.

Both BTM DG and FTM DG systems reduce peak demand on PPL's grid whenever they produce power during the hot summer afternoons that drive PJM's summer peak. This reduction benefits all of PPL's utility customers, including customer-generators and non-customer-generators, through the reduction in generation capacity and transmission costs that are allocated to all PPL customers by PJM.[27]

Finally, DG systems utilize private investment from customer-generators to provide energy and capacity via systems whose capital costs are not recovered through the Company's rate base. Further, installing DG systems requires substantial manpower and supports jobs in and around PPL's territory.

Q29. GIVEN THIS CONTEXT, DO YOU BELIEVE THAT PPL'S PROPOSAL REGARDING FTM DG SYSTEMS IS NECESSARY OR REASONABLE?

A29. No. On balance, PPL's proposal would likely reduce the number of FTM DG systems that would be developed in its territory. This comes at a time when overall demand is rapidly climbing and wholesale energy prices are experiencing substantial upward pressure. As I discuss in the next section, the Company's rationale for its proposal is not well-founded. Implementing its proposal could risk throttling one of the few generation resources that can rapidly come online just when more generation is needed.

[27] KML Exhibit-4, JSA IV-4.

III. THE COMPANY'S MAXIMUM REGISTERED PEAK LOAD PROPOSAL SHOULD BE REJECTED

PPL MRPL Proposal Overview

Q30. PLEASE DESCRIBE PPL'S MAXIMUM REGISTERED PEAK LOAD PROPOSAL.

A30. PPL proposes to modify the criteria that determines how customers are assigned to one of the two Generation Supply Charge ("GSC") tariff options (i.e., GSC-1 or GSC-2) offered by the Company. GSC-1 is applicable to residential and small commercial customers, and currently is available to customers with a peak demand of less than 100 kW based on "the customer's ICAP[28] peak load contribution to PJM peak load assigned for the most recent PJM Planning Year".[29] GSC-1 features a fixed price option, where each kWh of energy is charged a known rate based on the full service contracts procured through the Company's default service procurement process.

GSC-2 is currently applicable to larger customers with a peak load greater or equal to 100 kW and functions as a wholesale passthrough rate. On this tariff, customers are charged for energy at the actual hourly real-time Locational Marginal Price ("LMP") at the Company's PJM aggregation node and charged for capacity at the PJM Reliability Pricing Model ("RPM") price applicable to the customer's peak load capacity ("PLC") obligation.[30]

PPL proposes to modify how peak demand is calculated for determining a customer's default service assignment. Currently, the PJM PLC obligation is used, which is based on the customer's peak demand placed on the grid during the 5CP hours that are

[28] ICAP refers to installed capacity.
[29] PPL Electric Exhibit GEO-1, p. 287.
[30] *Id.* at 306.

used by PJM to assign capacity costs to customers. These hours are – by definition – the five highest PJM-wide load hours that fall on different non-holiday, non-weekend days during June through September.[31] Historically, the 5CP hours have fallen during the mid- to late-afternoons driven by hot days and air conditioning loads.[32]

In its proposal, PPL creates a new definition, the Maximum Registered Peak Load, which represents the highest level of power flow "from or into the Company's distribution or transmission system" in any 15-minute period in a 12-month period ending September 30.[33] This new definition will supplant the prior PJM PLC peak demand value for determining whether a customer is placed on GSC-1 or GSC-2. For BTM DG customers, this new measure will be the larger of the power flow from the grid *and* the power flow to the grid. For FTM DG customers, the MRPL will largely be a function of the alternative energy system's electric output as there is little onsite load to offset exports to the grid.

Q31. WHAT JUSTIFICATION DOES THE COMPANY PROVIDE FOR ITS MRPL PROPOSAL?

A31. The Company offers the following explanation as to why the change is necessary:

> The Company's currently effective tariff, which was last updated in the 2015 Rate Case, does not classify customers based on their maximum registered peak load as set forth in the proposed retail tariff. Instead, for example, a small commercial customer's demand is determined based on their load independent of the nameplate capacity of any behind-the-meter generation. This current practice fails to reflect the stress that the behind-the-meter generation puts on PPL Electric's distribution system. Additionally, the current classification results in non-net metering Small C&I default service customers disproportionately subsidizing the

[31] PJM RTO 5 Coincident Peaks (CPs), PJM Knowledge Community. Available at https://pjm.my.site.com/publicknowledge/s/article/PJM-RTO-5-Coincident-Peaks-CPs899539?language=en_US

[32] Most 5CPs in recent years have fallen between 5-6 PM EPT, although some years had earlier peaks. See e.g., https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2025-peaks-and-5cps.pdf

[33] PPL Electric Exhibit GEO-1, p. 11, KML Exhibit-5, JSA II-8(d). PPL confirmed the 15-miinute basis for the MRPL calculation in its response to JSA II-8(d).

annual cash-outs of customer generators that are, effectively, merchant generators.[34]

Q32. WHAT IS YOUR RESPONSE TO THESE STATEMENTS?

A32. I will address the three issues identified by PPL as driving its new proposal (i.e., grid stress, customer classification, and subsidization or cost-shift) separately. Because the Company's testimony on these matters is quite limited, additional discovery was required to further explore PPL's rationale. Our review of these discovery responses demonstrated that PPL's "grid stress" and "subsidization" arguments are poorly supported, contain unreasonable assumptions, and are contradicted by facts and information provided by the Company itself. At the same time, its customer classification methodology runs contrary to cost-causation principles. In short, none of the Company's justifications for its MRPL proposal hold up to scrutiny.

BTM DG and FTM DG Do Not Increase "Stress" on the Distribution Grid

Q33. DID THE COMPANY ELABORATE ON WHAT IT MEANS BY "STRESS" THAT IT CLAIMS BTM DG AND FTM DG CUSTOMERS PLACE ON THE SYSTEM?

A33. Yes. In response to discovery about this issue, the Company responded

> Stress refers to the wear and tear on all distribution equipment. Regardless of the direction of power flow, exported generation causes a similar level of wear and tear on distribution system components. However, line transformers often experience greater damage under the same export demand compared to load because differing load profiles can lead to overheating. Overall, there is no significant difference between the impact of load and generation power.[35]

Q34. DOES THE COMPANY'S MRPL PROPOSAL HAVE ANY IMPACT ON DISTRIBUTION RATES OR DISTRIBUTION TARIFF CLASSIFICATION?

[34] PPL Statement No. 15, p. 6.
[35] KML Exhibit -6, JSA 1-11(a).

A34. No, as supported by the following Company confirmations related to the MRPL and the distribution grid:

- The Company does not consider an individual customer's use of the distribution system independently from other customers but instead considers the aggregate impact of customers taking service on specific distribution assets.[36]
- In "most cases", the Company considers the diversified demand of all customers being served by an asset when sizing distribution infrastructure assets.[37]
- If an individual customer hits its individual peak demand at a time when the distribution assets serving that customer are not near their peak demand, there are no incremental costs to serve this individual customer's peak demand.[38]
- All distribution assets downstream (i.e., in the direction of the customer and its facilities) of a substation are already configured to allow two-way power flow, and the Company currently conducts reviews to ensure that "all distribution devices downstream of a substation operate safely and reliably under two-way power flow conditions."[39]
- PPL's current interconnection practices and standards are designed to ensure the safe and reliable operation of its distribution system.[40]
- A customer's distribution rate will not be impacted if that customer is reassigned from GSC-1 to GSC-2.[41]
- The MRPL "would not be considered when setting a customer's base distribution rate."[42]
- A customer would not be moved from one distribution rate to another if it installed an alternative energy system, and "the existence of a PV system has no bearing on the customer's base distribution rate schedule."[43]
- Exported power and the amount of power consumed are not used to develop customer distribution billing kW values.[44]

In other words, the MRPL proposal is completely and totally independent of any matters related to distribution rates, distribution charges, or distribution tariff customer

[36] KML Exhibit -7, JSA 1-14.
[37] KML Exhibit -8, JSA I-15.
[38] KML Exhibit -9, JSA I-17.
[39] KML Exhibit -10, JSA I-18.
[40] KML Exhibit -11, JSA I-20.
[41] KML Exhibit -12, JSA II-10.
[42] KML Exhibit -13, JSA II-15.
[43] KML Exhibit -14, JSA II-16.
[44] KML Exhibit -15, JSA II-17.

classifications. The Company does not propose billing customer-generators different distribution rates based on their supply rate classification, nor based on the MRPL of their alternative energy system. Thus, PPL is on the one hand treating FTM DG customers as "small" for purposes of their distribution rate as a customer, but then inconsistently characterizes these same customers as "large" for purposes of compensation for excess generation from their alternative energy systems.

Q35. IF THE COMPANY'S MRPL PROPOSAL HAS NOTHING WHATSOEVER TO DO WITH DISTRIBUTION RATES, IS ITS CONCERN ABOUT FTM DG NEM SYSTEMS CAUSING "STRESS" ON THE DISTRIBUTION GRID RELEVANT?

A35. No. Setting aside the merits of the claim (which I discuss below), justifying any element of the MRPL proposal on the supposed impacts to the distribution system and the costs to provide safe and reliable distribution service is incompatible with the Company's complete isolation of the MRPL concept from anything related to distribution customer classification or rates designed to recover those distribution costs in a fair and balanced manner.

Moreover, if a FTM DG customer were to cause any impacts on the distribution grid, they would be "required to pay the entire cost of distribution system upgrades identified by PPL Electric during the interconnection study/facility impact study process."[45] Further, these costs are treated by the Company as contributions in aid of construction ("CIAC"), which "offset the capital cost placed in rate base. Therefore, the amount of CIACs is not recovered in distribution rates."

[45] KML Exhibit-16, JSA III-4.

In summary, if a FTM DG customer causes any undue stress on the distribution grid or would cause it to operate unsafely or jeopardize reliability, the customer would have to pay for all electric system upgrades deemed necessary by PPL during the interconnection study process prior to connecting to the grid, and none of those costs would be recovered from other customers.

Q36. DID THE COMPANY PROVIDE ANY ADDITIONAL DETAILS ON ITS CLAIMS ABOUT THE WEAR AND TEAR ON THE DISTRIBUTION SYSTEM?

A36. Yes. The Company provided several important pieces of information in discovery that were missing in its testimony. First, it indicated that the wear and tear varies by system component:

> Non-transformer equipment experiences typical wear and tear as a function of thermal loading. Devices that utilize electrical or mechanical switching components have an expected finite number of operations. Capacitor and voltage regulator operations, for example, are primarily driven by voltage and reactive power fluctuations. Recloser operations are primarily driven by utility switching or established protection schemes.
>
> Other distribution components—such as conductors, fuses, switches, and regulators—do not follow the same non-linear wear pattern as transformers. Conductors primarily degrade through thermal cycling and environmental exposure, which is largely linear with respect to loading. Fuses experience no progressive wear and fail only upon operation. Switches, voltage regulators, and other in-series devices that have a component of electrical or mechanical switching can experience degradation both from a current flow perspective and a number of operations perspective. The wear and tear of these switching devices is not related to the level of loading but to the cyclical nature of the load.[46]

Q37. IS THERE ANY REASON TO THINK THAT FTM DG WOULD IMPACT, FOR INSTANCE, THE FREQUENCY OF RECLOSER ACTIVATIONS?

A37. No. Distribution equipment such as fuses, switches, and reclosers that are indicated to have a "finite number of operations" respond to unusual system conditions, such as trees

[46] KML Exhibit -17, JSA III-12(c-d).

falling on wires or sudden equipment failures that cause unexpected voltage or fault currents that need to be remediated. There is no reason to believe that FTM DG would trigger these equipment protection regimes as a matter of normal operation and, if any unusual power quality issues were projected to arise from the installation of such a solar system, the developer of the system would be required to pay for the upgrades required to mitigate the conditions.

Similarly, as discussed below, FTM DG does not increase power flow through other equipment, such as conductors or switches, because such alternative energy systems do not change the *downstream power flow* (i.e., in the direction of the customer and its facilities) being consumed by customers. Instead, FTM DG will reduce power flows *upstream* of the interconnection point (i.e., in the direction of the utility) and thus reduce the thermal loading of the assets that drive a portion of the distribution system wear and tear.

Q38. HOW DO TRANSFORMERS EXPERIENCE WEAR AND TEAR?

A38. Transformers function differently from other distribution system equipment. Per the Company, transformer wear and tear is defined in IEEE[47] Standard C57.91-2011, which describes the non-linear relationship between load and transformer wear and tear.[48] In essence, as the load on a transformer increases, it increases the temperature of the cooling fluid inside the transformer. And when power flows through the transformer when the cooling fluid is hot, it will degrade the insulation inside the transformer more quickly, leading to accelerated aging. But importantly, this accelerated aging only occurs when

[47] IEEE stands for the Institute of Electrical and Electronics Engineers, a large, global professional organization for engineers, scientists, and allied professionals in technology, known for setting standards and fostering innovation in electrical, computer, and electronic fields for the benefit of humanity.
[48] KML Exhibit -18, JSA III-12(a-b).

loads are in excess of the design rating of the transformer. In fact, the Company stated that "normal life expectancy of a substation transformer is considered to be risk free below each transformer's nameplate rating loading level."[49]

In other words, per the IEEE standard that PPL uses for transformer wear and tear and assumed useful life calculations, there is no increase in wear and tear on any transformer as long as the load is at or under the transformer's rated capacity. Further, the accelerated aging of transformers has a strong, exponential relationship with transformer temperature, which is itself a function of loading.

Q39. PPL CLAIMS THAT LINE TRANSFORMERS "OFTEN EXPERIENCE GREATER DAMAGE UNDER THE SAME EXPORT DEMAND COMPARED TO LOAD BECAUSE DIFFERING LOAD PROFILES CAN LEAD TO OVERHEATING." IS THIS STATEMENT CONSISTENT WITH ITS OTHER STATEMENTS ON THIS ISSUE?

A39. No, it is not. In one discovery response, the Company claims that the generation profile of behind the meter generation "often" leads to greater line transformer damage, but another response indicates that line transformer damage only accelerates if the transformer is loaded beyond its rated capacity. Given that the Company screens for adequate transformer capacity as part of its interconnection protocols and will not approve a PV system that will consistently overload a line transformer without remediation, the conditions that the Company claim occur "often" in fact are prohibited by its own policies.

It is important to remember that the primary driver behind PPL's MRPL and customer supply rate classification proposal is not BTM DG systems, but instead FTM

[49] KML Exhibit -19, JSA III-12(g)(ii).

DG systems. These FTM DG systems connect to the Company's distribution grid either through an existing line transformer with sufficient capacity or through a dedicated line transformer that is appropriately sized for the installation. And, in neither of these cases is the Company likely to allow transformer overloading as part of normal operating conditions. Thus, as long as the Company follows its own interconnection protocols, the expected generation of both BTM DG and FTM DG systems will not accelerate aging of line transformers and thus will not cause any cost recovery mismatch between the expected and actual life of those assets.

Q40. FUNCTIONALLY SPEAKING, ARE THE POWER FLOWS FROM FTM DG SYSTEMS LIKELY TO INCREASE OR DECREASE LOADS ON DISTRIBUTION ASSETS?

A40. To the extent that the "wear and tear" on distribution components is a function of power flows through those components, as the Company implies, then the presence of solar PV generation can substantially reduce power flow through many distribution assets for many hours in the year. This should reduce, not increase, wear and tear on these components.

On a first order basis, FTM DG systems will reduce power flows upstream of the system and not impact power flows downstream of the system. An exception to this may occur when the FTM DG system is located near the end of the feeder and "pushes" more power upstream to serve customer load. In this case, a FTM DG system may increase power flow in the upstream direction beyond the downstream levels before the FTM DG system was installed.

Imagine a very simplified radial feeder that serves two residential neighborhoods and two office buildings.[50] In the examples below, the loads and generation in MW are notated under the icon, and the numbers on the wires represent the power flow through that branch of the feeder. Without any FTM DG on the feeder, the power flow will be strictly one-way from the distribution substation **(A)** to the end loads **(B, C)**. Each component will carry the sum of power demands of customers downstream, and in this instance, the power flow from the transmission system through the substation transformer will be 2.6 MW, as shown in Figure 2 below.

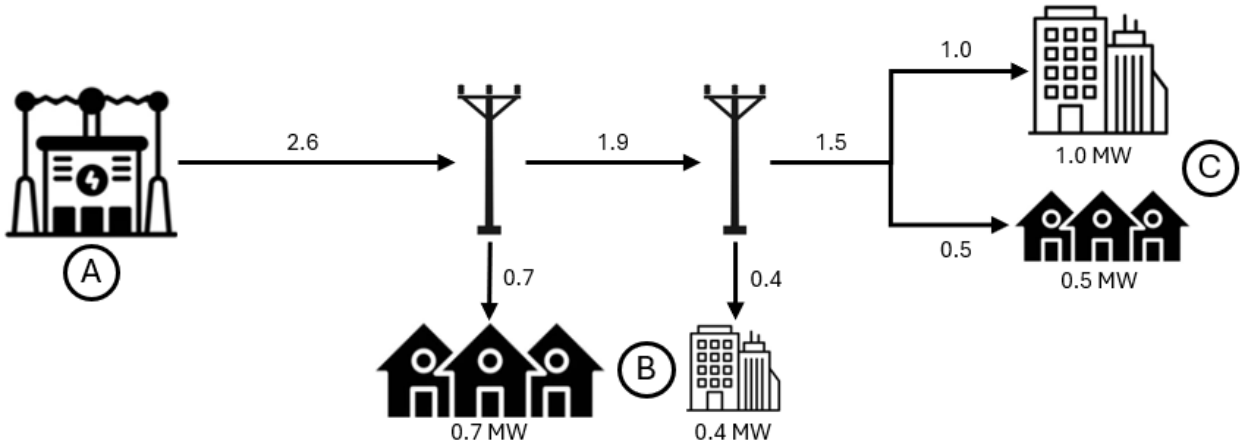

Figure 2 - Hypothetical Feeder – No Solar

The addition of a 2.0 MW FTM DG system **(D)** next to the substation shown in Figure 3 below will not change power flows through the downstream portions of the feeder as these are still dictated by the power draws from each of the attached customers. However, the solar system will substantially decrease the power flow through the substation transformer, reducing it from 2.6 MW to 0.6 MW as 2.0 MW of load from the residential and commercial buildings are now being supplied by the FTM DG system.

[50] This hypothetical example ignores line losses and second order voltage and reactive power impacts. The latter are studied as part of any interconnection application and must be kept within specified ranges to ensure safe and reliable operation of the distribution grid.

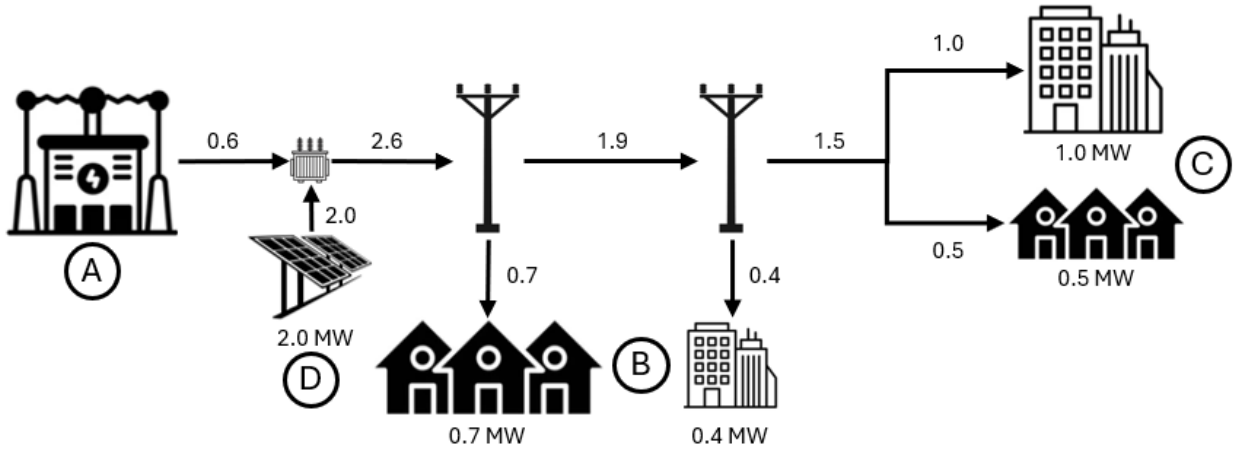

Figure 3 - Hypothetical Feeder – FTM DG Near Substation

In the next example in Figure 4 below, the FTM DG system is added much further downstream **(E)**. In this case, the power from the solar system serves the large office and small residential neighborhood (**C**) with power to spare. That power continues to flow upstream to supply the second office building **(B)**. A small portion (0.1 MW) still remains and partially serves the upstream residential neighborhood. That power is supplemented by 0.6 MW of power from the substation, the same as in the example above. Notably, while the power flows are reversed in this example, none of them are higher than the original, non-solar power flows shown in Figure 2.

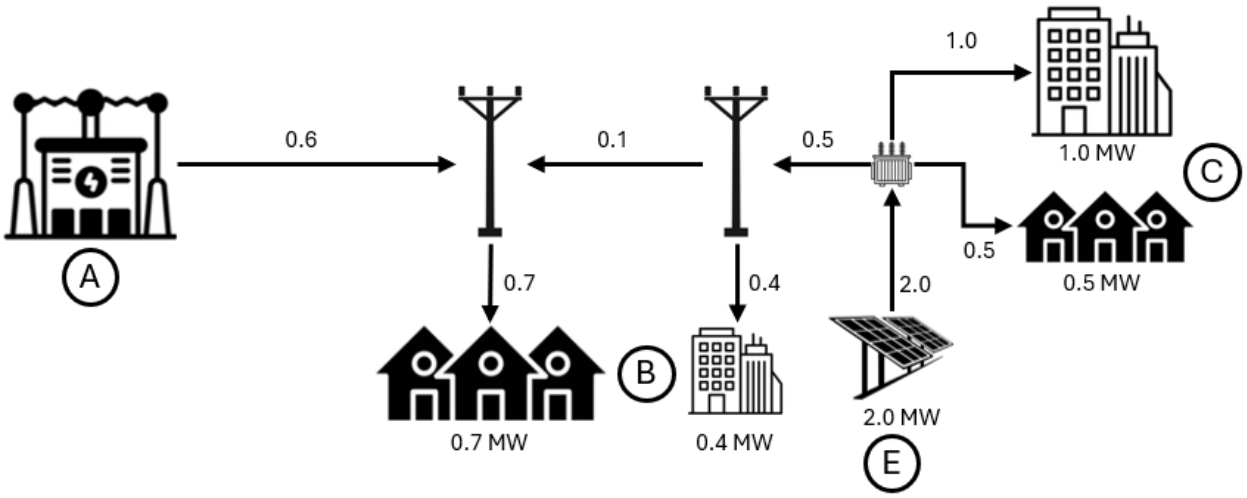

Figure 4 - Hypothetical Feeder – FTM DG Far From Substation

Q41. WHAT DO THESE SIMPLIFIED EXAMPLES SHOW ABOUT THE ADDITION OF FTM DG ON THE DISTRIBUTION FEEDER?

A41. In these examples, the power flows of the distribution assets are all reduced or kept the same while solar is generating. During those hours, the solar generation serves part of the feeder load and power flows through the substation transformer are reduced. Power flows through conductors are also reduced relative to the loads they experienced before the FTM DG solar was added. Lower power flows mean lower thermal loading, which for many distribution assets is a key driver of wear and tear.

Q42. DOES THIS MEAN THAT THE PEAK DEMAND ON THE FEEDER IS ALSO REDUCED?

A42. Not necessarily as it depends on when the peak demand on this feeder occurs. If the loads on the feeder peak during summer afternoons, then it is highly likely that solar will be generating during many high load hours and could help reduce peak demand on the feeder and delay or defer upgrades. Alternatively, if the feeder peaks in the winter mornings, then solar will be producing much less power during the peak and it may not reduce the overall peak demand.

Q43. HOW, IF AT ALL, WILL THIS SITUATION CHANGE AS MORE AND MORE FTM DG SYSTEMS ARE ADDED TO THE COMPANY'S GRID?

A43. The situation may change as the amount of FTM DG increases, but this will be highly dependent on the specific sites that projects select. For instance, the Company indicated that only six of 364 substations currently experience reverse power flow.[51] It also indicated that if all projects in the interconnection queue were to connect to the Company's system, 99 substations would be forecasted to experience reverse power flow

[51] KML Exhibit-20, JSA V-10(a).

and 10 new substations would be required to accommodate the new load. Of course, these upgrades would be required to be paid for in full by the connecting customer-generator prior to their system being approved.

Q44. DO YOU FIND IT LIKELY THAT A FTM DG PROJECT THAT WOULD BE REQUIRED TO CONSTRUCT AND PAY FOR COSTLY UPGRADES OR A NEW SUBSTATION TO INTERCONNECT TO THE COMPANY'S GRID WOULD PROCEED IN THE DEVELOPMENT PROCESS?

A44. No. High interconnection upgrade costs are a leading cause of projects dropping out of the interconnection queue. If a project were required to spend millions of dollars to fund a new substation upgrade, or tens of millions for an entirely new substation, that project would likely no longer be economic nor likely to be developed.

Q45. PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT THE COMPANY'S "WEAR AND TEAR" ARGUMENT USED TO SUPPORT ITS MRPL PROPOSAL.

A45. The PaPUC should give this argument no weight. The Company's use of distribution-related arguments to determine a customer's supply service is inconsistent. Power supply rate classifications should be a function of the costs and loads a customer-generator places on the bulk power grid, not the distribution system. PPL's claims that BTM DG and FTM DG cause "stress" and increase "wear and tear" on distribution equipment is neither relevant nor accurate as demonstrated by its own discovery responses.

Finally, BTM DG and FTM DG projects can have a beneficial impact on the wear and tear of distribution assets as these systems will often reduce demands and thus the thermal loading that actually causes accelerated aging. Systems that fail to do so will be

responsible for sizable financial upgrade costs that would likely render the projects uneconomic, and thus not be built.

The MRPL Customer Classification Proposal Runs Counter to Cost-Causation Principles

Q46. WHAT ISSUES DO YOU SEE WITH THE COMPANY'S MRPL CUSTOMER CLASSIFICATION PROPOSAL?

A46. PPL proposes to classify customers as either GSC-1 or GSC-2 customers based on not only the amount of their consumption from the grid but, for customer-generators, the maximum power they deliver to the grid via net metering. Importantly, this calculation is based on any 15-minute period over the entire year and is not limited to the 5CP hours that determine capacity and transmission cost responsibility.[52] It is also a major change from the current process of defining peak load as the "customer's ICAP peak load contribution to PJM peak load assigned for the most recent PJM Planning Year."[53] A customer's ICAP peak load contribution is the appropriate measure of peak demand when considering power supply costs because it is the basis for how PJM assigns power supply costs to PPL.

Q47. WHY IS THIS A PROBLEM?

A47. It is a problem because the Company is using an individual customer's non-coincident peak ("NCP") demand to determine which supply service the customer must take. A customer's NCP demand is the highest level of demand it attains independent of timing, and independent of tother customer loads. For example, if a customer takes service on a distribution feeder that peaks at 3 PM on summer afternoons, but that individual customer

[52] KML Exhibit-21, JSA II-8(d).
[53] PPL Electric Exhibit GEO-1, p. 287.

experiences their peaks at 10 AM on Saturday morning, their load profile is actually helping reduce the cost to serve all the customers on the distribution circuit the customer-generator is connected to because they are not maximizing their use during the same time the distribution circuit/feeder is experiencing its overall peak. Regardless of this fact, the Company's proposal will penalize the customer for higher use during off-peak times, even when this load profile is beneficial to the system.

An individual customer's NCP demand has nothing to do with generation or transmission cost causation because it can, by definition, occur at different times than the collective, or coincident peak ("CP") of all customers being served by an asset. Because of this, individual customer NCP demand should be used in extremely limited cases in both cost-of-service studies ("COSS") and rate design, and not be applied to generation and transmission rates for assets that serve thousands or millions of different customers.

In a COSS, individual NCP demand should only be applied to assets that are unlikely to experience any load diversity, such as service drops that typically only serve a single customer. Nearly all assets on the distribution grid, including substations, feeders, and large transformers, are sized to meet the aggregate diversified demand of all customers taking service from those assets and should be analyzed as part of a broader measure of demand, such as the class NCP (the peak of all customers in a given class) or the CP peak (the demand of a customer at the time the overall system is peaking).

On the rate design side, although many commercial tariffs include NCP demand charges, they should be limited in their application and only applied to revenue recovery for assets that experience less load diversity. If stakeholders wish to implement demand charges to recover revenue for shared assets, some measure of CP demand should be

used. This may be, for instance, the highest measured demand between 3 PM and 6 PM in summer afternoons when the transmission and generation systems are most likely to peak.[54] This approach ensures that a customer's demand used in tariff classification or monthly billing is reflective of the costs they are actually imposing on the system.

Q48. WHAT ARE THE RAMIFICATIONS OF THE COMPANY'S PROPOSAL?

A48. All customers, whether they are customer-generators or not, could be misclassified for their power supply service based on a measure of demand that has nothing to do with the cost of providing them with power supply service. Imagine that a commercial customer-generator with a weekday peak load of 100 kW that closes on the weekend decides to install a 200 kW BTM DG system. Although the alternative energy system does not produce 200 kW every hour of the day, it produces a meaningful amount in the middle of the afternoon when grid load is high, particularly on hot, sunny days that drive the air conditioning use that leads to high demand. On those days, which are likely to contain the 5CP hours, the customer's net demand may be close to zero during the hours that trigger generation cost allocation to PPL.[55]

By contrast, when the business is closed on the weekdays, and demand falls to something close to zero, the solar PV generation output in the middle of the day could peak at or near 200 kW capacity of the solar system. Under the Company's MRPL

[54] Many rate design and cost of service analysts, including myself, prefer to use volumetric time of use rates to collect the vast majority of revenue from customers. This provides a consistent and ongoing price signal for optimal consumption in a way that demand charges do not, particularly as distributed generation and demand-side management technologies expand. See e.g., *Smart Rate Design for a Smart Future*, Regulatory Assistance Project (available at https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/) and *Electric Cost Allocation for a New Era: A Manual*, Regulatory Assistance Project (available at https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/).

[55] In an analysis I performed in the Citizens' rate case, I found that a fixed-tilt solar project produced on average 41.8% of its capacity during the 5CP hours over the past five years. On average, this would produce 84 kW from a 200 kW system, leading to a net load of 16 kW. See Surrebuttal Testimony of Kevin Lucas on Behalf of Kelly Road Solar, LLC, Lancaster Avenue Solar, LLC, And Twilight Renewables, LLC, Revised, at 36.

definition, the much larger weekend exported solar value of close to 200 kW would be used to shift the customer to the GSC-2 tariff, even though this export at noon on a Saturday has – by definition – absolutely nothing to do with the assignment of generation costs to the Company.[56] Any cost impacts that might be caused by this exported power would be 1) limited to the distribution system, 2) paid for by the customer as a condition of interconnecting the solar system, and 3) more likely to reduce load than increase load on upstream assets.

Q49. IS THIS SITUATION ANY DIFFERENT FOR A FTM DG SYSTEM THAT IS NOT OFFSETTING ANY BEHIND THE METER LOAD?

A49. No, it is not. The exact same relationship to PJM generation cost allocation applies to FTM DG systems because the FTM DG system is always reducing the Company's peak demand anytime it is producing energy during the 5CP hours. There is, quite literally, no way that FTM DG generation can increase capacity costs as all generation from these systems is consumed downstream of the PJM settlement point and only serves to reduce the peak demand that PPL as a whole consumes during the PJM system peaks.

Q50. WHAT DO YOU RECOMMEND WITH RESPECT TO THE MRPL DEFINITION?

A50. The definition's reliance on power usage during any 15-minute period in the day to determine the supply rate is highly problematic. This is particularly true given the proposed expansion to include the maximum flow in either direction. Power flows from BTM DG systems onto the grid are unlikely to increase generation (or transmission) costs and only serve to reduce the levels of power that must be supplied by – and purchased from – PJM. I recommend that the PaPUC reject the proposed MRPL customer

[56] Recall that PJM's 5CP definition explicitly excludes weekends.

classification definition and retain the existing customer classification definition to only consider power flow to the customer during the 5CP hours when generation capacity costs are set.

The Company's Cost Shift Argument is Fatally Flawed and Should be Disregarded

Q51. PLEASE SUMMARIZE THE ANALYSIS THAT THE COMPANY PERFORMED RELATED TO COST SHIFTS ASSOCIATED WITH FTM DG CUSTOMERS.

A51. The Company performed an analysis that purported to show that FTM DG customers would soon result in annual cash-outs for the SCI class "approximately $60 million to over $300 million by 2029."[57] This range is supposedly based on project attrition rates from 75% ($60 million) to 36% ($300 million), although the Company's analysis contains an error in the latter value that would either require zero project cancellations or result in a much lower cost impact if 36% of projects were in fact cancelled.[58] As a result of these cash outs, the Company projects that the PTC that SCI customers would face would increase from $0.11386/kWh in 2024 to $0.29515/kWh in 2030, an untenable situation.[59]

Q52. HOW DOES THE COMPANY ARRIVE AT THESE VALUES?

A52. The Company begins by determining the amount of generation it projects on an annual basis from new FTM DG projects that have applied for interconnection. It then calculates the share of these projects that it expects to come from GS-3 customers (i.e., commercial customers connecting at secondary three-phase voltage levels), which it

[57] PPL Statement No. 15, p. 7.
[58] PPL Statement No. 15, p. 7, footnote 1. The Company's workpapers showing a 36% cancellation rate can only be reconciled with the other two workpapers showing a 50% and 75% cancellation rate if the first workpaper in fact assumes zero project cancellations.
[59] PPL Electric Exhibit AC-1.

estimates at 35%.[60] As new projects come online each year, the Company calculates the annual cash-out payments based on the then-in-effect PTC value by multiplying the PTC by the projected excess generation bank. This value, denoted the "SCI Net Metering Expense from MGs" in PPL Witness Castanaro's workpapers, is added back to SCI procurements costs in the reconciliation process via the "E Factor Rate." Because the excess generation cost is now recovered in the next Default Service Plan cycle, it pushes up the total energy supply procurement cost. And, because the Company (improperly) assumes that procurement costs stay the same as more FTM DG is added to the system, each iteration of excess generation payout / E Factor reconciliation / PTC calculation becomes a self-reinforcing cycle that drives the PTC higher and higher for all SCI customers.

Q53. WHAT PROBLEMS HAVE YOU IDENTIFIED IN THE COMPANY'S ANALYSIS?

A53. The Company's analysis contains several problems, each of which I address below. These include:

- An error in the cancellation rate assumptions
- Overestimating generation from FTM DG projects
- Using constant energy procurement costs even as new FTM DG is added
- Failing to recognize any benefits from FTM DG projects

Together, these errors render the Company's analysis meaningless, and it should be disregarded by the PaPUC in its entirety.

Q54. PLEASE DISCUSS THE FIRST ERROR RELATED TO THE PROJECT CANCELLATION RATE.

A54. The Company presented three different exhibits, each purporting to show the impact of different project cancellations rates of 36%, 50%, and 75%, respectively.[61] Upon

[60] KML Exhibit-22, JSA VI-2 Attachment 1; OCA I-1 Attachment 14 (Castanaro).
[61] PPL Electric Exhibit AC-1, AC-2, and AC-3.

reviewing the exhibits, and the workpapers supporting the exhibits, it became clear that the file that assumed a 36% project cancellation rate did not correspond to the other two exhibits.

Table 1 below shows the estimated excess energy from FTM DG systems that is to be cashed out at the end of each year based on the assumed project cancellation rate. When these values are divided by the project success rate (which is 1 minus the cancellation rate), they should be identical to each other and equal to the total generation if all FTM DG projects were built. This is because this calculation "undoes" the impact of the cancellation rate, revealing the starting generation assuming all projects were built.

The calculation works for the 50% and 75% workpapers (producing 2026 results of 60,202,852 kWh) but fails for the 36% workpapers (producing 2026 results of 94,066,955 kWh). More notably, the generation if all projects were built for the 50% and 75% cancellation workpapers is exactly equal to the assumed generation in the 36% cancellation rate and the calculated value if 0% of projects are cancelled. This result clearly indicates that the Company's workpaper that produced the highest cost impact associated with FTM DG annual cashout payments did not decrease projects by 36% as PPL claimed but instead assumed a 100% success rate.[62]

Excess kWh	2026	2027	2028	2029
Company Generation Assumption				
36% Cancellation	60,202,851	391,960,372	932,128,980	1,430,455,085
50% Cancellation	30,101,426	195,980,186	466,064,490	715,227,542
75% Cancellation	15,050,713	97,990,093	233,032,245	357,613,771
Generation if 100 % Success Rate				
0% Cancellation	60,202,851	391,960,372	932,128,980	1,430,455,085
36% Cancellation	94,066,955	612,438,081	1,456,451,531	2,235,086,070

[62] The values in the "Generation if 100% Success Rate" were calculated by dividing the Company assumed generation by (1 – Cancellation rate). For instance, the value for 2026 for 75% cancellation is 15,050,713 / (1 – 0.75) = 60,202,852.

50% Cancellation	60,202,852	391,960,372	932,128,980	1,430,455,084
75% Cancellation	60,202,852	391,960,372	932,128,980	1,430,455,084

Table 1 – PPL FTM DG Generation Assumptions

Q55. WHAT IS THE IMPACT OF THIS ERROR?

A55. The Company's $300 million figure is not based on a 36% cancellation rate as it claims but instead on a 0% cancellation rate. At a minimum, it removes the top end of the Company's estimate for cost impacts as it is completely unrealistic to assume that no customer-generator projects would be cancelled between now and 2029.

Q56. PLEASE DESCRIBE THE NEXT ERROR RELATED TO THE ASSUMED GENERATION FROM FTM DG PROJECTS.

A56. In discovery, the Company confirmed that it received projected generation (i.e., kWh) data from some but not all FTM DG projects in the application process. For projects in which the Company did not receive production forecasts, "it estimates energy output by multiplying the Alternating Current (AC) MW nameplate capacity of each application by 2,609, which represents the standard annual hours of sunlight."[63] The Company further explained that this value is sourced from the National Oceanic and Atmospheric Administration ("NOAA"), although it was not readily apparent where the specific value was found and whether it represents a state-wide average or a PPL-specific average.[64]

Q57. IS THIS A COMMON METHOD TO ESTIMATE GENERATION FROM SOLAR PROJECTS?

A57. No. I have never heard of this particular method for estimating solar generation, and problems in using this approach are immediately obvious. First, depending on the metric's definition, it may represent the total number of hours that have a minimum

[63] KMLExhibit-23, JSA 1-26(j).
[64] KML Exhibit-24, JSA III-15(a). I was not able to find the source of this value or this metric on several of NOAA's data-related webpages.

amount of sunny minutes, a measure of average insolation over the course of a year, or some other metric. It is unclear how passing clouds would be factored in, or whether this metric accounts in any way for the difference in the orientation of a PV panel and the sun. Finally, the Company does not appear to differentiate the assumption based on whether a system is fixed-tilt or whether it is a single-axis tracking system. Given that the latter produces substantially more kWh of generation per kW of capacity (i.e., a higher capacity factor) than the former, this is an obvious flaw.

Multiple, freely available tools are used for estimating solar generation. One of the most common, PVWatts, was developed by the National Renewable Energy Laboratory ("NREL") and is commonly used in regulatory proceedings to provide a first order estimate for solar generation in a given location.[65] PVWatts returned the following generation estimates for towns in several areas of PPL's territory.[66]

Region	**City**	**Fixed Tilt**		**Tracking**	
		kWh / kW	Cap Factor	kWh / kW	Cap Factor
Northeast	Scranton	1,444	16.5%	1,778	20.3%
Susquehanna	Williamsport	1,458	16.6%	1,784	20.4%
Lehigh	Bethlehem	1,544	17.6%	1,900	21.7%
Central	Hazleton	1,493	17.0%	1,832	20.9%
Harrisburg	Harrisburg	1,575	18.0%	1,930	22.0%
Lancaster	Lancaster	1,603	18.3%	1,969	22.5%
PVWatts Avg		**1,520**	**17.3%**	**1,866**	**21.3%**
PPL Assumption	**Unknown**	**2,609**	**29.8%**	**2,609**	**29.8%**

Table 2 - Capacity Factors from PPL Territory

Q58. HOW DO THESE FIGURES COMPARE TO THE COMPANY'S ESTIMATE?

[65] PVWatts is available at https://pvwatts.nrel.gov/pvwatts.php

[66] Estimates used default assumptions for fixed tilt (standard panels, south-facing, 20 degree tilt) and single axis (standard panels, north-south tracker orientation, 0 degree tilt) tracking systems. An inverter load ratio of 1.2 and 1.3 were assumed for fixed-tilt and single axis tracking systems, respectively.

A58. The Company's values are substantially higher than those returned from PVWatts, particularly for fixed-tilt systems. In fact, the Company's 29.8% capacity factor assumption is 72% higher for fixed-tilt systems and 40% higher for single-axis tracking systems than the values derived from PVWatts. There is also no differentiation by project location, despite cities in the Company's territory receiving more or less sun on average over the course of a year. Because the Company's cost-shift methodology scales directly with the amount of solar generation from FTM DG projects, this over-estimate of solar generation serves to increase the apparent cost of the FTM DG projects.

Q59. DID THE COMPANY ATTEMPT TO JUSTIFY ITS USE OF THIS FIGURE?

A59. Yes. The Company stated that the 29.8% capacity factor was "within the range of legitimate applications."[67]

Q60. DO YOU AGREE WITH THIS ASSESSMENT?

A60. It is technically true, but functionally inaccurate. The Company provided a list of projects in its interconnection queue that appear to form the basis of its FTM DG cost shift analysis. In analyzing the 754 projects in this file, six had obviously erroneous data (e.g., two with capacity factor greater than 100%, and one with a capacity factor over 60%, which is not possible with solar technology, and three with capacity factors under 10%, which is not realistic).[68] 400 of the 754 projects in the interconnection queue provided generation data (including the six with invalid assumptions), while 354 provided no estimated generation data.[69]

[67] KML Exhibit -25, JSA III-15.
[68] JSA II-14 CONFIDENTIAL Attachment 1. (Not an exhibit or an attachment to this testimony).
[69] JSA II-14 CONFIDENTIAL Attachment 1. (Not an exhibit or an attachment to this testimony).

Removing these six projects, there were exactly four projects that exceeded the Company's assumed 29.8% capacity factor, and three of these four were submitted on the same day, with the same system size, with the same estimated generation, and with the same expected in service date. If these three applications represented duplicate interconnection requests for the same project, then the Company's assumed generation would be greater than 392 of the 394 projects in the Company's queue that provided valid generation estimates.

Figure 5 below shows the extreme nature of the Company's inaccurate generation assumption. This chart shows a histogram of capacity factors for 748 projects in the Company's interconnection queue with valid data.[70] Of the 394 projects that provided valid generation values, the capacity-weighted capacity factor was 21.0%. Roughly 60% of these projects had capacity factors between 19% and 22%, while 80% had capacity factors between 18% and 23%. Despite this, the Company assumed that all 354 projects that did not provide generation data have a capacity factor of 29.8%. There is no analytical basis for this assumption and it should be rejected.

[70] This excludes the 6 projects with invalid production level estimates.

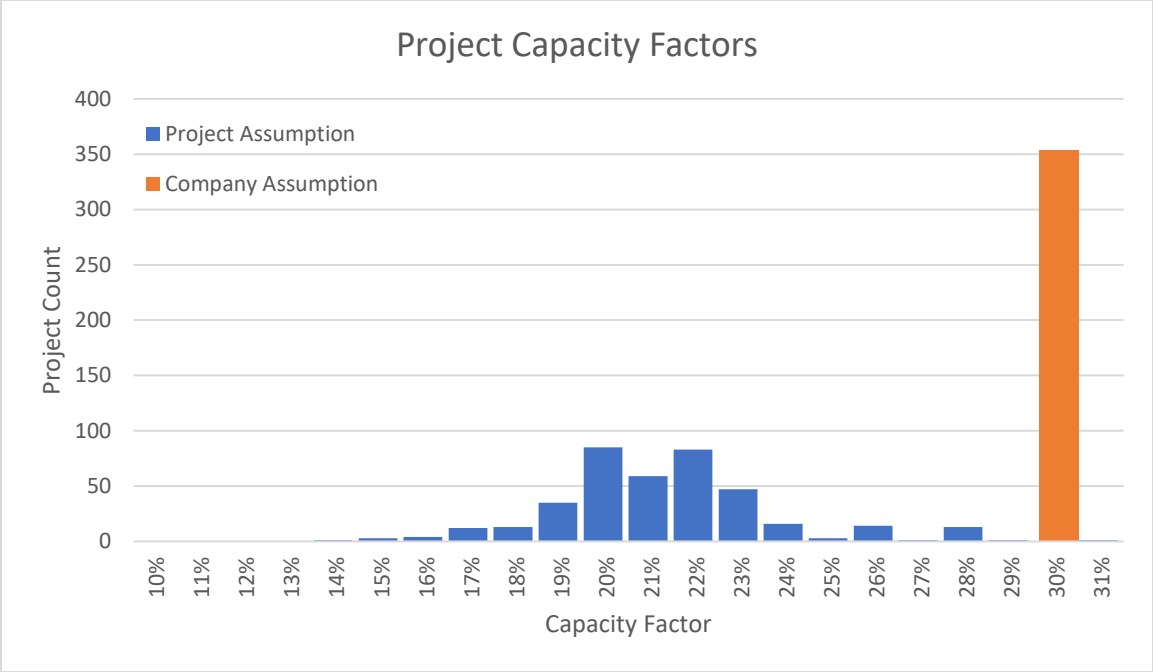

Figure 5 - FTM DG Capacity Factor Assumptions

Q.61. WHAT WOULD THE IMPACT BE IF MORE REALISTIC ASSUMPTIONS HAD BEEN USED FOR THESE PROJECTS?

A61. If the Company had used the capacity-weighted average of the projects that provided generation estimates for the projects that did not provide generation estimates, the total projected generation from FTM DG systems in the data set would have fallen by 17%. This would have a direct impact on the estimated annual cash-out payments and subsequent increase in the PTC under the Company's methodology.

Q62. PLEASE DISCUSS THE THIRD ERROR RELATED TO THE COST OF ENERGY PROCUREMENT.

A62. The third error is the most problematic of all, and on its own renders the entire analysis unusable and entitled to no weight. The Company decided to present its cost-shift analysis in a "all else equal" manner, attempting to "isolate" the impact of FTM DG projects:

> PPL Electric kept all variables constant with the exception of the net metering expense in the GSC-1 reconciliation constant in an effort to isolate the impacts of

the increase in net metering expense on the PTC. Per response to JSA II-9, the Company does not speculate on total costs impacted by potential increases or decreases in demand. The procurements ensure that supply adjusts with demand.[71]

Q63. IS THIS APPROACH REASONABLE?

A63. No. The Company's attempt to isolate the impact of higher FTM DG generation while ignoring the actual impacts of that generation is not methodologically sound. It only captures one side of the coin, increasing the excess generation cashout costs, but not decreasing the energy procurement costs that automatically result from the excess generation. In short, the Company's approach breaks the "energy balance" of the system and results in double-paying for generation that it does not in fact purchase.

Q64. HOW DOES THE COMPANY PRODUCE ITS PROJECTED INCREASE IN THE GSC-1 PTC?

A64. The Company begins by using the inputs that were in effect for the June 1, 2025, PTC calculation.[72] This included values from the March 31, 2024, reconciliation that was used in setting the PTC rate as part of that calculation. The June 1, 2025, PTC calculation assumed an SCI energy procurement expense of $136.9 million, which was based on a specific quantity of energy paid for at the DSP contract rate. The Company then adds to this figure the "updated" NEM expense, which is calculated by multiplying 60 million kWh of FTM DG excess generation d by the then-current PTC.[73]

For the March 2026 reconciliation, this results in additional NEM expenses of $18.1 million for the SCI class. The $18.1 million in NEM expenses is added to the $136.9 million of energy procurement expenses to calculate a new revenue recovery requirement of approximately $155 million for the SCI class. This revenue recovery

[71] KML Exhibit -26, JSA III-16(d).
[72] KML Exhibit -27, JSA III-16(c)(1).
[73] This example uses the Company's 36% cancellation rate workpaper although, as discussed above, these figures actually represent a 0% cancellation rate.

requirement is then applied over the same level of customer sales, resulting in a higher PTC for the next period.

For the March 2027 reconciliation, the Company repeats the process but now adds an additional tranche of FTM DG projects and the corresponding increase in excess generation that is cashed out at the then-current PTC. In March 2027, this adds 391 million kWh in excess generation paid for at a higher PTC, resulting in another $60.1 million in NEM expenses to be recovered in the reconciliation process. Again, the Company holds the assumed energy procurement costs constant at $136.9 million, so now roughly $197 million needs to be recovered from the same level of sales. This drives the PTC up even further.

The process is repeated each year, with ever more excess generation from new FTM DG projects being paid a higher and higher PTC rate. The new NEM expense is added to a constant energy procurement cost, leading to a reinforcing cycle of more excess generation, higher NEM expenses, higher total supply costs, a higher resulting PTC, more excess generation, higher NEM expenses, higher total supply costs, a higher resulting PTC, and so on. The final 2029 reconciliation calculation results in a 2029 PTC of $0.29515/kWh, $0.17401/kWh higher than the 2025 value.

Q65. WHAT IS THE PROBLEM WITH THIS ANALYSIS?

A65. The problem is that the Company adds costs associated with additional FTM DG generation but does not reduce the quantity of energy that is purchased on the DSP contracts by a corresponding amount. This fails to recognize the "zero sum game" nature of energy supply procurement: one does not buy two units of energy to serve one unit of load.

But this is exactly what the Company's methodology assumes. By attempting to "hold all other inputs constant", the Company's calculation purchases two units of energy to serve one unit of load. It pays for a kWh of excess generation from the FTM DG project but also pays for that same kWh on the DSP contract. The result is that the $136.9 million stays constant instead of being decreased by the amount of generation that is supplied to load by FTM DG projects.

This error drives the bulk of the supposed cost-shift found by the Company. Had it properly decremented energy procurement costs based on the reduction in energy purchased on the DSP contracts, the energy procurement cost (which was held constant at $136.9 million) would have fallen each year. This would have reduced the incremental revenue that needed to be collected to fund the excess generation payouts, which would have in turn reduced the PTC each iteration.

Q66. WERE YOU ABLE TO CORRECT THE COMPANY'S CALCULATION TO SEE HOW THE VALUES WOULD CHANGE?

A66. No. The Company's workpapers contained only the hardcoded energy procurement cost value of $136.9 million and did not contain all of the information, such as sales quantities and energy price forecasts, that would be needed to produce a more accurate value. That said, JSA Witness Barnes has developed an analysis in JSA Statement No. 2 that compares the value of excess generation to the PTC that provides a more accurate assessment of what, if any, gap exists between FTM DG excess generation compensation and value.

Q67. PLEASE EXPLAIN THE LAST ERROR IN THE COMPANY'S METHODOLOGY, I.E., FAILING TO INCLUDE BENEFITS FROM EXCESS FTM DG GENERATION.

A67. The last error also stems from the Company's decision to hold all inputs constant, which by definition precludes feedback benefits that would be realized as more FTM DG is added to the Company's system.

PPL is assigned transmission and generation capacity charges by PJM based on the total peak load that it experiences. Transmission costs are assigned by PJM based on a utility's 1CP peak hour, while generation capacity costs are assigned based on the utility's load during the PJM-wide 5CP peak hours that fall on different non-weekend summer days. To the extent that FTM DG systems are producing energy during these hours, they will reduce the costs that are allocated to PPL customers. This will in turn reduce the total generation capacity and transmission revenue that needs to be collected from customers, which, for a given level of sales, will result in lower rates for all customers. Nowhere in PPL's analysis are these benefits accounted for.

Q68. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S FTM DG COST-SHIFT ANALYSIS?

A68. I recommend the PaPUC disregard PPL's cost shift analysis in its entirety as it is methodologically unsound. The top-line estimate of $300 million in cost shift per year is based on a fundamental error that forecasts 100% of projects will be built, despite the unrealistic nature of this assumption. The analysis continues to substantially overstate the amount of generation that can be expected from the projects that do get built by using an unrealistic capacity factor for nearly half of the projects in the interconnection queue.

Next, and most importantly, the Company's decision to perform an "all else equal" analysis that holds energy procurement costs constant while increasing FTM DG generation results in purchasing two units of energy to serve every unit of load. This

fatal flaw cannot be reconciled and renders the results meaningless. Finally, the Company fails to acknowledge the PJM cost allocation benefits that come from FTM DG generation that occur during key hours which determine costs assigned to PPL. This generation will reduce the transmission and generation cost assignment for all PPL's customers, not just CSI customers taking service on DSP contracts.

The combination of these errors results in a substantial overstatement of the gap between the value of FTM DG excess generation and the PTC compensation that is paid for this excess generation. Because of this, the PaPUC should not rely on this analysis when deciding whether or not to require FTM DG customers to take service on GSC-1 or GSC-2.

Q69. DOES THIS CONCLUDE YOUR TESTIMONY?

A69. Yes. However, I reserve the right to file such additional testimony as may be necessary or appropriate.

APPENDIX A – GLOSSARY OF TERMS

AC – Alternating Current

AEC(s) – Alternative Energy Credit(s)

AEPS Act - Alternative Energy Portfolio Standards Act

BTM – Behind The Meter

BTM DG – Behind The Meter Distributed Generation

CCSA – Coalition for Community Access

CIAC – Contributions in Aid of Construction

COSS – Cost of Service Study

CP – Coincident Peak

DG – Distributed Generation

DRIPE - Wholesale Market Price Effect

DSIRE - Database of State Incentives for Renewables and Efficiency

DSP – Default Service Provider

EDC - Electric Distribution Company

EGS – Electric Generation Supplier

FERC – Federal Energy Regulatory Commission

Feeder – an electric line of distribution level voltage

FTM DG – Front of The Meter Distributed Generation

GSC – Generation Service Charge

GSC-1 – the charge applied to residential and selected small commercial/industrial customers who take default service

GSC-2 – the charge applied to customers in the large industrial class who take default service from PPL under rate schedules GS-3, LM-4, LP-5

ICAP – Installed Capacity

IEEE- Institute of Electrical and Electronics Engineers

IRPs – Integrated Resource Plans

JSA – Joint Solar Advocates

kW - kilowatt

LMP – Locational Marginal Price

MRPL – Maximum Registered Peak Load

MW – megawatt

NCP – Non-coincident peak

NEM – Net Energy Metering/Metered

NOAA - National Oceanic and Atmospheric Administration

NoCI – Notice of Customer Intent

NREL – National Renewable Energy Laboratory

NREL SAM - National Renewable Energy Laboratory's System Advisor Model

OATT – Open Access Transmission Tariff

PaPUC – Pennsylvania Public Utility Commission

PPL – PPL Electric Utilities Corporation

PLC – Peak Load Contribution

PTC – Price To Compare

PV- Photovoltaic

RPM – Reliability Pricing Model (PJM)

SCI – Small Commercial and Industrial

SEIA – Solar Energy Industries Association

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	
Coalition For Affordable Utility Services	
And Energy Efficiency in Pennsylvania	Docket Nos.
Office of Small Business Advocate	R-2025-3057164
Brad and Jennifer Woolley	C-2025-3057844
	C-2025-3057889
v.	C-2025-3057946
PPL Electric Utilities Corporation	

VERIFICATION

I, Kevin Lucas, hereby declare that I am the Vice President, Policy Analysis of Solar Energy Industries Association; that, as such, I am authorized to make this verification on their behalf; that the facts set forth in the foregoing Direct Testimony are true and correct to the best of my knowledge, information and belief, and that I make this verification subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Date: December 22, 2025

By: Kevin Lucas

Digitally signed by Kevin Lucas
DN: cn=Kevin Lucas, o=SEIA, ou, email=klucas@seia.org, c=US
Date: 2025.12.18 16:47:13 -05'00'

Kevin Lucas, Vice President, Policy Analysis
Solar Energy Industries Association

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2025-3057164
v.	:	
	:	
PPL Electric Utilities Corporation	:	
	:	

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KML
EXHIBIT-1

KEVIN M. LUCAS

SOLAR ENERGY INDUSTRIES ASSOCIATION

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

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

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

AREAS OF EXPERTISE

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

EDUCATION

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

ACADEMIC HONORS

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

EXPERT WITNESS TESTIMONY

Arizona Corporation Commission

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

Public Utilities Commission of the State of Colorado

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

Public Utilities Commission of the State of Colorado – Cont.

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

Georgia Public Service Commission

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

Illinois Commerce Commission

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

Maryland Public Service Commission

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

Michigan Public Service Commission

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

Public Utility Commission of Nevada

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

North Carolina Utility Commission

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

Pennsylvania Public Utility Commission

- Docket No. R-2025-3054394 – *Citizens' Electric 2025 Rate Case*
    - Advocating against utility proposal to create new definition of demand that is inconsistent with traditional rate regulation; determining avoided cost value of net metered systems in the PJM wholesale market

Public Service Commission of South Carolina

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

Public Utility Commission of Texas

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

Virginia State Corporation Commission

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

KML
EXHIBIT-2

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set IV Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 26, 2025
Docket No. R-2025-3057164

JSA IV-5

Please refer to the Company's most recent Default Service Plan Petition filed in P-2024-3047290 at p. 5 of the Default Service RFP document stating "For the purposes of this RFP, the Default Service Load will be reduced by any net excess generation purchased from net metering (customer generation)…"

a. Please define the term "net excess generation" for the purposes of the statement above. For instance, is "net excess generation" all energy delivered to the grid by a net metering customer, or only the net excess as measured over a monthly billing period or an annual period?
b. Please confirm that this clause was present in the Company's most recent RFP for Default Service supply. If the net excess generation adjustment was not part of the most recent Default Service RFP, please explain why it was omitted.
c. How was net metering net excess generation treated for the purpose of Default Service supply in the Company's previous Default Service Plan?
d. Is the "excess generation" referred to above limited to energy, or does it also include adjustments to capacity components such as generation capacity?
e. Please provide a complete explanation of how net excess generation from net metering customers is applied as an adjustment to Default Service Load. For instance, is the adjustment time differentiated, such as on an hourly basis? Is there a "price" ($/kWh) associated with the excess generation adjustment, or is the adjustment a kWh decrement to Default Service Load?
f. Provide all Documents used, relied upon and/or that support each answer in subparts (a)-(e) above.

PPL Electric Response

a. Net excess generation is the amount of generation produced by a customer-generator in a billing period that exceeds the customer-generator's electric usage.

b. Yes, it was included in the Company's most recent RFP as defined in the RFP Rules.
c. The treatment of net excess generation for DSP V was the same as it is for DSP VI. See page 5 of the DSP V RFP Process and Rules in the DSP V proceeding at Docket No. P-2020-3019356.
d. Excess generation is limited to energy usage only.
e. The net excess generation reduces supplier obligations as part of their fixed price, full-requirements load following contract.
f. See the Alternative Energy Portfolio Standards Act of 2004, Chapter 75, Subchapters A and B of the Commisison's regulations, the DSP VI proceeding at Docket No. P-2024-3047290, and the DSP V proceeding at Docket No. P-2020-3019356.

KML
EXHIBIT-3

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set IV Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 26, 2025
Docket No. R-2025-3057164

JSA IV-4

Please refer to the Company's response to JSA 1-10(b), stating "If NEM customer-generator projects provide output during the 5 coincident peaks ("5CP"), it would reduce PJM capacity cost obligations for all customer classes. However, the Company has not performed a specific study that confirms or quantifies those benefits."

a. If a NEM customer-generator projects provide output during the Company's zonal 5CP hours, would that reduce the allocation of network integration transmission service charges to the customer class in which that NEM customer resides? Please explain in detail.
b. Please explain in detail why NEM output during the 5CP hours would reduce PJM capacity obligations for all customer classes, rather than only for the customer class in which a given NEM customer-generator resides.
c. Provide all Documents used, relied upon and/or that support each answer in subparts (a)-(b) above.

PPL Electric Response

a. No. Customers pay for Network Integration Transmission Service ("NITS") when they take transmission service at PJM. In the PPL zone, this is calculated in part using the PPL formula rate. The PPL formula rate is based on a single zonal peak calculated by PJM during the calendar year. To the extent the NEM customer-generator projects impact that single peak, they would affect the transmission rate paid by all wholesale customers taking transmission service in the PPL zone.
b. To further clarify the response to JSA I-10(b), PJM calculates the load obligation of a given zone, which represents the capacity obligation of that zone as a part of the overall PJM pool obligation. Although PPL Electric does not directly work on this process, the Company's understanding is that NEM output during the 5 CPs would reduce the PPL zone load obligation and thus the

overall share of PJM capacity costs for which all customers in the PPL zone are charged.

c. For (a): PPL Electric formula rate. PJM OATT, Attachment H-8G (https://agreements.pjm.com/oatt/8290).
For (b): PJM Manual 20A (https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.pdf).

KML
EXHIBIT-4

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set IV Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 26, 2025
Docket No. R-2025-3057164

JSA IV-4

Please refer to the Company's response to JSA 1-10(b), stating "If NEM customer-generator projects provide output during the 5 coincident peaks ("5CP"), it would reduce PJM capacity cost obligations for all customer classes. However, the Company has not performed a specific study that confirms or quantifies those benefits."

a. If a NEM customer-generator projects provide output during the Company's zonal 5CP hours, would that reduce the allocation of network integration transmission service charges to the customer class in which that NEM customer resides? Please explain in detail.
b. Please explain in detail why NEM output during the 5CP hours would reduce PJM capacity obligations for all customer classes, rather than only for the customer class in which a given NEM customer-generator resides.
c. Provide all Documents used, relied upon and/or that support each answer in subparts (a)-(b) above.

PPL Electric Response

a. No. Customers pay for Network Integration Transmission Service ("NITS") when they take transmission service at PJM. In the PPL zone, this is calculated in part using the PPL formula rate. The PPL formula rate is based on a single zonal peak calculated by PJM during the calendar year. To the extent the NEM customer-generator projects impact that single peak, they would affect the transmission rate paid by all wholesale customers taking transmission service in the PPL zone.
b. To further clarify the response to JSA I-10(b), PJM calculates the load obligation of a given zone, which represents the capacity obligation of that zone as a part of the overall PJM pool obligation. Although PPL Electric does not directly work on this process, the Company's understanding is that NEM output during the 5 CPs would reduce the PPL zone load obligation and thus the

overall share of PJM capacity costs for which all customers in the PPL zone are charged.

c. For (a): PPL Electric formula rate. PJM OATT, Attachment H-8G (https://agreements.pjm.com/oatt/8290).
For (b): PJM Manual 20A (https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.pdf).

KML
EXHIBIT-5

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-8

Refer to Direct Testimony of Andrew Castanaro, PPL St. No. 15, at 5:14-25.

a. Identify, describe and confirm whether the "nameplate capacity of the generation system" is based on the DC rating of the solar panels or on the AC rating of the inverter.
b. Is it correct that once 12 months of usage is established, the proposed maximum registered peak load ("MRPL") definition will no longer be based on any measure of system rating, and will only be based on the actual power flow from or into PPL's distribution system.
c. If the answer to No. 8(b) is anything other than an unequivocal yes, explain and fully describe your answer and provide all Documents that support, are utilized and/or relied upon in your answer.
d. Is it correct that the MRPL is based on the highest 15-minute period of a given month?
e. If the answer to No. 8(d) is anything other than an unequivocal yes, explain and fully describe your answer and provide all Documents that support, are utilized and/or relied upon in your answer.
f. Is the assignment of customers to the GSC-1 and GSC-2 only performed once per year after the 12-month period ending September 30th occurs for that customer?
g. If the answer to No. 8(f) is anything other than an unequivocal yes, explain and fully describe your answer and confirm if customers would immediately be moved from GSC-1 to GSC-2 if they experience one 15-minute period where their MRPL exceeds 100 kW? Provide all Documents that support, are utilized and/or relied upon in your answer.
h. If a customer is given a preliminary estimate of 110 kW based on the "nameplate capacity" of a system, but is subsequently found to only have a MRPL of 90 kW based on actual power flows, would the customer be automatically reverted to the GSC-1 tariff?

i. If the answer to 8(h) is anything other than an unequivocal no, identify, describe and explain the steps/actions the Company follow to provide notice to the customer, and the steps/actions the customer needs to do to switch to the GSC-1 tariff? Provide all Documents that support, are utilized and/or relied upon in your answer and include any restrictions or time limits on this process, such as a limited window to switch tariffs or minimum stay-outs, etc.

j. Under the assumption that a PPL customer with at least 12 months of billing history and a historic peak demand of 75 kW were to install a 110 kW PV system, is it correct this customer would not be immediately moved to the GSC-2 tariff based on the installation of a 110 kW PV system, but would be classified for GSC-1 or GSC-2 service based on the actual power flow from or into the Company's distribution grid after the PV system installation, if PPL's proposal in this case was adopted by the Commission? If that is not correct, please explain. Provide all Documents that support, are utilized and/or relied upon in your answer.

PPL Electric Response

a. The nameplate capacity of the generation system is determined by the total AC rating of all inverters.

b. The Maximum Registered Peak Load ("MRPL") will be based on the actual power flow from or into PPL Electric's distribution system for the number of months they are online when the annual account analysis for reclassification is performed.

c. The timeframe of actual power flow is based on how long the system has been online when the annual account analysis for reclassification is performed, not necessarily 12 months of actuals.

d. Yes.

e. See Part d.

f. Yes. The reassignment is effective on June 1, based on the prior 12-month period ending September 30.

g. See Part f.

h. The customer would be reclassified based on actual flows during the reclassification period.

i. See Part h.

j. Correct, the customer would not immediately be classified a GSC-2 customer.

KML
EXHIBIT-6

WITNESS: Gregory Olsen
Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 7, 2025
Docket No. R-2025-3057164

JSA I-11

Refer to Direct Testimony of Andrew Castanaro, PPL St. No. 15, at 6:10-11, which states "This current practice fails to reflect the stress that the behind-the-meter generation puts on PPL Electric's distribution system."

a. Identify, describe and define "stress" as it is used in this sentence. Please fully explain and provide all Documents utilized and/or relied upon in your answer.

b. Identify, describe and define "distribution system" as used in this sentence and indicate which components (e.g., line transformers, feeders, substations, etc.), if any, are included in this definition as well as their location. Please fully explain and provide all Documents utilized and/or relied upon in your answer.

c. Identify, describe and explain in detail how behind-the-meter generation puts stress on PPL Electric's distribution system. Please fully explain and provide all Documents utilized and/or relied upon in your answer.

PPL Electric Response

a. Stress refers to the wear and tear on all distribution equipment. Regardless of the direction of power flow, exported generation causes a similar level of wear and tear on distribution system components. However, line transformers often experience greater damage under the same export demand compared to load because differing load profiles can lead to overheating. Overall, there is no significant difference between the impact of load and generation power.

b. The distribution system is defined as any facility below 69 kV required to transport power from the distribution substation

to customers, including local wires, transformers, substations, and other equipment used to deliver electricity to end-use consumers from the high-voltage transmission lines. This equipment is located throughout PPL Electric's distribution system.

c. See Part a. above.

KML
EXHIBIT-7

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 7, 2025
Docket No. R-2025-3057164

JSA I-14	Does PPL believe that a customer's use of the distribution system is independent of the use of all other customers who are served by the same distribution system assets? Explain your answer and provide all Documents utilized and/or relied upon in your answer.
PPL Electric Response	No, PPL Electric does not consider one customer's use of the distribution system as independent from other customers' use. The Company considers customers' information in the aggregate when analyzing the distribution system's assets and impacts.

KML
EXHIBIT-8

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 7, 2025
Docket No. R-2025-3057164

JSA I-15

Does PPL typically build its distribution system assets to serve the maximum demand of individual customers, or does it build its distribution system assets to serve the diversified demand of all customers taking service on those assets? If the answer varies by the type of distribution asset, please answer separately for each type of distribution asset. Explain your answer and provide all Documents utilized and/or relied upon in your answer.

PPL Electric Response

PPL Electric evaluates either maximum demand or diversified demand depending on the customer type. In most cases, the Company assesses each customer's peak diversified demand to determine their contribution to overall circuit loading. However, certain load customers are evaluated using a 100% diversification factor due to the likelihood that all of their equipment could operate simultaneously.

Although the distribution system and its associated assets are planned based on either maximum or diversified demand for load customers, PPL Electric separately analyzes the individual maximum demand of customer-generators to assess their specific impacts on the distribution system, given the likelihood that their generation systems will operate at nameplate capacity.

KML
EXHIBIT-9

WITNESS: Joseph Lookup
Bickey Rimal
Steven W. Wishart

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 7, 2025
Docket No. R-2025-3057164

JSA I-17	If a customer hits their individual peak demand during a 15-minute period in which the distribution system is well below its annual peak (e.g., a weekend morning in the spring), and all distribution assets that are involved in providing power to the individual are below their annual peak values, does PPL believe that this customer is imposing on PPL any incremental costs to provide this service? Explain your answer and provide all Documents utilized and/or relied upon in your answer.
PPL Electric Response	No, in this situation, PPL Electric would not incur costs that are incremental to the costs already incurred by the Company to serve that customer. The necessary assets must be installed to accommodate the customer's peak demand, regardless of when it occurs. PPL Electric cannot predict or control the timing of a customer's peak usage.

KML
EXHIBIT-10

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 7, 2025
Docket No. R-2025-3057164

JSA I-18	For distribution assets located downstream from a substation, are there any distribution assets that are configured to prevent two-way flow of electricity? That is, if a customer-generator is exporting power from its system onto PPL's system, are there any assets that would not be able to accommodate this reverse power flow? If so, please list the types of assets and provide how much/percentage of PPL's existing system is comprised of this type of asset. Explain your answer and provide all Documents utilized and/or relied upon in your answer.
PPL Electric Response	No, PPL Electric does not have any distribution assets downstream of a substation that are configured to prevent two-way power flow. Additionally, PPL Electric conducts Interconnection Impact Reviews ("IIRs") to help ensure that all distribution devices downstream of a substation operate safely and reliably under two-way power flow conditions, which may require the Company to undertake distribution system upgrades.

KML
EXHIBIT-11

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 7, 2025
Docket No. R-2025-3057164

JSA I-20	Do PPL's current interconnection practices and procedures for customer-generators and others, including all forms of distributed energy resources, ensure safe and reliable operation of its distribution system? Explain your answer and provide all Documents utilized and/or relied upon in your answer.
PPL Electric Response	Yes. PPL Electric's interconnection practices and standards are designed to ensure the safe and reliable operation of its distribution system. As part of the interconnection process, PPL Electric identifies and implements system reinforcements necessary to maintain safety and reliability of the system, thereby avoiding excessive or unnecessary upgrades.

KML
EXHIBIT-12

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-10

Identify and describe each component of the GSC-2 credit rate (*e.g.*, generation, transmission, administrative charge) that will be applied to compensate excess generation from net-metered customer generators.

a. Identify, describe and explain the changes to demand charges ($/kW) paid by customer-generators reclassified from GSC-1 to GSC-2 as a result of PPL's proposed change to the definition of maximum registered peak load. Provide all Documents that support, are utilized and/or relied upon in your answer.

PPL Electric Response

The GSC-2 charge components are set forth and described in the Company's retail tariff. See PPL Electric Exhibit GEO-1, pp. 69-70 and 306-09.

See JSA II-10 Attachment 1 for a breakdown of the calculation of the rate paid per kWh for excess compensation for a GS-3 customer with greater than or equal to 100 kW maximum registered peak load based on the Company's proposal.

a. There is no change to the demand charge paid by the customer as a result of this proposal. The demand charge is a distribution charge. This proposal impacts whether the customer pays the GSC-1 or GSC-2 charge.

KML
EXHIBIT-13

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-15

Identify, describe and explain whether, and to what extent, PPL's determination of a non-residential customer's base rate is a function of its voltage level, and/or (ii) its maximum registered peak load. provide all Documents that support, are utilized and/or relied upon in your answer.

PPL Electric Response

Non-residential base rates are determined by the voltage of the customer's service.

- GS-1 – Single Phase Secondary Voltage
- GS-3 – Three Phase Secondary Voltage
- LP-4 – Primary Voltage (customer owns transformation equipment)
- LP-5 – Transmission Voltage (customer owns transformation equipment.

See PPL Electric Exhibit GEO-1.

The Maximum Registered Peak Load ("MRPL") would not be considered when setting a customer's base distribution rate. Rather, the MRPL would be used to determine the customer's default service rate.

KML
EXHIBIT-14

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-16	Identify, describe and explain when and under what circumstances a non-residential customer will be moved from one rate class to another based on the installation of a PV system, regardless of its size. Explain in detail and provide all Documents that support, are utilized and/or relied upon in your answer.
PPL Electric Response	A non-residential customer would only be reassigned to a different rate class if it changes its service voltage. The existence of a PV system has no bearing on a customer's base distribution rate schedule.

KML
EXHIBIT-15

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-17	Identify, describe and explain whether, and to what extent, a PPL's customer's distribution billing kW is a function of (i) maximum registered peak load, (ii) exported power and/or (iii) the amount of power the customer consumes from PPL's electric system. Explain your answer in detail and provide all Documents that support, are utilized and/or relied upon in your answer.
PPL Electric Response	The Maximum Registered Peak Load ("MRPL") is only used to determine a customer's default service classification and rate, not what is used to develop customer distribution billing kW. Exported power and the amount of power consumed also are not used to develop customer distribution billing kW. See PPL Electric Exhibit GEO-1.

KML
EXHIBIT-16

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set III Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 19, 2025
Docket No. R-2025-3057164

JSA III-4	Identify, describe and explain when and under what circumstances a net-metered customer-generator is required by PPL to pay for the entire cost of distribution system upgrades identified by PPL during the interconnection study/facility impact study process. Provide all Documents that support, are utilized and/or relied upon in your answer.
PPL Electric Response	All net-metered customer-generators are required to pay the entire cost of distribution system upgrades identified by PPL Electric during the interconnection study/facility impact study process.

KML
EXHIBIT-17

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set III Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 19, 2025
Docket No. R-2025-3057164

JSA III-12 Refer to the Company's response to JSA I-11, discussing wear and tear on line transformers.

a. Identify, describe, explain and provide all data and information the Company uses to determine how line transformers age as a function of load, degree of load relative to maximum design load, and duration of load. Provide all Documents that support, are utilized and/or relied upon in your answer.
b. Identify, describe and explain whether the relationship between (i) how transformers experience wear and tear and (ii) the degree to which transformer experience wear and tear at different levels of load is non-linear or linear. Provide all Documents that support, are utilized and/or relied upon in your answer.
c. Identify, describe and explain how components of the distribution system other than transformers including, but not limited to, local wires, fuses, switches, etc. experience wear and tear. Provide all Documents that support, are utilized and/or relied upon in your answer.
d. Identify, describe and explain the extent to which components of the distribution system other than transformers including, but not limited to, local wires, fuses, switches, etc. experience wear and tear in the same relationship addressed in the response to No. 12(b) above with respect to transformers. Provide all Documents that support, are utilized and/or relied upon in your answer.
e. If the types of equipment in 12(c)follow different patterns of wear and tear than transformers, identify, describe and those differences. Provide all Documents that support, are utilized and/or relied upon in your answer.
f. Identify, describe and explain if line transformers experience immediate failure if the load exceeds the maximum rated load of the transformer. Provide all Documents that support, are utilized and/or relied upon in your answer.

g. Assume a feeder connected to a substation transformer has customers that in aggregate have a peak demand of 5 MW and a minimum load of 3 MW. Further assume a customer on this feeder installs a 1 MW net metered customer-generator solar system whose excess output feeds onto the feeder and that the only distributed solar system on this feeder is the 1 MW solar system:
    i. Is it correct that in these circumstances, all else being equal, the solar system's excess power flow would cause the load on the substation transformer to decrease and not increase? If that is not the case, please explain in detail the basis for your answer.
    ii. Is it correct that in these circumstances, all else being equal, the solar excess output would reduce the "wear and tear" on the substation transformer due to reduced load. If that is not the case, please explain in detail the basis for your answer.
    iii. Is it correct that PPL's responses to i. and ii. would be the same regardless of whether the distributed solar system is a behind-the-meter system or front-of-meter, distribution-connected system. If that is not the case, please explain in detail the basis for your answer.

PPL Electric Response

a. PPL Electric utilizes IEEE Standard C57.91-2011 to determine how transformers age.

b. As per IEEE Standard C57.91-2011, the relationship between transformer wear and tear and load is non-linear.

c. Non-transformer equipment experiences typical wear and tear as a function of thermal loading. Devices that utilize electrical or mechanical switching components have an expected finite number of operations. Capacitor and voltage regulator operations, for example, are primarily driven by voltage and reactive power fluctuations. Recloser operations are primarily driven by utility switching or established protection schemes

d. Other distribution components—such as conductors, fuses, switches, and regulators—do not follow the same non-linear wear pattern as transformers. Conductors primarily degrade through thermal cycling and environmental exposure, which is largely linear with respect to loading. Fuses experience no progressive wear and fail only upon operation. Switches, voltage regulators, and other in-series devices that have a component of electrical or mechanical switching can experience degradation both from a current flow perspective and a number of operations perspective. The wear and tear of these switching devices is not related to the level of loading but to the cyclical nature of the load.

e. See response to Parts c and d.

f. Transformers may not fail immediately when the thermal rating is exceeded. Immediate failure is a factor of magnitude of overload as well as age and existing wear of the equipment.

g. See below:

   i. Yes, under conditions where the solar system is actively exporting, the load on the substation transformer would decrease.

   ii. A transformer's useful life is determined based on several factors including, but not limited to, thermal loading, age, frequency and magnitudes of faults, environmental conditions such as ambient temperature, gas testing, etc. Per IEEE C57.91-2011, normal life expectancy of a substation transformer is considered to be risk free below each transformer's nameplate rating loading level. Therefore, reduced loading as indicated in the specific scenario provided would not necessarily result in reduced wear and tear that would prolong life expectancy since both loading values were below the nameplate rating.

   iii. Yes.

KML
EXHIBIT-18

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set III Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 19, 2025
Docket No. R-2025-3057164

JSA III-12 Refer to the Company's response to JSA I-11, discussing wear and tear on line transformers.

a. Identify, describe, explain and provide all data and information the Company uses to determine how line transformers age as a function of load, degree of load relative to maximum design load, and duration of load. Provide all Documents that support, are utilized and/or relied upon in your answer.
b. Identify, describe and explain whether the relationship between (i) how transformers experience wear and tear and (ii) the degree to which transformer experience wear and tear at different levels of load is non-linear or linear. Provide all Documents that support, are utilized and/or relied upon in your answer.
c. Identify, describe and explain how components of the distribution system other than transformers including, but not limited to, local wires, fuses, switches, etc. experience wear and tear. Provide all Documents that support, are utilized and/or relied upon in your answer.
d. Identify, describe and explain the extent to which components of the distribution system other than transformers including, but not limited to, local wires, fuses, switches, etc. experience wear and tear in the same relationship addressed in the response to No. 12(b) above with respect to transformers. Provide all Documents that support, are utilized and/or relied upon in your answer.
e. If the types of equipment in 12(c)follow different patterns of wear and tear than transformers, identify, describe and those differences. Provide all Documents that support, are utilized and/or relied upon in your answer.
f. Identify, describe and explain if line transformers experience immediate failure if the load exceeds the maximum rated load of the transformer. Provide all Documents that support, are utilized and/or relied upon in your answer.

g. Assume a feeder connected to a substation transformer has customers that in aggregate have a peak demand of 5 MW and a minimum load of 3 MW. Further assume a customer on this feeder installs a 1 MW net metered customer-generator solar system whose excess output feeds onto the feeder and that the only distributed solar system on this feeder is the 1 MW solar system:
    i. Is it correct that in these circumstances, all else being equal, the solar system's excess power flow would cause the load on the substation transformer to decrease and not increase? If that is not the case, please explain in detail the basis for your answer.
    ii. Is it correct that in these circumstances, all else being equal, the solar excess output would reduce the "wear and tear" on the substation transformer due to reduced load. If that is not the case, please explain in detail the basis for your answer.
    iii. Is it correct that PPL's responses to i. and ii. would be the same regardless of whether the distributed solar system is a behind-the-meter system or front-of-meter, distribution-connected system. If that is not the case, please explain in detail the basis for your answer.

PPL Electric Response

a. PPL Electric utilizes IEEE Standard C57.91-2011 to determine how transformers age.

b. As per IEEE Standard C57.91-2011, the relationship between transformer wear and tear and load is non-linear.

c. Non-transformer equipment experiences typical wear and tear as a function of thermal loading. Devices that utilize electrical or mechanical switching components have an expected finite number of operations. Capacitor and voltage regulator operations, for example, are primarily driven by voltage and reactive power fluctuations. Recloser operations are primarily driven by utility switching or established protection schemes

d. Other distribution components—such as conductors, fuses, switches, and regulators—do not follow the same non-linear wear pattern as transformers. Conductors primarily degrade through thermal cycling and environmental exposure, which is largely linear with respect to loading. Fuses experience no progressive wear and fail only upon operation. Switches, voltage regulators, and other in-series devices that have a component of electrical or mechanical switching can experience degradation both from a current flow perspective and a number of operations perspective. The wear and tear of these switching devices is not related to the level of loading but to the cyclical nature of the load.

e. See response to Parts c and d.

f. Transformers may not fail immediately when the thermal rating is exceeded. Immediate failure is a factor of magnitude of overload as well as age and existing wear of the equipment.

g. See below:

   i. Yes, under conditions where the solar system is actively exporting, the load on the substation transformer would decrease.

   ii. A transformer's useful life is determined based on several factors including, but not limited to, thermal loading, age, frequency and magnitudes of faults, environmental conditions such as ambient temperature, gas testing, etc. Per IEEE C57.91-2011, normal life expectancy of a substation transformer is considered to be risk free below each transformer's nameplate rating loading level. Therefore, reduced loading as indicated in the specific scenario provided would not necessarily result in reduced wear and tear that would prolong life expectancy since both loading values were below the nameplate rating.

   iii. Yes.

KML
EXHIBIT-19

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set III Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 19, 2025
Docket No. R-2025-3057164

JSA III-12 Refer to the Company's response to JSA I-11, discussing wear and tear on line transformers.

a. Identify, describe, explain and provide all data and information the Company uses to determine how line transformers age as a function of load, degree of load relative to maximum design load, and duration of load. Provide all Documents that support, are utilized and/or relied upon in your answer.
b. Identify, describe and explain whether the relationship between (i) how transformers experience wear and tear and (ii) the degree to which transformer experience wear and tear at different levels of load is non-linear or linear. Provide all Documents that support, are utilized and/or relied upon in your answer.
c. Identify, describe and explain how components of the distribution system other than transformers including, but not limited to, local wires, fuses, switches, etc. experience wear and tear. Provide all Documents that support, are utilized and/or relied upon in your answer.
d. Identify, describe and explain the extent to which components of the distribution system other than transformers including, but not limited to, local wires, fuses, switches, etc. experience wear and tear in the same relationship addressed in the response to No. 12(b) above with respect to transformers. Provide all Documents that support, are utilized and/or relied upon in your answer.
e. If the types of equipment in 12(c)follow different patterns of wear and tear than transformers, identify, describe and those differences. Provide all Documents that support, are utilized and/or relied upon in your answer.
f. Identify, describe and explain if line transformers experience immediate failure if the load exceeds the maximum rated load of the transformer. Provide all Documents that support, are utilized and/or relied upon in your answer.

g. Assume a feeder connected to a substation transformer has customers that in aggregate have a peak demand of 5 MW and a minimum load of 3 MW. Further assume a customer on this feeder installs a 1 MW net metered customer-generator solar system whose excess output feeds onto the feeder and that the only distributed solar system on this feeder is the 1 MW solar system:
    i. Is it correct that in these circumstances, all else being equal, the solar system's excess power flow would cause the load on the substation transformer to decrease and not increase? If that is not the case, please explain in detail the basis for your answer.
    ii. Is it correct that in these circumstances, all else being equal, the solar excess output would reduce the "wear and tear" on the substation transformer due to reduced load. If that is not the case, please explain in detail the basis for your answer.
    iii. Is it correct that PPL's responses to i. and ii. would be the same regardless of whether the distributed solar system is a behind-the-meter system or front-of-meter, distribution-connected system. If that is not the case, please explain in detail the basis for your answer.

PPL Electric Response

a. PPL Electric utilizes IEEE Standard C57.91-2011 to determine how transformers age.

b. As per IEEE Standard C57.91-2011, the relationship between transformer wear and tear and load is non-linear.

c. Non-transformer equipment experiences typical wear and tear as a function of thermal loading. Devices that utilize electrical or mechanical switching components have an expected finite number of operations. Capacitor and voltage regulator operations, for example, are primarily driven by voltage and reactive power fluctuations. Recloser operations are primarily driven by utility switching or established protection schemes

d. Other distribution components—such as conductors, fuses, switches, and regulators—do not follow the same non-linear wear pattern as transformers. Conductors primarily degrade through thermal cycling and environmental exposure, which is largely linear with respect to loading. Fuses experience no progressive wear and fail only upon operation. Switches, voltage regulators, and other in-series devices that have a component of electrical or mechanical switching can experience degradation both from a current flow perspective and a number of operations perspective. The wear and tear of these switching devices is not related to the level of loading but to the cyclical nature of the load.

e. See response to Parts c and d.

f. Transformers may not fail immediately when the thermal rating is exceeded. Immediate failure is a factor of magnitude of overload as well as age and existing wear of the equipment.

g. See below:

   i. Yes, under conditions where the solar system is actively exporting, the load on the substation transformer would decrease.

   ii. A transformer's useful life is determined based on several factors including, but not limited to, thermal loading, age, frequency and magnitudes of faults, environmental conditions such as ambient temperature, gas testing, etc. Per IEEE C57.91-2011, normal life expectancy of a substation transformer is considered to be risk free below each transformer's nameplate rating loading level. Therefore, reduced loading as indicated in the specific scenario provided would not necessarily result in reduced wear and tear that would prolong life expectancy since both loading values were below the nameplate rating.

   iii. Yes.

KML
EXHIBIT-20

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set V Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated December 3, 2025
Docket No. R-2025-3057164

JSA V-10

Refer to the Company's response to JSA I-5 and JSA I-18.

a. Identify, describe and explain how many substations on the Company's system currently experience two-way power flows due to the presence of distributed generation systems?
b. If all "no load" NEM customers that have filed an interconnection application were to connect to the Company's system, how many substations would experience two-way power flow?
c. If a "no load" NEM customer wishes to interconnect to the Company's grid, and this interconnection would cause two-way flow at the substation, what substation equipment upgrades might be required as a result of this two-way power flow?
d. Provide all Documents used, relied upon and/or that support your answers to (a) to (c) and all subparts contained therein.

PPL Electric Response

a. There are currently 6 substations experiencing two-way power flow. For the analysis, see JSA V-10 Attachment 1 with the results in Tab 5.
b. If all queued no-load NEM interconnected, 99 substations would experience two-way power flow, and there would be a potential need for 10 new substations. This analysis did not consider the additional net metering applications that are load customers installing generation facilities. See JSA V-10 Attachment 1 with the results in Tab 5.
c. The potential equipment required at a substation to accommodate two-way power flow is: 12kV breakers, high-side (69kV or greater) potential transformers, upgrade relay packages not already scheduled by PPL Electric, 12kV current transformers, upgraded SCADA packages not already scheduled by PPL Electric, and

potential substation footprint and support structure expansion.

d. See JSA V-10 Attachment 1.

KML
EXHIBIT-21

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-8

Refer to Direct Testimony of Andrew Castanaro, PPL St. No. 15, at 5:14-25.

a. Identify, describe and confirm whether the "nameplate capacity of the generation system" is based on the DC rating of the solar panels or on the AC rating of the inverter.
b. Is it correct that once 12 months of usage is established, the proposed maximum registered peak load ("MRPL") definition will no longer be based on any measure of system rating, and will only be based on the actual power flow from or into PPL's distribution system.
c. If the answer to No. 8(b) is anything other than an unequivocal yes, explain and fully describe your answer and provide all Documents that support, are utilized and/or relied upon in your answer.
d. Is it correct that the MRPL is based on the highest 15-minute period of a given month?
e. If the answer to No. 8(d) is anything other than an unequivocal yes, explain and fully describe your answer and provide all Documents that support, are utilized and/or relied upon in your answer.
f. Is the assignment of customers to the GSC-1 and GSC-2 only performed once per year after the 12-month period ending September 30th occurs for that customer?
g. If the answer to No. 8(f) is anything other than an unequivocal yes, explain and fully describe your answer and confirm if customers would immediately be moved from GSC-1 to GSC-2 if they experience one 15-minute period where their MRPL exceeds 100 kW? Provide all Documents that support, are utilized and/or relied upon in your answer.
h. If a customer is given a preliminary estimate of 110 kW based on the "nameplate capacity" of a system, but is subsequently found to only have a MRPL of 90 kW based on actual power flows, would the customer be automatically reverted to the GSC-1 tariff?

i. If the answer to 8(h) is anything other than an unequivocal no, identify, describe and explain the steps/actions the Company follow to provide notice to the customer, and the steps/actions the customer needs to do to switch to the GSC-1 tariff? Provide all Documents that support, are utilized and/or relied upon in your answer and include any restrictions or time limits on this process, such as a limited window to switch tariffs or minimum stay-outs, etc.

j. Under the assumption that a PPL customer with at least 12 months of billing history and a historic peak demand of 75 kW were to install a 110 kW PV system, is it correct this customer would not be immediately moved to the GSC-2 tariff based on the installation of a 110 kW PV system, but would be classified for GSC-1 or GSC-2 service based on the actual power flow from or into the Company's distribution grid after the PV system installation, if PPL's proposal in this case was adopted by the Commission? If that is not correct, please explain. Provide all Documents that support, are utilized and/or relied upon in your answer.

PPL Electric Response

a. The nameplate capacity of the generation system is determined by the total AC rating of all inverters.

b. The Maximum Registered Peak Load ("MRPL") will be based on the actual power flow from or into PPL Electric's distribution system for the number of months they are online when the annual account analysis for reclassification is performed.

c. The timeframe of actual power flow is based on how long the system has been online when the annual account analysis for reclassification is performed, not necessarily 12 months of actuals.

d. Yes.

e. See Part d.

f. Yes. The reassignment is effective on June 1, based on the prior 12-month period ending September 30.

g. See Part f.

h. The customer would be reclassified based on actual flows during the reclassification period.

i. See Part h.

j. Correct, the customer would not immediately be classified a GSC-2 customer.

KML
EXHIBIT-22

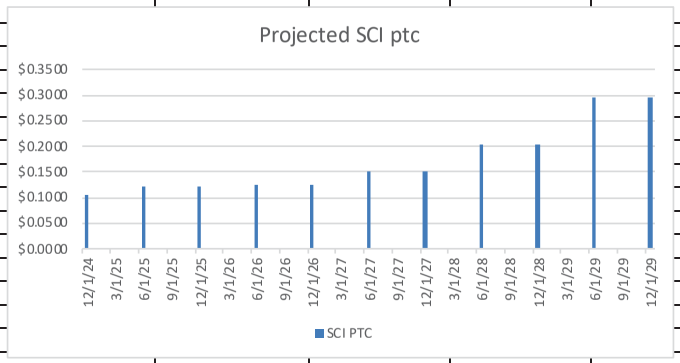
2024	
Cashout goes out 5/31/24	Excess generation 6/1/23 - 5/31/24
Reconciled 3/31/24	Net metering expenses April 2023 - March 2024
Half of reconciliation hits 6/1/24	
Other half hits 12/1/24	
2025	
Cashout goes out 5/31/25	Excess generation 6/1/24 - 5/31/25
Reconciled 3/31/25	Net metering expenses April 2024 - March 2025
Half of reconciliation hits 6/1/25	
Other half hits 12/1/25	
2026	
Cashout goes out 5/31/26	Excess generation 6/1/25 - 5/31/26
Reconciled 3/31/26	Net metering expenses April 2025 - March 2026
Half of reconciliation hits 6/1/26	
Other half hits 12/1/26	

PROJECTED:	12/1/24	6/1/25	12/1/25	6/1/26	12/1/26	6/1/27	12/1/27	6/1/28	12/1/28	6/1/29	12/1/29
SCI PTC	$ 0.10446	0.12114	$ 0.12114	$ 0.12575	$ 0.12575	$ 0.15067	$ 0.15067	$ 0.20474	$ 0.20474	$ 0.29515	$ 0.29515

PROJECTED:	2024	2025	2026	2027	2028	2029
SCI Net Metering Expense[1]	$ 10,350,518	$ 10,841,474	$ 7,292,672	$ 49,287,057	$ 140,441,077	$ 292,867,083

[1] Net Metering expense reflected in each SCI PTC is 1/2 of the amount filed in the March GSC-1 reconciliation, includes expenses from April - March of year (ex. in June '24, the PTC included 1/2 the reconciliation amount for the GSC-1 reconciliation filed in March '24, which included net metering expenses from April '23-March '24)

24.38%
376%



		Total	SCI Only(1)	
	Projected 2025 kWh Bank w/ Cancellation Rate ~36%	49,842,515	17,444,880	
	Projected 2026 kWh Bank w/ Cancellation Rate ~36%	172,008,146	60,202,851	
	Projected 2027 kWh Bank w/ Cancellation Rate ~36%	1,119,886,777	391,960,372	
	Projected 2028 kWh Bank w/ Cancellation Rate ~36%	2,663,225,657	932,128,980	
	Projected 2029 kWh Bank w/ Cancellation Rate ~36%	4,087,014,528	1,430,455,085	
	Percentage of SCI Load in Queue	35%		

(1) SCI accounts for roughly 38% of new service applications for solar (GS3) and the other are LP4 according to the Interconnections team; but these are smaller applications than LP-4, so adjusting to 35% of total kWh (estimate) per Micah Clarke (Distribution Planning)

Year of Reconciliation/Cashout:	2024	2025	2026	2027	2028	2029
SCI Excess kWh for MGs (kWh Cashed Out)			60,202,851	391,960,372	932,128,980	1,430,455,085
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114	$ 0.12575	$ 0.15067	$ 0.20474
SCI Net Metering Expense from MGs			$ 7,292,672	$ 49,287,057	$ 140,441,077	$ 292,867,083
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 18,134,146	$ 60,128,531	$ 151,282,551	$ 303,708,557
	^Actual expense	*^Actual expense*				

NOTES:
The amount of the net metering expense that is included in the reconciliation is only through March of a given year and the cashout kWh is through May of that same year, so there
Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

PTC at 12/1/30
$ 0.29515

<-- Updated 8/20/25

<--cashout amount to be reflected in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each column y

: is some estimation happening here with timing

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/29 & 12/1/29

1	Average Full Requirements Price	$ 0.08064	(1)
2	Times portion of Small Commerical and Industrial Load	100.00%	
3	Total Weighted Full Requirements Price	$ 0.08064	
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*	1.062699	
5	Block and Full Requirements Price adjusted for GRT	$ 0.08570	
6	E Factor Rate	$ 0.16408	(2)
7	Administrative Charges Rate	$ 0.00311	
8	Merchant Function Charge (MFC) Rate	$ 0.00019	
9	Subtotal (Line 6 + Line 7 + Line 8)	$ 0.16738	
10	Multiplied by (1/(1-GRT))	1.062699	
11	(E Factor + Admin Charges + MFC) x GRT	$ 0.177875	
12	Generation Supply Charge (Line 5 + Line 11)	$ 0.26357	
13	Transmission Service Charge (TSC)	$ 0.03158	(3),(5)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	$ 0.00000	(4)
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	$ 0.29515	

Note: Data may not total due to rounding.

(1)	The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.
(2)	Represents an under-collection of April 2023 through March 2024 actual revenue, which will be collected over 12 months.
(3)	The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.
(4)	The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.
(5)	TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. LP4 transmission customers receive a demand charge of $12.080/kW.

Schedule 1

PPL ELECTRIC UTILITIES CORPORATION
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECONCILIATION
Report for the Period April 1, 2028 through March 31, 2029

Line No.		(A) Total	(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470	691,963,798	151,681,672	
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851	654,715,616	136,851,235	
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291	3,449,574	(22,283)	
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	305,809,165	2,100,608	303,708,557	<-- Linked to Net Metering Expense
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292	1,027,846	225,446	
	Total Expenses to Recover	1,102,056,599	661,293,644	440,762,955	
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(258,411,129)	30,670,154	(289,081,283)	
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707	2,472,504	433,203	
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (255,505,422)	$ 33,142,658	$ (288,648,080)	
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)	(1,894,279)	(5,306,664)	
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (262,706,365)	$ 31,248,379	$ (293,954,744)	
	Amount Recovered in Rate 6/1		$ 15,624,190	$ (146,977,372)	
	Amount Recovered in Rate 12/1		$ 15,624,190	$ (146,977,372)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/28 & 12/1/28

1	Average Full Requirements Price	$ 0.08064	(1)
2	Times portion of Small Commerical and Industrial Load	100.00%	
3	Total Weighted Full Requirements Price	$ 0.08064	
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*	1.062699	
5	Block and Full Requirements Price adjusted for GRT	$ 0.08570	
6	E Factor Rate	$ 0.07900	(2)
7	Administrative Charges Rate	$ 0.00311	
8	Merchant Function Charge (MFC) Rate	$ 0.00019	
9	Subtotal (Line 6 + Line 7 + Line 8)	$ 0.08230	
10	Multiplied by (1/(1-GRT))	1.062699	
11	(E Factor + Admin Charges + MFC) x GRT	$ 0.087460	
12	Generation Supply Charge (Line 5 + Line 11)	$ 0.17316	
13	Transmission Service Charge (TSC)	$ 0.03158	(3),(5)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	$ 0.00000	(4)
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	$ 0.20474	

Note: Data may not total due to rounding.

(1)	The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.
(2)	Represents an under-collection of April 2023 through March 2024 actual revenue, which will be collected over 12 months.
(3)	The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.
(4)	The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.
(5)	TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. LP4 transmission customers receive a demand charge of $12.080/kW.

Schedule 1

PPL ELECTRIC UTILITIES CORPORATION
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECONCILIATION
Report for the Period April 1, 2027 through March 31, 2028

Line No.		(A) Total	(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470	691,963,798	151,681,672	
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851	654,715,616	136,851,235	
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291	3,449,574	(22,283)	
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	153,383,159	2,100,608	151,282,551	<-- Linked to Net Metering Expense
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292	1,027,846	225,446	
	Total Expenses to Recover	949,630,593	661,293,644	288,336,949	
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(105,985,123)	30,670,154	(136,655,277)	
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707	2,472,504	433,203	
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (103,079,416)	$ 33,142,658	$ (136,222,074)	
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)	(1,894,279)	(5,306,664)	
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (110,280,359)	$ 31,248,379	$ (141,528,738)	
	Amount Recovered in Rate 6/1		$ 15,624,190	$ (70,764,369)	
	Amount Recovered in Rate 12/1		$ 15,624,190	$ (70,764,369)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/27 & 12/1/27

1	Average Full Requirements Price	$ 0.08064	(1)	
2	Times portion of Small Commerical and Industrial Load	100.00%		
3	Total Weighted Full Requirements Price	$ 0.08064		
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*	1.062699		
5	Block and Full Requirements Price adjusted for GRT	$ 0.08570		
6	E Factor Rate	$ 0.02812	(2)	
7	Administrative Charges Rate	$ 0.00311		
8	Merchant Function Charge (MFC) Rate	$ 0.00019		
9	Subtotal (Line 6 + Line 7 + Line 8)	$ 0.03142		
10	Multiplied by (1/(1-GRT))	1.062699		
11	(E Factor + Admin Charges + MFC) x GRT	$ 0.033390		
				ROUNDING
12	Generation Supply Charge (Line 5 + Line 11)	$ 0.11909		$ 0.00001
13	Transmission Service Charge (TSC)	$ 0.03158	(3),(5)	
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	$ 0.00000	(4)	
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	$ 0.15067		

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which will be collected over 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. LP4 transmission customers receive a demand charge of $12.080/kW.

Schedule 1

PPL ELECTRIC UTILITIES CORPORATION
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECONCILIATION
Report for the Period April 1, 2026 through March 31, 2027

Line No.		(A) Total	(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470	691,963,798	151,681,672	
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851	654,715,616	136,851,235	
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291	3,449,574	(22,283)	
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	62,229,139	2,100,608	60,128,531	<-- Linked to Net Metering Expense
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292	1,027,846	225,446	
	Total Expenses to Recover	858,476,573	661,293,644	197,182,929	
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(14,831,103)	30,670,154	(45,501,257)	
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707	2,472,504	433,203	
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (11,925,396)	$ 33,142,658	$ (45,068,054)	
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)	(1,894,279)	(5,306,664)	
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (19,126,339)	$ 31,248,379	$ (50,374,718)	
	Amount Recovered in Rate 6/1		$ 15,624,190	$ (25,187,359)	
	Amount Recovered in Rate 12/1		$ 15,624,190	$ (25,187,359)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/26 & 12/1/26

1	Average Full Requirements Price	$ 0.08064	(1)		
2	Times portion of Small Commerical and Industrial Load	100.00%			
3	Total Weighted Full Requirements Price	$ 0.08064			
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*	1.062699			
5	Block and Full Requirements Price adjusted for GRT	$ 0.08570			
6	E Factor Rate	$ 0.00468	(2)		
7	Administrative Charges Rate	$ 0.00311			
8	Merchant Function Charge (MFC) Rate	$ 0.00019			
9	Subtotal (Line 6 + Line 7 + Line 8)	$ 0.00798			
10	Multiplied by (1/(1-GRT))	1.062699			
11	(E Factor + Admin Charges + MFC) x GRT	$ 0.00848			
					ROUNDING
12	Generation Supply Charge (Line 5 + Line 11)	$ 0.09417			$ 0.00001
13	Transmission Service Charge (TSC)	$ 0.03158	(3),(5)		
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	$ 0.00000	(4)		
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	$ 0.12575			

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which will be collected over 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. LP4 transmission customers receive a demand charge of $12.080/kW.

Schedule 1

PPL ELECTRIC UTILITIES CORPORATION
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECONCILIATION
Report for the Period April 1, 2025 through March 31, 2026

Line No.		(A) Total	(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470	691,963,798	151,681,672	
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851	654,715,616	136,851,235	
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291	3,449,574	(22,283)	
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	20,234,754	2,100,608	18,134,146	<-- Linked to Net Metering Expense
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292	1,027,846	225,446	
	Total Expenses to Recover	816,482,188	661,293,644	155,188,544	
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	27,163,282	30,670,154	(3,506,872)	
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707	2,472,504	433,203	
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 30,068,989	$ 33,142,658	$ (3,073,669)	
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)	(1,894,279)	(5,306,664)	
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 22,868,046	$ 31,248,379	$ (8,380,333)	
	Amount Recovered in Rate 6/1		$ 15,624,190	$ (4,190,167)	
	Amount Recovered in Rate 12/1		$ 15,624,190	$ (4,190,167)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/25 (ACTUAL) & 12/1/25 (ASSUMED)

1	Average Full Requirements Price	$ 0.08064	(1)		
2	Times portion of Small Commerical and Industrial Load	100.00%			
3	Total Weighted Full Requirements Price	$ 0.08064			
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*	1.062699			
5	Block and Full Requirements Price adjusted for GRT	$ 0.08570			
6	E Factor Rate	$ 0.00034	(2)		
7	Administrative Charges Rate	$ 0.00311			
8	Merchant Function Charge (MFC) Rate	$ 0.00019			
9	Subtotal (Line 6 + Line 7 + Line 8)	$ 0.00364			
10	Multiplied by (1/(1-GRT))	1.062699			
11	(E Factor + Admin Charges + MFC) x GRT	$ 0.00387			
					ROUNDING
12	Generation Supply Charge (Line 5 + Line 11)	$ 0.08956			$ 0.00001
13	Transmission Service Charge (TSC)	$ 0.03158	(3),(5)		
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	$ 0.00000	(4)		
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	$ 0.12114			

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which will be collected over 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. LP4 transmission customers receive a demand charge of $12.080/kW.

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Period: 6/01/2025 through 11/30/2025
ACTUAL

1	Average Full Requirements Price	$ 0.08064	(1)		
2	Times portion of Small Commerical and Industrial Load	100.00%			
3	Total Weighted Full Requirements Price	$ 0.08064			
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*	1.062699			
5	Block and Full Requirements Price adjusted for GRT	$ 0.08570			
6	E Factor Rate	$ 0.00034	(2)		0%
7	Administrative Charges Rate	$ 0.00311			
8	Merchant Function Charge (MFC) Rate	$ 0.00019			
9	Subtotal (Line 6 + Line 7 + Line 8)	$ 0.00364			
10	Multiplied by (1/(1-GRT))	1.062699			
11	(E Factor + Admin Charges + MFC) x GRT	$ 0.00387			
					ROUNDING
12	Generation Supply Charge (Line 5 + Line 11)	$ 0.08956			$ 0.00001
13	Transmission Service Charge (TSC)	$ 0.03158	(3),(5)		
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	$ 0.00000	(4)		
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	$ 0.12114			

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which will be collected over 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. LP4 transmission customers receive a demand charge of $12.080/kW.

Schedule 1

PPL ELECTRIC UTILITIES CORPORATION
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECONCILIATION
Report for the Period April 1, 2024 through March 31, 2025

Line No.		(A) Total	(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	706,417,743	590,614,561	115,803,182
2	Energy Procurement (Schedule 2, Line 2A, Column M)	685,698,006	576,751,936	108,946,070
	PJM Expenses (Schedule 2, Line 2B, Column M)	1,280,073	1,583,491	(303,418)
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	10,739,509	1,782,496	8,957,013
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,033,360	859,444	173,916
	Total Expenses to Recover	698,750,948	580,977,367	117,773,581
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	7,666,795	9,637,194	(1,970,399)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	434,063	679,147	(245,084)
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 8,100,858	$ 10,316,341	$ (2,215,483)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	8,208,302	6,603,351	1,604,951
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 16,309,160	$ 16,919,692	$ (610,532)
	Amount Recovered in Rate 6/1		$ 8,459,846	$ (305,266)
	Amount Recovered in Rate 12/1		$ 8,459,846	$ (305,266)

PPL ELECTRIC UTILITIES CORPORATION
TRANSMISSION SERVICE CHARGE RECONCILIATION
Report For The Period April 1, 2024 to March 31, 2025

Line No.		Total	Residential	Small Commercial & Industrial	Large Commercial & Industrial - Primary	Large Commercial & Industrial - Transmission
1	Actual Transmission Service Charge					
	(Schedule 2, Column M, Lines 1, 6, 10 & 1	$ 250,154,035	$ 208,504,605	$ 37,206,527	$ 2,780,224	$ 1,662,679
2	Actual PJM-Billed Transmission Service Expenses					
	(Schedule 2, Column M, Lines 2, 7, 11 & 15)	251,907,507	207,328,577	40,532,404	3,278,142	768,384
3	Actual PJM Costs Directly Assigned					
	(Schedule 2, Column M, Line 3)	14,109,161	14,109,161	-	-	-
4	Actual Net Metering Expenses					
	(Schedule 2, Column M, Lines 4, 8, 12 & 16)	4,400,782	619,692	1,884,461	1,896,629	-
5	Over/(Under) Collection					
	(Schedule 2, Column M, Lines 5, 9, 13 & 17)	(20,263,415)	(13,552,825)	(5,210,338)	(2,394,547)	894,295
5a	Revenue Adj. - Susquehanna Nuclear, LLC [1]	0	863,109	189,895	22,112	(1,075,116)
5b	Over/(Under) Collection					
	(Line 5 + Line 5a)	(20,263,415)	(12,689,716)	(5,020,443)	(2,372,435)	(180,821)
6	Interest on Over/(Under) Collection					
	(Schedule 5, Line 14, Columns D, F, H, J & L)	(1,158,586)	(760,316)	(267,696)	(117,093)	(13,481)
6A	Interim Rate Filing [2]	18,812,700	15,779,145	2,410,452	897,977	(274,874)
7	Over/(Under) Collection plus Interest (Excluding GRT) (Line 5b plus L	(2,609,301)	2,329,113	(2,877,687)	(1,591,551)	(469,176)
8	Remaining E-Factor Balance (Schedule 3, Line 14, Columns B, D, F	(5,728,790)	(3,480,116)	(630,444)	(535,722)	(1,082,508)
9	Over/(Under) Collection (Excluding GRT) (Line 7 plus Line 8)	$ (8,338,091)	$ (1,151,003)	$ (3,508,131)	$ (2,127,273)	$ (1,551,684)

(1) Represents dollars paid by Susquehanna Nuclear, LLC for backup service related to a behind the meter data center. The adjustment was recorded in the GSC and TSC riders in May of 2024.

(2) Represents the under-collection, including applicable interest, at September 30, 2024, as set forth on Schedule A, Line 4A of the Company's October 30, 2024 rate filing at Docket No. M-2024-3051913.

PPL ELECTRIC UTILITIES CORPORATION
COMPUTATION OF PROPOSED TRANSMISSION SERVICE CHARGE
COMPUTATION PERIOD: JUNE 1, 2025 THROUGH NOVEMBER 30, 2025

Line No.		Total	Residential	Small Commercial & Industrial	Large Commercial & Industrial - Primary	Large Commercial & Industrial - Transmission	
1	Transmission Service Charge		(A)	(A)	(B)	(B)	
2	TCd = Total Demand-related Portion of Projected PJM-Billed Transmission Service Expenses (Schedule B)	$ 135,974,385	$ 109,459,380	$ 23,142,840	$ 3,045,826	$ 326,339	
3	TCe = Total Energy-related Portion of Projected PJM-Billed Transmission Service Expenses (Schedule B)	679,203	679,203	-	-	-	
3A	Total Directly Assignable PJM Expenses - Residential only (Schedule B-1)	6,488,889	6,488,889	-	-	-	
3B	Net Metering Expenses (Schedule B)	1,166,436	-	335,134	831,302	-	
4	E = Experienced Net Over/(Under) Collections, Including Interest and Audit Adjustment (C), Net Prior Period Remaining Balance	(8,338,091)	(1,151,003) C.1	(3,508,131) C.2	(2,127,273) C.3	(1,551,684) C.4	
		-		-	-	-	
5	Net Over(Under) Collection Amount	(8,338,091)	(1,151,003)	(3,508,131)	(2,127,273)	(1,551,684)	
6	Total Amount to be Recovered (Line 2 plus Line 3 plus Line 3A plus Line 3B less Line 5)	$ 152,647,004	$ 117,778,475	$ 26,986,105	$ 6,004,401	$ 1,878,023	
7	Total Amount to be Recovered, Including MFC (Line 6 times MFC)	$ 155,494,198	$ 120,563,465	$ 27,048,308	$ 6,004,401	$ 1,878,023	
8	S = Projected Total Retail KWH Sales to Customers	4,951,994,998	3,853,968,201 A1.1	910,091,326 A2.1	100,207,675 A3.1	87,727,796 A3.2	
9	Billing Demand kW				298,874 E.6		
10	Peak Load Contribution (MW)					70.8 E.1 x 12	
11	Merchant Function Charge Factor (MFC)						
	Residential	1/(1 - .0231) =	1.023646				
	Small Commercial & Industrial	1/(1 - .0023) =		1.002305			
12	1 / (1 - T) = (T = 5.9% Gross Receipts Tax)	x 1.062699					
13	TSC = Transmission Service Charge ($/ KWH)						
	Energy Rate ($/KWH) (w/o GRT)		$ 0.03128	$ 0.02972	$ -	$ -	
	Demand Rate ($/kW) (w/o GRT)				$ 20.090	$ 26.526	
	Energy Rate ($/KWH) (w/ GRT)		$ 0.03324	$ 0.03158	$ -	$ -	
	Demand Rate ($/kW) (w/ GRT)				$ 21.350	$ 28.189	

(A) TSC=[TCe/S + TCd/S - E/S] x 1/(1-T)

(B) TSC=TSCd + TSCe
TSCd=[TCd/D] x 1/(1-T)
TSCe=[TCe/S-E/S] x 1/(1-T)

(C) Schedule 1 of the Transmission Service Charge Reconciliation Report

(D) In accordance with the Commission's approval of PPL Electric's Default Service Program and Procurement Plan for the Period June 1, 2025 through May 31, 2029 at Docket No. P-2024-3047290, PPL Electric is filing a new TSC to be effective for the 6-month period of June 1, 2025 through November 30, 2025. The subsequent price period will be December 1, 2025 through November 30, 2026, for a 12-month period.

Schedule A

KML
EXHIBIT-23

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 7, 2025
Docket No. R-2025-3057164

JSA I-26

Refer to Direct Testimony of Andrew Castanaro, PPL St. No. 15, at 7:3-7 and PPL Electric Exhibits AC-1 through AC-3.

a. Identify, describe and explain in detail the assumptions and data inputs used to determine the "SCI Excess kWh for MGs (kWh Cashed Out)" values listed in PPL Electric Exhibit AC-1 through AC-3. Provide all Documents utilized and/or relied upon in your answer.

b. Are the "SCI Excess kWh for MGs (kWh Cashed Out)" values listed in PPL Electric Exhibit AC-1 4x the values listed in PPL Electric Exhibit AC-3?

c. If the answer to 27(b) is yes, does this mean that PPL Electric Exhibit AC-1 assumes a 0% cancellation rate for interconnection projects? Explain your answer in detail and provide all Documents utilized and/or relied upon in your answer.

d. Identify, describe and explain whether the "Incremental SCI Net Metering Expense" values in PPL Electric Exhibits AC-1 through AC-3 are annual values, or whether they are cumulative from 2026. Explain your answer in detail and provide all Documents utilized and/or relied upon in your answer.

e. Confirm and explain if the difference between the values for "Total Estimated SCI Net Metering Expense" and "Incremental SCI Net Metering Expense" for 2026, 2027, 2028, and 2029 as shown in PPL Electric Exhibits AC-1 through AC-3 is $10,841,474 is equal to the 2025 "Total Estimated SCI Net Metering Expense" in each Exhibit. Explain your answer in detail and provide all Documents utilized and/or relied upon in your answer.

f. If the values in response to 27(d) are annual, what is the purpose of showing the “Total Estimated SCI Net Metering Expense”, which is the sum of the 2025 expense and the expense in each year of 2026/2027/2028/2029? Explain your answer in detail and provide all Documents utilized and/or relied upon in your answer.

g. Identify, describe and explain whether the “SCI Excess kWh for MGs (kWh Cashed Out)” values are annual or cumulative. Explain your answers in detail and provide all Documents utilized and/or relied on in your answer.

h. Identify, describe and provide the number of customers in PPL’s Small C&I class, historical and projected, from 2020-2050. Provide all Documents utilized and/or relied upon in your answer.

i. Identify, describe and provide PPL’s assumptions and the underlying justification for them regarding the number and total MWs of net-metered projects proposed annually. Provide all Documents utilized and/or relied upon in your answer.

j. Identify, describe and provide in detail PPL’s methodology to project excess kWh per year given the assumed number of MWs in operation each year. Provide all Documents utilized and/or relied upon in your answer.

k. If solar generation profiles were used in the calculation to project excess kWh per year given the assumed number of MWs in operation each year, provide them.

l. Identify, describe and explain PPL’s reasons for selecting project cancellation rates of 36%, 50%, and 75%? Provide all Documents utilized and/or relied upon in your answer.

m. Identify, describe and explain the averaged cancellation rates PPL’s interconnection team has experienced on an annual basis between 2020 and 2025. Provide all Documents utilized and/or relied upon in your answer.

n. Identify, describe and explain PPL's estimation process referenced in the note at the bottom of each exhibit: "The amount of the net metering expense that is included in the reconciliation is only through March of a given year and the cashout kWh is through May of that same year, so some estimation is necessary due to timing Utilization Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation." Provide all Documents utilized and/or relied upon in your answer.

PPL Electric Response

a. See response to OCA I-1 and PPL Electric St. No. 15, pp. 6-8.

b. Yes.

c. No, the assumed cancellation rate in PPL Electric Exhibit AC-1 is 36% of the kWh used in the analysis.

d. The "Incremental SCI Net Metering Expense" is the amount of net metering expense anticipated to be added to the Company's current net metering expense of $10,841,474, which is provided in its 2025 Transmission Service Charge ("TSC") and Generation Supply Charge ("GSC") reconciliation filings, based on the additional merchant generator kWh forecasted to be online in each year. The kWh amount provided is cumulative year-over-year, as the assumption is that once the systems come online, they will continue to operate through 2030.

   For clarification, the 715,227,542 kWh provided for 2029 is the total kWh anticipated to come online by 2029 related to merchant generators. The $113,704,729 "Incremental SCI Net Metering Expense" for 2029 is the cost of that generation based on the forecasted Price-To-Compare at that time. This cost is added to the Company's current net metering expense of $10,841,474 to get the $124,546,203 of "Total Estimated SCI Net Metering Expense" for 2029.

e. See response to part d and OCA-I-1 Attachment 14-16 for the workpapers supporting this explanation.

f. See response to Part d.

g. See response to Part d and OCA-I-1 Attachment 14-16 for the workpapers supporting this explanation.

h. See JSA I-26 Attachment 1. PPL Electric does not have projections beyond 2030.

i. PPL Electric based the annual interconnected “no-load" Distributed Energy Resources (DER) net-metering MW forecast on existing applications only and leveraging “actual” projected in-service dates when available. If no in-service date was available, PPL Electric projected a 3-year in-service date from the application received date. This 3-year time frame was selected based on current trends of interconnection lead times to have a conservative approach of when these projects will be active.

j. See JSA I-26 Part i.

The model uses the kWh values provided by the developer when available; otherwise, it estimates energy output by multiplying the Alternating Current (AC) MW nameplate capacity of each application by 2,609, which represents the standard annual hours of sunlight.

k. Solar generation profiles were not used in the calculation of the annual kWh projections.

l. The 36% reflected the Company’s cancellation rate at the time that the analysis was performed. The Company selected 50% and 75% to provide scenarios under which more projects would cancel.

m. PPL Electric does not have cancellation data for Net Energy Metering applications or projects for the years 2020 and 2021. The annual and total average cancellation rates can be found in JSA I-23 Attachment I, Tab 1 and is incorporating new data as of November 12, 2025.

n. PPL Electric files its TSC and GSC reconciliations in April each year for the prior April – March period which includes

the actual net metering expense for April through March. The reconciliation is then included in the TSC and GSC rates filed by May 1st to become effective June 1st (note that 50% of the GSC reconciliation amount is included in the June 1st GSC rate filing and the other 50% is included in the December 1st GSC rate filing).

However, the annual cashout for excess generation for net metering customers occurs on May 31st of each year. In order to complete this analysis, the expected cash out anticipated as of May 31st of each year for these merchant generator customers was included in the reconciliation filed for the prior April – March period so that the increased net metering expense would be reflected in the GSC rate as a means to estimate the impact of the increased net metering expense on the Price-To-Compare. This means that generation that occurred in April and May is included in the reconciliation of net metering expense.

KML
EXHIBIT-24

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set III Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 19, 2025
Docket No. R-2025-3057164

JSA III-15

Refer to the Company's response to JSA I-26(j), which describes the Company's method of estimating solar generation from "no-load" DERs. In this method, the Company multiplied the AC MW by 2,609, "which represents the standard annual hours of sunlight."

a. Please provide the source for the use of 2,609 hours representing the standard annual hours of sunlight. Provide all Documents that support, are utilized and/or relied upon in your answer.
b. Please confirm whether PPL's referenced calculation produces an AC capacity factor of approximately 29.8% and whether this capacity factor is the solar system capacity factor typically expected in PPL's service territory. Provide all Documents that support, are utilized and/or relied upon in your answer.
c. Please provide the percentage of "no-load" solar facilities that have applied for interconnection that are fixed-tilt configurations, and the percentage that are single-axis tracking configurations. Provide all Documents that support, are utilized and/or relied upon in your answer.

PPL Electric Response

a. The annual hours of sunlight are based on data from National Oceanic and Atmospheric Administration ("NOAA").
b. This would produce a capacity factor of 29.78%. Using the data from JSA II-14 CONFIDENTIAL Attachment 1, this capacity factor is within the range of legitimate applications.
c. PPL Electric does not track panel configuration.

KML
EXHIBIT-25

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set III Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 19, 2025
Docket No. R-2025-3057164

JSA III-15

Refer to the Company's response to JSA I-26(j), which describes the Company's method of estimating solar generation from "no-load" DERs. In this method, the Company multiplied the AC MW by 2,609, "which represents the standard annual hours of sunlight."

a. Please provide the source for the use of 2,609 hours representing the standard annual hours of sunlight. Provide all Documents that support, are utilized and/or relied upon in your answer.
b. Please confirm whether PPL's referenced calculation produces an AC capacity factor of approximately 29.8% and whether this capacity factor is the solar system capacity factor typically expected in PPL's service territory. Provide all Documents that support, are utilized and/or relied upon in your answer.
c. Please provide the percentage of "no-load" solar facilities that have applied for interconnection that are fixed-tilt configurations, and the percentage that are single-axis tracking configurations. Provide all Documents that support, are utilized and/or relied upon in your answer.

PPL Electric Response

a. The annual hours of sunlight are based on data from National Oceanic and Atmospheric Administration ("NOAA").
b. This would produce a capacity factor of 29.78%. Using the data from JSA II-14 CONFIDENTIAL Attachment 1, this capacity factor is within the range of legitimate applications.
c. PPL Electric does not track panel configuration.

KML
EXHIBIT-26

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set III Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 19, 2025
Docket No. R-2025-3057164

JSA III-16

Refer to OCA I-1 Attachment 14 Castanaro, which contains the workpaper used to calculate the Company's projected "cost shift" due to "no load" NEM generators.

a. Please provide all workpapers that are linked in this workpaper (e.g., "Generation Supply Charge-1 Reconciliation – Mar 2025_updated.xlsx") in their original format with formulas intact.
b. In this workpaper, it appears the main source of the increase in PTC as a result of NEM excess generation payouts is an increase in the "E Factor Rate" found in the various "PTC" tabs (e.g., Dec. '25 SCI PTC, Jun. '26 SCI PTC, etc.). Please confirm whether this is correct, and if that is not the case, please explain in detail the basis for your answer. Provide all Documents that support, are utilized and/or relied upon in your answer.
c. In the various forecasted "Reconciliation" tabs, the Company appears to be sourcing the values for Energy Revenues Available, Energy Procurement, PJM Expenses, and Administrative Expenses from the "Mar. '24 Reconciliation" tab.
    1. Is it correct that the values for all forecasted years for these revenue and cost values are from the March 2024 reconciliation? If that is not the case, please explain in detail the basis for your answer. Provide all Documents that support, are utilized and/or relied upon in your answer.
    2. Is it correct that the Company assumed that the March 2024 values for these revenue and costs were appropriate to represent revenues and costs going forward? If not please explain any different assumptions made by PPL. Provide all Documents that support, are utilized and/or relied upon in your answer.

3. Please provide all workpapers that were used to develop the hardcoded values in tab “Mar. ’24 Reconciliation” in their original format with formulas intact. If these workpapers contain any hardcoded values, please include the source files for those as well in their original format with formulas intact.

d. If it is correct that PPL assumes the increase in “no load” NEM generation will reduce the amount of power that the Company must purchase through the default service supply contracts, explain why did the Company not reduce the Energy Procurement and PJM Expenses values in future years to reflect the lower purchases on the DSP contract? Provide all Documents that support, are utilized and/or relied upon in your answer.

e. Please provide an analysis that calculates the reduction in power costs on the default service supply contracts from 2025 through 2030 based on the embedded assumptions of solar generation in this workpaper. Provide all Documents that support, are utilized and/or relied upon in your answer.

PPL Electric Response

a. See JSA III-16 HIGHLY CONFIDENTIAL Attachment 1, and JSA III-16 Attachments 2 and 3.

b. Correct, the E-Factor Rate is the driver of the PTC increase.

c.

1. The Company used the inputs for the Small C&I Price to Compare calculation effective June 1, 2025, for all PTC components other than the E-Factor value provided on line 6 of the PTC calculation in OCA-I-1 HIGHLY CONFIDENTIAL Attachment 14 Castanaro. The Company used the inputs from the GSC-1 Reconciliation for the Period of April 1, 2023, through March 31, 2024, except for the net metering expense value to calculate the E-Factor amount that was included in the PTC calculation. The changing of the net metering expense in the reconciliation changes the E-Factor value, which is then updated within the PTC calculation.
2. The intention of the analysis is to hold all inputs other than the net metering expense in the GSC-1 reconciliation constant in an effort to isolate the impacts of the increase in net metering expense on the PTC. As such, the other inputs are used as a

starting point but do not have an impact on the increase that the Company is intending to demonstrate by modifying the net metering expense only.

3. See JSA III-16 Attachment 3.

d. PPL Electric kept all variables constant with the exception of the net metering expense in the GSC-1 reconciliation constant in an effort to isolate the impacts of the increase in net metering expense on the PTC. Per response to JSA II-9, the Company does not speculate on total costs impacted by potential increases or decreases in demand. The procurements ensure that supply adjusts with demand.

e. See response to JSA II-9.

KML
EXHIBIT-27

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set III Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 19, 2025
Docket No. R-2025-3057164

JSA III-16

Refer to OCA I-1 Attachment 14 Castanaro, which contains the workpaper used to calculate the Company's projected "cost shift" due to "no load" NEM generators.

a. Please provide all workpapers that are linked in this workpaper (e.g., "Generation Supply Charge-1 Reconciliation – Mar 2025_updated.xlsx") in their original format with formulas intact.
b. In this workpaper, it appears the main source of the increase in PTC as a result of NEM excess generation payouts is an increase in the "E Factor Rate" found in the various "PTC" tabs (e.g., Dec. '25 SCI PTC, Jun. '26 SCI PTC, etc.). Please confirm whether this is correct, and if that is not the case, please explain in detail the basis for your answer. Provide all Documents that support, are utilized and/or relied upon in your answer.
c. In the various forecasted "Reconciliation" tabs, the Company appears to be sourcing the values for Energy Revenues Available, Energy Procurement, PJM Expenses, and Administrative Expenses from the "Mar. '24 Reconciliation" tab.
    1. Is it correct that the values for all forecasted years for these revenue and cost values are from the March 2024 reconciliation? If that is not the case, please explain in detail the basis for your answer. Provide all Documents that support, are utilized and/or relied upon in your answer.
    2. Is it correct that the Company assumed that the March 2024 values for these revenue and costs were appropriate to represent revenues and costs going forward? If not please explain any different assumptions made by PPL. Provide all Documents that support, are utilized and/or relied upon in your answer.

3. Please provide all workpapers that were used to develop the hardcoded values in tab “Mar. ’24 Reconciliation” in their original format with formulas intact. If these workpapers contain any hardcoded values, please include the source files for those as well in their original format with formulas intact.

d. If it is correct that PPL assumes the increase in “no load” NEM generation will reduce the amount of power that the Company must purchase through the default service supply contracts, explain why did the Company not reduce the Energy Procurement and PJM Expenses values in future years to reflect the lower purchases on the DSP contract? Provide all Documents that support, are utilized and/or relied upon in your answer.

e. Please provide an analysis that calculates the reduction in power costs on the default service supply contracts from 2025 through 2030 based on the embedded assumptions of solar generation in this workpaper. Provide all Documents that support, are utilized and/or relied upon in your answer.

PPL Electric Response

a. See JSA III-16 HIGHLY CONFIDENTIAL Attachment 1, and JSA III-16 Attachments 2 and 3.

b. Correct, the E-Factor Rate is the driver of the PTC increase.

c.

1. The Company used the inputs for the Small C&I Price to Compare calculation effective June 1, 2025, for all PTC components other than the E-Factor value provided on line 6 of the PTC calculation in OCA-I-1 HIGHLY CONFIDENTIAL Attachment 14 Castanaro. The Company used the inputs from the GSC-1 Reconciliation for the Period of April 1, 2023, through March 31, 2024, except for the net metering expense value to calculate the E-Factor amount that was included in the PTC calculation. The changing of the net metering expense in the reconciliation changes the E-Factor value, which is then updated within the PTC calculation.
2. The intention of the analysis is to hold all inputs other than the net metering expense in the GSC-1 reconciliation constant in an effort to isolate the impacts of the increase in net metering expense on the PTC. As such, the other inputs are used as a

starting point but do not have an impact on the increase that the Company is intending to demonstrate by modifying the net metering expense only.

3. See JSA III-16 Attachment 3.

d. PPL Electric kept all variables constant with the exception of the net metering expense in the GSC-1 reconciliation constant in an effort to isolate the impacts of the increase in net metering expense on the PTC. Per response to JSA II-9, the Company does not speculate on total costs impacted by potential increases or decreases in demand. The procurements ensure that supply adjusts with demand.

e. See response to JSA II-9.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket No. R-2025-3057164
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	
	:	

Solar Energy Industries Association and the Coalition for Community Solar Access, the "Joint Solar Advocates"

JSA Statement No. 1-R

Rebuttal Testimony of
Kevin M. Lucas

Topics Addressed: Responses to the OCA, OSBA CAUSE-PA DIRECT TESTIMONY

Date: January 23, 2026

Table of Contents

I. Introduction 1

Rebuttal of OCA Witness Teti *2*
Rebuttal of OSBA Witness Ewen *5*
Rebuttal of CAUSE-PA Witness Cicero *7*

I. INTRODUCTION

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

A1. My name is Kevin Lucas. I am the Vice President of Policy Analysis at the Solar Energy Industries Association ("SEIA")[1]. My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. ARE YOU THE SAME KEVIN LUCAS WHO FILED DIRECT TESTIMONY IN THIS CASE?

A2. Yes.[2]

Q3. ON WHOSE BEHALF ARE YOU FILING REBUTTAL TESTIMONY?

A3. I am filing testimony on behalf of SEIA and the Coalition for Community Access ("CCSA"), jointly called the Joint Solar Advocates ("JSA") in this proceeding.

Q4. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A4. In this rebuttal testimony, I respond to the direct testimony of Zachary F. Teti on behalf of the Office of Consumer Advocate ("OCA"),[3] the direct testimony of Mark Ewen on behalf of the Office of Small Business Advocate ("OSBA"),[4] and the direct testimony of Patrick M. Cicero on behalf of The Coalition for Affordable Utilities Services and Energy Efficiency in Pennsylvania ("CAUSE-PA").[5] Specifically, I respond to these witnesses' support for the Maximum Registered Peak Load ("MRPL") proposal by PPL Electric Utilities Corporation ("PPL" or "the Company").

Q5. IS THERE A COMMON THEME AMONG THE TESTIMONY OF THESE WITNESSES ON THIS MATTER?

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[1] Capitalized terms not otherwise defined in this Rebuttal Testimony shall be as defined in my Direct Testimony, described more fully below in footnote 2.
[2] Direct Testimony of Kevin M. Lucas on Behalf of Solar Energy Industries Association and the Coalition for Community Solar Access, the "Joint Solar Advocates", JSA Statement No. 1, December 22, 2025. ("Lucas Direct")
[3] Testimony of Zach Teti on Behalf of The Pennsylvania Office Of Consumer Advocate, OCA Statement 6, December 22, 2025. ("Teti Direct")
[4] Direct Testimony and Exhibit of Mark Ewen on behalf of the Office of Small Business Advocate, OSBA Statement No. 1, December 22, 2025. ("Ewen Direct")
[5] Direct Testimony of Patrick M. Cicero on Behalf of The Coalition For Affordable Utility Services And Energy Efficiency In Pennsylvania (CAUSE-PA), CAUSE-PA Statement No. 1, December 22, 2025. ("Cicero Direct")

A5. Yes. As demonstrated by their responses to discovery, these witnesses generally did not perform any independent analyses of the Company's MRPL proposal. Essentially, the witnesses for OCA, OSBA, and CAUSE-PA each took PPL at its word that the MRPL proposal is needed to address cost shifts between customer rate classes due to payments made for excess generation produced by customer-generators exercising their rights under the AEPS Act and is justified because customer-generators do not pay for the "stress" their systems place on PPL's distribution system. Because these witnesses did no independent analysis of the facts represented by PPL, they merely presented unsupported judgments on the claimed benefits of the MRPL proposal and did not recognize adverse impacts on the customer-generator industry.

Q6. DID YOU ADDRESS THESE SPECIFIC ISSUES IN YOUR DIRECT TESTIMONY?

A6. Yes. I performed a detailed analysis of the Company's MRPL proposal and found that it lacked both justification and analytical support.[6] None of the three witnesses that I rebut here performed any analyses – much less the detailed analyses that are required to fully investigate the Company's proposal – to support their direct testimonies.

Rebuttal of OCA Witness Teti

Q7. WHAT IS YOUR RESPONSE TO MR. TETI'S "ANALYSIS" OF THE MRPL PROPOSAL?

A7. Mr. Teti appears to give PPL the benefit of the doubt that its MRPL proposal will improve "the efficiency" of the default service procurement process, but also appears to be perplexed by the Company's contradictory discovery responses related to how customer-generators impact the costs and methodology of procuring default service.[7] Mr. Teti's ultimate recommendation to approve the MRPL is hedged, with several notes that PPL had not offered clear responses to discovery or had offered responses that surprised him.

- When told by the Company that the MRPL proposal would not impact the Default Service Plan ("DSP") procurement efficiency, Mr. Teti noted "Admittedly, I expect

[6] See e.g., Lucas Direct at 20-49.
[7] Teti Direct at 3-4.

there would be an improvement to energy procurement with this change; this is something that I believe PPL should further explore in this proceeding."[8]

- Regarding the "value proposition" between the benefits of load reductions and its effect on PJM costs and how to compensate customer-generators for this reduction, Mr. Teti opined "In this regulatory proceeding, I recommend that PPL demonstrate further clarity on this value proposition."[9]
- After asking several rounds of discovery to the Company about the interaction of customer-generators and the DSP procurement process, clarity was still not forthcoming: "After reviewing these responses, I might have more questions to better understand this process."[10]
- When addressing the core issue of the MRPL – the reclassification of customers from GSC-1 to GSC-2, Mr. Teti wrote "It is my expectation that the supply charge designation would not impact the level at which PJM costs are assigned to PPL. But after reviewing PPL responses to OCA Interrogatory Set XXVII, I would like to better understand the process by which capacity costs and compensation to customer-generators are recovered by PPL customers."[11]

Q8. ARE THERE OTHER INSTANCES WHERE MR. TETI ASSUMES THE COMPANY'S STATEMENTS ARE ACCURATE WITHOUT INDEPENDENTLY VERIFYING THE ANALYSES OR ASSUMPTIONS THAT INFORMED THOSE STATEMENTS?

A8. Yes. While he testified that "This current practice fails to reflect the stress that behind-the-meter generation puts on PPL Electric's distribution system,"[12] Mr. Teti later admitted that he "did not conduct, or review studies, analyses, reports, or data related to PPL's distribution system when reiterating the remarks of Mr. Castanaro."[13]

Similarly, while he testified that "Additionally, the current classification results in non-net metering Small C&I default service customers disproportionately subsidizing the annual cash-outs of customer generators that are, effectively, merchant generators,"[14] Mr. Teti was simply "restating this remark made by PPL witness Castanaro" but "did not

[8] Id. at 3.
[9] Proposing that PPL demonstrate the claimed value proposition later in the case is an improper suggestion that the Company "try again" and submit testimony it should have presented in its direct case.
[10] Teti Direct at 3, fn. 3.
[11] Id. at 12-13.
[12] Id. at 8.
[13] Exhibit KML-28, OCA Response to JSA I-2.
[14] Teti Direct at 8-9.

conduct, or review studies, analyses, reports, or data when restating the remarks of Mr. Castanaro."[15]

Mr. Teti also accepted the Company's erroneous claim that "'the annual cash-outs for the Small C&I customer class will be approximately $60 million to over $300 million by 2029' in the status quo[]" with no investigation.[16] In discovery, Mr. Teti noted "As I stated in Footnote 13 of my Direct Testimony, JSA Interrogatory Set I-26 was helpful in better understanding this analysis, but I did not prepare an analysis or review additional documents to independently confirm Mr. Castanaro's estimate."[17] Notably, the responses in JSA Interrogatory Set I-26, among others, informed the detailed analysis I performed in my direct testimony that found substantial methodological errors and poor assumptions in the Company's cost-shift analysis.[18]

Q9. MR. TETI OPINES THAT THE MRPL WILL INCREASE THE "EFFICIENCY" OF THE DSP PROCUREMENT PROCESS. WHAT IN YOUR VIEW DOES HE MEAN BY THIS AND WHAT DOES HE CITE TO SUPPORT THIS CONCLUSION?

A9. On multiple occasions, Mr. Teti asserts that the MRPL proposal would increase the "efficiency" of the DSP procurement process.[19] By this, he appears to imply that the MRPL proposal will indirectly reduce prices by lowering the risk premium that DSP bidders add to their bids because the bidders will have more certainty on the quantity of energy that they

[15] Exhibit KML-29, OCA Response to JSA I-3.
[16] Teti Direct at 9.
[17] Exhibit KML-30, OCA Response to JSA I-4.
[18] See e.g., Lucas Direct at 37-49.
[19] See e.g., Teti Direct at 3 ("Admittedly, I expect there would be an improvement to energy procurement with this change[.]"), 4 ("The proposed MRPL methodology should accomplish fairness by improving the procurement process for default service and simultaneously compensating customer-generators at a retail value that does not corrupt the efficiency of the procurement process."), 8 ("The proposed delineation of service rate by MRPL is created to procure an efficient quantity of supply for the bulk of customers via DSP suppliers in GSC-1."), 10 ("Yes, however, I would rather think of this as inefficiency that will be improved… Because these customer-generators are virtually commercial customers, the GSC-2 pricing scheme seems more appropriate and would improve procurement efficiency for the procurement of GSC-1, particularly Small C&I GSC-1."), and 12 ("That is, getting the quantity correct is key for the efficient procurement of default service supply that will be passed through to customers at GSC-1.")

need to procure.[20] Not even PPL cited lower bid premiums as a basis for justifying its MRPL proposal.

Q10. HAS MR. TETI PERFORMED ANY ANALYSES RELATED TO THESE CLAIMS?

A10. No, he has not. In fact, "The OCA is not permitted to see bid details following the completion of default service procurement auctions or the constituent components of each individual bidder's bid to provide default supply in the auction and, as a result, the actual quantification of costs and benefits is not possible."[21] In other words, because the OCA is prohibited from seeing these details, Mr. Teti's speculation on the matter cannot be supported.

Q11. GIVEN THIS DEGREE OF UNCERTAINTY ON THE FACTUAL BASIS OF THE COMPANY'S PROPOSAL, DO YOU BELIEVE MR. TETI'S RECOMMENDATION TO APPROVE THE MRPL PROPOSAL IS SUFFICIENTLY SUPPORTED?

A11. No, I do not. Mr. Teti is unable to gather the information he needs to support his claim due to OCA's inability to review DSP auction details, and he has also been understandably confused by some of the Company's discovery responses on the matter. Further, he has not independently scrutinized the Company's purported claims related to cost shifts and grid stress in the context of net metering customer-generators. In aggregate and given these uncertainties, I do not believe Mr. Teti's recommendation that the Commission approve the MRPL proposal is supported, nor should it be considered or accepted.

Rebuttal of OSBA Witness Ewen

Q12. WHAT IS MR. EWEN'S BASIS FOR SUPPORTING THE COMPANY'S MRPL PROPOSAL?

A12. Mr. Ewen's basis for supporting the MRPL proposal is very limited given he only dedicates one page of his direct testimony to this matter, most of which is a recounting of the mechanics of the Company's MRPL proposal. He reiterates, without any independent

[20] Teti Direct at 12.
[21] Exhibit KML-31, OCA Response to JSA I-11.

analysis, PPL's claim that the current process results in a cost shift that should be mitigated.[22] In discovery, Mr. Ewen indicated that he reviewed several discovery responses, including two that were used in my direct testimony to critique the Company's proposal, as well as testimony presented in the UGI Utilities case that discussed a similar matter.[23]

Q13. WILL THE COMMISSION MAKE ITS DECISION IN THIS CASE BASED ON THE INFORMATION PROVIDED IN THE UGI UTILITIES DOCKET?

A13. No. It will make its decision based on the record established in this proceeding. And in this proceeding, as I have shown in my direct testimony, PPL's "cost shift" analysis is fundamentally flawed and should be provided no weight in the Commission's disposition of the MRPL proposal.

Q14. DID THE COMPANY PROVIDE ANY ADDITIONAL INFORMATION TO OSBA THAT YOU DID NOT CITE IN YOUR DIRECT TESTIMONY ON THE ISSUE OF COST SHIFT?

A14. Yes. The Company provided a workpaper in response to an OSBA discovery question that sought information on how much certain customer-generators would have made for their excess energy under the GSC-1 tariff vs. the GSC-2 tariff.[24] PPL's response indicated that these customer-generators would have received higher payments under the GSC-1 tariff than under the GSC-2 tariff.[25] It appears that Mr. Ewen relied on this response to support his claim of an improper cost shift.

Q15. DO HIGHER PAYMENTS RECEIVED BY GSC-1 CUSTOMER-GENERATORS VERSUS GSC-2 CUSTOMER-GENERATORS ALONE MEAN THAT THERE IS A COST SHIFT UNDER THE CURRENT GSC-1/GSC-2 ASSIGNMENT STRUCTURE?

A15. No, it does not. Establishing whether a cost shift exists requires full consideration and evaluation of both costs and benefits. Mr. Ewen's failure to consider the benefits associated with net metered excess generation, as discussed in JSA Witness Justin Barnes's direct

[22] Ewen Direct at 13-14.
[23] Exhibit KML-32, OSBA Response to JSA I-3.
[24] Exhibit KML-33, PPL response OSBA-I-46.
[25] OBSA I-46 Confidential Attachment 1.

testimony, undermines his ability to claim that a cost-shift is present under the current GSC-1/GSC-2 assignment structure. Moreover, the AEPS Act contemplates that a *retail* value will be paid for power sold to the utility for resale – a *wholesale* transaction. As JSA Witness Justin Barnes thoroughly demonstrated in his Direct Testimony, the point is not that excess electricity from customer-generators is purchased as the lowest cost supply, but that PPL has vastly overstated the costs and vastly understated the benefits of such excess customer generation, resulting in the MRPL proposal being a rationalization for changing and lowering the level of customer generator compensation.

Rebuttal of CAUSE-PA Witness Cicero

Q16. WHAT IS MR. CICERO'S BASIS FOR SUPPORTING THE COMPANY'S MRPL PROPOSAL?

A16. Mr. Cicero's concern is grounded in the opinion that "[m]any affordable multifamily housing providers that provide subsidized housing to low income households take rates at the small commercial class and are directly impacted by paying out excess compensation to merchant generators at rates that are artificially high because of the current classification."[26] He further avers that "the rules that allow net metering customers to offset their own usage by that system" was "not meant as an end around interconnection at the wholesale level."[27]

Q17. DOES MR. CICERO PROVIDE ANY INDEPENDENT ANALYSIS OF THE COMPANY'S MRPL PROPOSAL OR ANY DEEPER INSIGHT INTO THE JUSTIFICATIONS FOR ITS FILING?

A17. No. In the section of his testimony that discusses the MRPL proposal, Mr. Cicero merely reiterates the Company's testimony, taken at face value. Nearly every sentence begins with "PPL says", or "According to PPL", or "PPL states".[28] These recitations include critical – and disputed – assertions, such as the current situation "fails to reflect the stress that behind-the-meter generation puts on PPL's distribution system" and that there exists a sizable and growing cross-subsidization that could "be as high as $300 million by 2029."[29]

[26] Cicero Direct at 115.
[27] Id.
[28] Cicero Direct at 113-114.
[29] Id.

Rather than test and evaluate PPL's claims, Mr. Cicero appears to accept them with no further inquiry. When asked about what studies he performed or analyses he conducted to validate the Company's proposal, he responded that he "has not conducted or prepared any studies, analysis, reports, or data regarding PPL's proposed changes to its definition of 'maximum registered peak load' that is discussed on pages 113-115 of his Direct Testimony."[30] When asked the same question about his support for the proposal, the response was the same.[31]

While it is understandable that Mr. Cicero would not want electric customers that provide affordable multifamily housing to low-income customers to pay more for their electricity service than appropriate, his testimony in apparent support of PPL's MRPL proposal is not supported by any independent work product. Rather, he merely passes on the Company's statements without investigation or analysis and opines that if the result the Company's claims is true, it would be counter to his organization's interests. Had he pursued such an investigation, PPL's overstatement of future costs and understatement of benefits would have been apparent, as demonstrated in the JSA direct testimony.

Q18. DO YOU AGREE WITH MR. CICERO'S SECOND CRITIQUE ABOUT NET METERING RULES NOT BEING DESIGNED TO BE "AN END AROUND INTERCONNECTION AT THE WHOLESALE LEVEL"?

A18. No. Mr. Cicero more fully explained this portion of his testimony in discovery. He opined that NEM regulations "were not established solely to provide for payment of generation in excess of usage, they were meant to provide compensation for both albeit at different dollar amounts, with excess generation complementing payment for the crediting of offsetting usage."[32] That said, he also stated that he "did not take a position, nor does he now take a position, about whether any specific customer-generator or group of customer generators

[30] Exhibit KML-34, CAUSE-PA response to JSA 1-1
[31] Exhibit KML-35, CAUSE-PA response to JSA 1-2.
[32] Exhibit KML-36, CAUSE-PA response to JSA 1-8.

should connect at the retail or wholesale level based on the rules, procedures, or compensation available for doing so."[33]

Q19. NOTWITHSTANDING MR. CICERO'S OPINION THAT NEM RULES RELATED TO COMPENSATING EXCESS GENERATION WERE INTENDED TO "COMPLEMENT" COMPENSATION FOR SELF-CONSUMPTION, ARE YOU AWARE OF ANY PENNSYLVANIA PUBLIC UTILITY COMMISSION REQUIREMENT THAT A NEM SYSTEM HAVE ANY MINIMUM AMOUNT OF ELECTRICITY CONSUMPTION OR INDEPENDENT LOAD?

A19. No. My understanding is a customer-generator must be a customer of the utility and there are no Commission requirements that the customer have any particular amount of independent load above the amount of electricity used by the alternative energy system. So long as the customer-generator has complied with applicable PaPUC regulations relating to interconnection and net metering and has a constructed a customer-generator facility/alternative energy system meeting the size and operational requirements of the AEPS Act, there is no restriction on the amount of electricity production that can be net metered to the local electric utility.

Q20. DOES THIS CONCLUDE YOUR TESTIMONY?

A20. Yes, it does. However, I reserve the right to file such additional testimony as may be necessary or appropriate.

[33] Id.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
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KML
EXHIBIT-28

Pa. P.U.C. v. PPL Electric Utilities Corporation
Docket Nos. R-2025-3057164, *et al*.
OCA Response to Interrogatories of Joint Solar Advocates (JSA)
Set I to OCA

OCA-I-2:

2. Ref: Direct Testimony of Zach Teti, OCA St. 6, page 8, lines 22-24. Identify, describe, explain and provide all studies, analyses, reports, data etc. you have conducted, reviewed and/or prepared to support the assertion that behind-the-meter generation puts stress on PPL Electric's distribution system. In your answer, define the term "stress". Provide all Documents you have used, relied upon and/or consulted that support your answer.

Response Date: January 12, 2026

Responding Witness: Zach Teti

Response:

In my testimony, I reiterated remarks made by PPL witness Castanaro: "A small commercial customer's demand is determined based on their load independent of the nameplate capacity of any behind-the-meter generation. This current practice fails to reflect the stress that the behind-the-meter generation puts on PPL Electric's distribution system." I did not conduct, or review studies, analyses, reports, or data related to PPL's distribution system when reiterating the remarks of Mr. Castanaro.

However, though I am not an engineer and do not opine on the effects of behind-the-meter generation putting stress, as that term is used by Mr. Castanaro, on PPL's distribution system, I did review the report on Central Maine Power's Integrated Grid Plan which was published in December 2025 which discusses the issue. A copy of the report is attached.

KML
EXHIBIT-29

Pa. P.U.C. v. PPL Electric Utilities Corporation
Docket Nos. R-2025-3057164, *et al*.
OCA Response to Interrogatories of Joint Solar Advocates (JSA)
Set I to OCA

OCA-I-3:

3. Ref: Direct Testimony of Zach Teti, OCA St. 6, p. 8, line 24 - p. 9, lines 1-2. Identify, describe, explain and provide all studies, analyses, reports, data, etc. you have conducted, reviewed and/or prepared to support the assertion that "the current classification results in non-net metering Small C&I default service customers disproportionately subsidizing the annual cash-outs of customer generators…". Provide all Documents you have used, relied upon and/or consulted that support your answer.

Response Date: January 12, 2026

Responding Witness: Zach Teti

Response:

In my testimony, I restated this remark made by PPL witness Castanaro to emphasize where the Company briefly addresses the proposal rationale. (PPL St. 15, p. 8). I did not conduct, or review studies, analyses, reports, or data when restating the remarks of Mr. Castanaro. I have been utilizing data from other interrogatories and testimony offered throughout this proceeding as well as the UGI Electric DSP V proceeding, Docket No. P-2024-3049343. These interrogatory responses or testimonies are cited in my testimony and are either available to the parties to this proceeding or are publicly available through the PaPUC's website.

KML
EXHIBIT-30

Pa. P.U.C. v. PPL Electric Utilities Corporation
Docket Nos. R-2025-3057164, *et al*.
OCA Response to Interrogatories of Joint Solar Advocates (JSA)
Set I to OCA

OCA-I-4:

4. Ref: Direct Testimony of Zach Teti, OCA St. 6, p. 9, line 16 – p. 9 line 19. Identify, describe, explain and provide all studies, analyses, reports, data etc. you have conducted, reviewed and/or prepared that independently confirm PPL's estimate that the annual cash-outs for the Small C&I customer class will be over $300 million by 2029 in the status quo. Provide all Documents you have used, relied upon and/or consulted that support your answer.

Response Date: January 12, 2026

Responding Witness: Zach Teti

Response:

In my Direct Testimony, I reiterated remarks made by Mr. Castanaro who "estimates that the annual cash-outs for the Small C&I customer class will be approximately $60 million to over $300 million by 2029." As I stated in Footnote 13 of my Direct Testimony, JSA Interrogatory Set I-26 was helpful in better understanding this analysis, but I did not prepare an analysis or review additional documents to independently confirm Mr. Castanaro's estimate.

KML
EXHIBIT-31

Pa. P.U.C. v. PPL Electric Utilities Corporation
Docket Nos. R-2025-3057164, *et al*.
OCA Response to Interrogatories of Joint Solar Advocates (JSA)
Set I to OCA

OCA-I-11:

11. Ref: Direct Testimony of Zach Teti, OCA St. 6. Identify, describe, explain and provide all studies, analyses, reports, data etc. you have conducted, reviewed and/or prepared that address the totality of the costs and benefits of excess generation provided by customer-generators on PPL's system over the last three years and/or prospectively. Provide all Documents you have used, relied upon and/or consulted that support your answer.

Response Date: January 12, 2026

Responding Witness: Zach Teti

Response:

I did not prepare, review, or analyze studies or reports which detail the totality of the costs and benefits of excess generation provided by customer-generators on PPL's system over the last three years and/or prospectively other than those documents referenced in my testimony. The OCA is not permitted to see bid details following the completion of default service procurement auctions or the constituent components of each individual bidder's bid to provide default supply in the auction and, as a result, the actual quantification of costs and benefits is not possible.

KML
EXHIBIT-32

Office of Small Business Advocate's ("OSBA")
Responses to Solar Energy Industries Association
and the Coalition for Community Solar Access
("Joint Solar Advocates" and "JSA")
Interrogatories and Requests for Production
Propounded on OSBA
Set I

JSA TO OSBA-I-1 Ref. OSBA Statement No. 1 (Direct Testimony of Mark D. Ewen). Identify, describe, explain and provide all studies, analyses, reports, data etc. you have conducted, reviewed and/or prepared in connection with your support of PPL's "…proposal to classify default service customers between the 4 General Service Charge ("GSC") rates GSC-1 and GSC-2 based on "net power flow from or into the Company's distribution or transmission system", determined by a threshold of 100 kW peak demand " as you discuss on page 4, lines 4-8 of your Direct Testimony.

OSBA Response Mr. Ewen does not have specific documents responsive to this request. Mr. Ewen refers to his and IEc's experience supporting OSBA since the 1990s plus additional relevant experience in other jurisdictions.

JSA TO OSBA-I-2 Ref. OSBA Statement No. 1 (Direct Testimony of Mark D. Ewen). Identify, describe and explain the basis for your statement on page 14, lines 2-4 that "[g]enerally, credits for total generation in excess of consumption are constrained, as net metering is conceptually based on the idea of the customer meeting its own requirements." Provide all Documents you have used, relied upon and/or consulted that support your answer.

OSBA Response By definition, the term "net metering" implies allowing the customer generator to "offset" its own generation against its consumption for billing purposes. It does not imply that customer generators should be entitled to generate power far in excess of their own consumption, and get paid for that power regardless of when it is exported as if they were full requirements wholesale suppliers.

JSA TO OSBA-I-3 Ref. OSBA Statement No. 1 (Direct Testimony of Mark D. Ewen). Identify, describe, explain and provide all studies, analyses, reports, data etc. you have conducted, reviewed and/or prepared in connection with your assertion that "PPL Electric's current classification results in Small C&I default service customers disproportionally subsidizing customer-generators that, based on their size and output, should be classified as Large C&I." Provide all Documents you have used, relied upon and/or consulted that support your answer.

OSBA Response Please see PPL's responses to OSBA-PPL-I-46, JSA I-25, and JSA I-26. Also see attached Commission Opinion and Order in the Default Service Plan V ('DSP V') proceeding for UGI Utilities, Inc. – Electric Division ('UGI Electric') at Docket No. P02024-3049343. As noted in direct testimony, Mr. Ewen and OSBA provided testimony in the UGI Electric proceeding and supported UGI Electric's proposal to classify customers based on their supply peak load impact. The Commission's Order in the UGI Electric matter is relevant to this proceeding, as PPL is proposing a similar change to the definition of "maximum registered peak load".

JSA TO OSBA-I-4 Ref. OSBA Statement No. 1 (Direct Testimony of Mark D. Ewen). Identify, describe, explain and provide all studies, analyses, reports, data etc. you have conducted, reviewed and/or prepared that address the totality of the costs and benefits of excess generation provided by customer-generators on PPL's system over the last three years and/or prospectively. Provide all Documents you have used, relied upon and/or consulted that support your answer.

OSBA Response Please see response to JSA-OSBA-I-3.

KML
EXHIBIT-33

WITNESS: Gregory Olsen
Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Office of Small Business Advocate (OSBA)
Dated November 14, 2025
Docket No. R-2025-3057164

OSBA-PPL-I-46 Reference PPL Electric Statement No. 15:

a. Regarding page 3, for each of the past five years, please provide a listing of the new individual "no load" net metering installations cited, with the associated generation capacity and ACOSS rate class for each.

b. For each of the past five years, by ACOSS rate class, please provide the number of new net metered customers and the associated generation capacity.

c. For each of the current "no load" net metering installations with capacity in excess of 100 kW, for each of the past three years, please detail the total GSC costs/credits the customer earned as a GSC-1 customer, and the costs/credits the customer would have earned as a GSC-2 customer. Please include supporting calculations and assumptions in MS Excel electronic format.

d. Please provide the Company's evaluation of the net impact of the existing "no load" net metering customers on Small C&I default service procurement costs, compared to the cost of procuring that load through the normal default service procurement process. Please include supporting calculations and assumptions in MS Excel electronic format.

e. If a net metered generator provides energy to PPL Electric's system during peak periods, please explain whether and how those generators are compensated for avoided generation and transmission capacity costs,

under both the existing and proposed classification methods.

f. Please indicate whether the proposed change will have an impact on the affected net metered customers other than the rate at which they are compensated for exported generation and the rate at which they pay for load. If so, please detail the impacts.

PPL Electric Response

a. See OSBA I-46 CONFIDENTIAL Attachment 1, Tab 1 for a list of new “no load” net metering customers that have applied through November 1, 2025.

b. See JSA I-4 CONFIDENTIAL Attachment 1 for new net metered customer generators.

c. See OSBA I-46 CONFIDENTIAL Attachment 1, Tab 2 for a table of “no-load” net metering cashouts with the GSC-1 and the GSC-2 rates for all available cashout data.

d. See response to JSA II-9 and OCA I-1 HIGHLY CONFIDENTIAL Attachments 14 through 16.

e. See response to Part d.

f. There are no additional impacts on the affected customers’ rates other than the customer class designation for default service.

KML
EXHIBIT-34

CAUSE-PA RESPONSES TO

INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS PROPOUNDED BY SOLAR ENERGY INDUSTRIES ASSOCIATION AND THE COALITION FOR COMMUNITY SOLAR ACCESS

SET I

Docket No. R-2025-3057164

1. Ref: Direct Testimony of Partick Cicero. Identify, describe, explain and provide all studies, analyses, reports, data etc. you have conducted, reviewed and/or prepared in connection with PPL's proposed changes to its definition of "maximum registered peak load" as you discuss on pages 113-115 of your Direct Testimony. Provide all Documents you have used, relied upon and/or consulted that support your answer.

Response:

Mr. Cicero has not conducted or prepared any studies, analysis, reports, or data regarding PPL's proposed changes to its definition of "maximum registered peak load" that is discussed on pages 113-115 of his Direct Testimony.

He has reviewed the information submitted by PPL in this proceeding and the Public Utility Commission's Alternative Energy Portfolio Standards Act of 2004, report on AEPS Compliance for Reporting Year 2023-2024, which is publicly available here: https://www.puc.pa.gov/media/3527/aeps-2024-report-final.pdf.

See CAUSE-PA Response to JSA I-3, below for additional information Mr. Cicero consulted in responding to the interrogatories in JSA Set I.

Response provided by or prepared under the supervision of Patrick Cicero

Date: January 12, 2026

KML
EXHIBIT-35

CAUSE-PA RESPONSE TO

INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS PROPOUNDED BY SOLAR ENERGY INDUSTRIES ASSOCIATION AND THE COALITION FOR COMMUNITY SOLAR ACCESS

SET I

Docket No. R-2025-3057164

2. Ref: Direct Testimony of Partick Cicero. Identify, describe, explain and provide all studies, analyses, reports, data etc. you have conducted, reviewed and/or prepared in connection *with your support* of PPL's proposed changes to its definition of "maximum registered peak load" as you discuss on page 115, lines 5-18 of your Direct Testimony. Provide all Documents you have used, relied upon and/or consulted that support your answer.

Response:

See CAUSE-PA Response to JSA Set I-1.

Response provided by or prepared under the supervision of Patrick Cicero

Date: January 12, 2026

KML
EXHIBIT-36

CAUSE-PA RESPONSE TO

INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS PROPOUNDED BY SOLAR ENERGY INDUSTRIES ASSOCIATION AND THE COALITION FOR COMMUNITY SOLAR ACCESS

SET I

Docket No. R-2025-3057164

8. Ref: Direct Testimony of Partick Cicero. With respect to Question 7 and your answer thereto, identify, describe and explain who is doing an "end around interconnection at the wholesale level" as you discuss on page 115, lines 17-18 of your Direct Testimony. Provide all Documents you have used, relied upon and/or consulted that support your answer.

Response:

See CAUSE-PA response to JSA I-3 and the explanation therein. By way of further response, there is no "who" in Mr. Cicero's statement. Mr. Cicero did not take a position, nor does he now take a position, about whether any specific customer-generator or group of customer generators should connect at the retail or wholesale level based on the rules, procedures, or compensation available for doing so. The reference to "end around" in the clause cited is meant to be read in concert with the rest his position that the current rules envision **both** crediting for offsetting usage during a billing period **and** complementary payment for excess generation for any kilowatt hours not previously credited against the customer-generator's usage in prior billing periods. That is, the rules were not established solely to provide for payment of generation in excess of usage, they were meant to provide compensation for both albeit at different dollar amounts, with excess generation complementing payment for the crediting of offsetting usage.

Response provided by or prepared under the supervision of Patrick Cicero

Date: January 12, 2026

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission Coalition For Affordable Utility Services And Energy Efficiency in Pennsylvania Office of Small Business Advocate Brad and Jennifer Woolley	Docket Nos. R-2025-3057164 C-2025-3057844 C-2025-3057889 C-2025-3057946
v.	
PPL Electric Utilities Corporation	

VERIFICATION

I, Kevin Lucas, hereby declare that I am the Vice President, Policy Analysis of Solar Energy Industries Association; that, as such, I am authorized to make this verification on their behalf; that the facts set forth in the foregoing Rebuttal Testimony are true and correct to the best of my knowledge, information and belief, and that I make this verification subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Date: January 23, 2026

By: Kevin Lucas

Digitally signed by Kevin Lucas
DN: cn=Kevin Lucas, o=SEIA, ou, email=klucas@seia.org, c=US
Date: 2026.01.23 10:03:33 -05'00'

Kevin Lucas, Vice President, Policy Analysis
Solar Energy Industries Association

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket No. R-2025-3057164
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	
	:	

Solar Energy Industries Association and the Coalition for Community Solar Access, the "Joint Solar Advocates"

JSA Statement No. 1-SR

Surrebuttal Testimony of
Kevin M. Lucas

Topics Addressed: Responses to the Rebuttal Testimony of PPL and OCA

Date: February 9, 2026

Table of Contents

Introduction 1

Surrebuttal of PPL Witness Castanaro *2*
Surrebuttal of OCA Witness Teti *15*

INTRODUCTION

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

A1. My name is Kevin Lucas. I am the Vice President of Policy Analysis at the Solar Energy Industries Association ("SEIA")[1]. My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. ARE YOU THE SAME KEVIN LUCAS WHO PREVIOUSLY FILED DIRECT AND REBUTTAL TESTIMONY IN THIS CASE?

A2. Yes.[2]

Q3. ON WHOSE BEHALF ARE YOU FILING REBUTTAL TESTIMONY?

A3. I am filing testimony on behalf of SEIA and the Coalition for Community Access ("CCSA"), jointly called the Joint Solar Advocates ("JSA") in this proceeding.

Q4. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A4. In this surrebuttal testimony, I respond to the Rebuttal Testimony of Andrew Castanaro on behalf of PPL Electric Utilities Corporation[3] ("PPL" or "the Company") and the rebuttal testimony of Zachary F. Teti on behalf of the Office of Consumer Advocate ("OCA"),[4] Specifically, I address their inappropriate support for PPL's Maximum Registered Peak Load ("MRPL") proposal.

[1] Capitalized terms not otherwise defined in this Surrebuttal Testimony shall be as defined in my Direct Testimony or Rebuttal Testimony, described more fully below in footnote 2.
[2] Direct Testimony of Kevin M. Lucas on Behalf of Solar Energy Industries Association and the Coalition for Community Solar Access, the "Joint Solar Advocates", JSA Statement No. 1, December 22, 2025. ("Lucas Direct"). Rebuttal Testimony of Kevin M. Lucas on Behalf of Solar Energy Industries Association and the Coalition for Community Solar Access, the "Joint Solar Advocates", JSA Statement No. 1-R, January 23, 2026. ("Lucas Rebuttal").
[3] Rebuttal Testimony of Andrew Castanaro on Behalf of PPL Electric Utilities Corporation, PPL Statement No. 15-R, January 23, 2026. ("Castanaro Rebuttal")
[4] Testimony of Zach Teti on Behalf of The Pennsylvania Office of Consumer Advocate, OCA Statement No. 6-R, January 23, 2026. ("Teti Rebuttal")

Surrebuttal of PPL Witness Castanaro

Q5. HAS PPL PROPOSED ANY MODIFICATIONS TO ITS MRPL PROPOSAL IN ITS REBUTTAL TESTIMONY?

A5. No. The Company continues to advocate for its MRPL proposal in its rebuttal testimony.[5] Mr. Castanaro again mentions the potential cost shift to the small commercial and industrial customer class ("SCI") associated with the sale of excess generation from customer-generators if PPL's proposal is not implemented: "As I noted in my direct testimony, PPL Electric projects that the annual cash-outs for the Small C&I customer class will increase from approximately $11 million as of March 31, 2025, to between $60 million and $300 million by 2029."[6]

In doing so, the Company continues to rely on its flawed analyses on the magnitude of the potential cost shift that it presented in its testimony and rebutted in my direct testimony.[7] Specifically, I showed that PPL's estimated cash-out value is flawed due to an improper use of an "all else equal" analysis, an error in the project cancellation rate assumptions, and unrealistic assumptions about project generation. Importantly, I also noted that PPL included no benefits from front-of-the-meter Distributed Generation ("FTM DG") facilities in its analysis. By continuing to rely on this flawed analysis, PPL undermines the credibility of its entire MRPL proposal and the claimed urgency for its proposed customer -generator reclassification.

Q6. DID MR. CASTANARO ADDRESS YOUR CRITICISMS OF HIS ANALYSIS?

A6. He did, but not effectively in my view. He first observes that the use of the term FTM DG "necessarily implies that the generation facility is not located behind the meter and, therefore, not being used to offset load at the customer location."[8] He continues:

> In that respect, FTM DG is no different than any other generation facility that interconnects directly with an electric system. That only lends further support to

[5] Castanaro Rebuttal at 45:3-8.
[6] *Id.* at 10:22-11:2.
[7] See e.g., Lucas Direct, Section III.
[8] Castanaro Rebuttal at 30:10-11.

classifying them in accordance with the proposed MRPL. They should not be treated the same as behind-the-meter generation because they are different.[9]

Q7. WHAT IS YOUR RESPONSE TO THIS OBSERVATION?

A7. First, I never suggested that generators that were installed in front of a customer's meter had the same relationship to the customer's load as behind-the-meter distributed generation ("BTM DG") systems. In fact, I explicitly described the physical differences between FTM DG and BTM DG systems and their relationship to load.[10]

Mr. Castanaro's logic fails when he makes a shift to "any other generation facility." The issue in this case is not about generation facilities, but about customer-generators. Customer-generators are customers of the Company who happen to own or operate generation assets, and those customers must take service on one of the various retail rates that is offered. PPL does not offer retail service to BTM DG systems or FTM DG systems; it offers retail service to *customers* who own and operate BTM DG systems and FTM DG systems. This is important because, among other things, PPL improperly commingles the customer and generator components of a "customer-generator."

Further, the physical configuration of these systems is treated identically by the Company through its interconnection process. Both FTM DG and BTM DG systems go through the Company's same interconnection screens, and each will be processed based on the physical characteristics of the facility. If any upgrades are needed to ensure safe connection to the grid, then the customer-generator – regardless of whether they wish to install a FTM DG or BTM DG system – will be responsible for the upgrades.

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[9] *Id.* 30:11-15.

[10] Lucas Direct at 9:12-10:6. "In Pennsylvania, NEM systems come in two broad categories, which I am denoting as BTM DG or FTM DG. BTM DG is typically installed on the customer side of the utility meter at a site that has more than de minimis on-site load. These may be rooftop systems at a residence or business, or a ground mount facility on the campus of a larger commercial building. Energy from a BTM DG system will first flow to serve the customer's on-site load, and any excess beyond that demand will flow through the meter to the Company's grid.

I use the term FTM DG for projects that are typically installed with minimal or *de minimis* on-site load. These are projects that feed the bulk of their power directly into the Company's distribution grid. PPL uses the term "no load customer-generators" for these projects. Both FTM DG and BTM DG systems can operate under the Pennsylvania NEM framework. Both follow the same calculation methodology to determine what energy is consumed on-site and what is exported, with the distinction that BTM DG systems have a relatively even balance between energy consumed on-site and energy exported to the grid, while FTM DG systems export the vast majority of their generation to an EDC."

Finally, whether the Company agrees or not, there are specific statutory obligations related to the compensation of excess exported generation that it must provide to both BTM DG and FTM DG customer-generators. Suggesting that it can treat BTM DG and FTM DG systems differently because one offsets more load at the customer location or produces more excess electricity than the other does, is not, I am advised, consistent with Pennsylvania law.

Q8. WHAT IS MR. CASTANARO'S RESPONSE TO YOUR CRITICISM ABOUT THE "ALL ELSE EQUAL" FLAW IN HIS ANALYSIS?

A8. Mr. Castanaro does not agree that this approach is methodologically flawed. He states:

> The Company's analysis was intended to isolate the direction and magnitude of net metering expenses related to excess generation compensation. Although additional FTM DG could reduce overall supply procurement, other factors such as growing demand or customer switching could increase procurement requirements and offset the impact of FTM DG excess generation. For this reason, the Company kept the other variables constant in its analysis. This approach ensures clarity in evaluating the incremental cost impact and counters the assertion that the analysis results in purchasing two units of energy to serve one unit of load.[11]

Q9. DO YOU AGREE WITH THIS EXPLANATION?

A9. No, I do not. First, as a matter of physics, generation from FTM DG systems reduces the amount of power that must be supplied by the PJM bulk power grid to meet PPL customers' load. If PPL customers consume 20,000 MWh in an hour, and 500 MWh is supplied from FTM DG systems connected to the PPL distribution grid, then physics dictates that only 19,500 MWh will be supplied by the bulk power grid.[12] There is no "could" in this scenario; the grid simply does not provide more power to customers than is being consumed at their properties.

Additionally, the suggestion that "other factors", such as growing demand or customers switching, somehow becomes relevant to an "all else equal" analysis is a direct contradiction to the "all else equal" nature of the analysis. In reality, many factors, such as weather,

[11] Castanaro Rebuttal at 31:18-32:3.

[12] This simple example ignores losses. In reality, because FTM DG systems are closer to customer load, their generation avoids transmission and distribution losses and results in a greater than 1:1 offset of wholesale market purchases.

customer growth, and customer switching will impact PPL's final default service procurement requirements. PPL did not contemplate any change to customer consumption in its analysis but instead held both sales and procurement constant. In doing so, it explicitly rejected the influence of these and other factors in its analysis, which is perfectly appropriate. PPL's flaw is not that it ignored these factors, but that it instead included one factor – an increase in FTM DG generation – and ignored the physical consequence of this choice. The original analysis (which continues to be relied upon in the Company's rebuttal) assumed a substantial increase in FTM DG generation *without a corresponding decrease in procurement and subsequent procurement costs*. This is a critical analytical error.

The same error would have been repeated if the Company assumed that hotter weather would have increased energy sales but also decided that this would not result in higher procurement needs. Likewise, if it had assumed that many customers would switch from default service to competitive suppliers but simultaneously assumed that default service procurement would not decrease, it would have made the same logical mistake. There is no way around the fact that the Company's "all else equal" analysis is flawed. Default service suppliers ("DSP suppliers") do not purchase two units of energy to serve one unit of load. The Company's failure to account for this in its analysis is not an "approach [that] ensures clarity" as claimed by Mr. Castanero but a clear methodological error.

Q10. WHAT WOULD BE REQUIRED FOR THE AMOUNT OF ENERGY PURCHASED FROM DSP SUPPLIERS TO NOT CHANGE AS MORE FTM DG WAS ADDED TO THE COMPANY'S SYSTEM?

A10. This would require either that DSP suppliers claim sales that were higher than what they provided to PPL's customers, or for PPL to pay DSP suppliers for power they did not supply. To use the simple example above, the first instance would require DSP suppliers to claim they in fact did provide 20,000 MWh to the Company's customers in that hour despite 500 MWh coming from FTM DG systems on the distribution grid. The second instance would require PPL to pay the DSP supplier for 20,000 MWh despite the suppliers only claiming 19,500 MWh in procurement services. Either of these hypothetical instances is highly

problematic: suppliers misrepresenting their sales, or the Company paying for – and recovering costs from its customers – services that it did not receive.

Q11. WHAT IS MR. CASTANARO'S REBUTTAL ON THE CANCELLATION RATE ERROR ASSUMED TO BE APPLICABLE TO CUSTOMER-GENERATOR PROJECTS?

A11. Mr. Castanaro claims that the "36% cancellation rate is the actual cancellation rate and is used as the base case, which essentially captures the cancelled projects and therefore acts as 0% incremental cancellations."[13]

Q12. IS THIS CORRECT?

A12. No. While Mr. Castanaro's rebuttal testimony attempts to shift the goalposts by now claiming that the 36% cancellation rate "essentially" acts as 0% incremental cancellation, the numbers in his workpapers do not match this assertion.

Below are three screenshots from three workpapers that support PPL Exhibits AC-1, AC-2, and AC-3.[14] Per Mr. Castanaro's testimony, "PPL Electric Exhibits AC-1, AC-2, and AC-3 show projections based on cancellation rates for interconnection projects of 36%, 50%, and 75%, respectively."[15] In each of these screenshots, there are two lines for each year. The first includes the total projected kWh bank of excess exported energy if all FTM DG projects that have applied for interconnection were built, while the second makes an adjustment to allow for project cancellations. Note that each adjusted row includes the phrase "w/ Cancellation Rate of ~36%" in the label; however, these cells were mislabeled in the original workpapers and should have been updated with the actual cancellation rates (supposedly 36%, 50%, and 75%).

[13] Castanaro Rebuttal at 33:21-34:1.
[14] KML Exhibit-22 (JSA VI-2 Attachment 1 – OCA I-1 Attachment 14 Castanaro). The screenshots are from the "Cashout Values" tab of the workpapers of "JSA VI-2 Attachment 1 - OCA I-1 Attachment 14 Castanaro" (supporting Exhibit AC-1), "JSA VI-2 Attachment 2 - OCA I-1 Attachment 15 Castanaro" (supporting Exhibit AC-2), and "JSA VI-2 Attachment 3 - OCA I-1 Attachment 14 Castanaro" (supporting Exhibit AC-3).
[15] Castanaro Direct at 7, fn. 1.

	Total	SCI Only(1)
Projected 2025 kWh Bank	49,842,515	17,444,880
Projected 2025 kWh Bank w/ Cancellation Rate ~36%	49,842,515	17,444,880
Projected 2026 kWh Bank	172,008,146	60,202,851
Projected 2026 kWh Bank w/ Cancellation Rate ~36%	172,008,146	60,202,851
Projected 2027 kWh Bank	1,119,886,777	391,960,372
Projected 2027 kWh Bank w/ Cancellation Rate ~36%	1,119,886,777	391,960,372
Projected 2028 kWh Bank	2,663,225,657	932,128,980
Projected 2028 kWh Bank w/ Cancellation Rate ~36%	2,663,225,657	932,128,980
Projected 2029 kWh Bank	4,087,014,528	1,430,455,085
Projected 2029 kWh Bank w/ Cancellation Rate ~36%	4,087,014,528	1,430,455,085
Cancellation Rate		*cancellation rate now incorporated into kWH projection*
Percentage of SCI Load in Queue	35%	

Figure 1 - Exhibit AC-1 ("36%" cancellation rate)

	Total	SCI Only(1)
Projected 2025 kWh Bank	49,842,515	17,444,880
Projected 2025 kWh Bank w/ Cancellation Rate ~36%	24,921,257	8,722,440
Projected 2026 kWh Bank	172,008,146	60,202,851
Projected 2026 kWh Bank w/ Cancellation Rate ~36%	86,004,073	30,101,426
Projected 2027 kWh Bank	1,119,886,777	391,960,372
Projected 2027 kWh Bank w/ Cancellation Rate ~36%	559,943,388	195,980,186
Projected 2028 kWh Bank	2,663,225,657	932,128,980
Projected 2028 kWh Bank w/ Cancellation Rate ~36%	1,331,612,828	466,064,490
Projected 2029 kWh Bank	4,087,014,528	1,430,455,085
Projected 2029 kWh Bank w/ Cancellation Rate ~36%	2,043,507,264	715,227,542
Cancellation Rate		*cancellation rate now incorporated into kWH projection*
Percentage of SCI Load in Queue	35%	

Figure 2 - Exhibit AC-2 (50% cancellation rate)

	Total	SCI Only(1)
Projected 2025 kWh Bank	49,842,515	17,444,880
Projected 2025 kWh Bank w/ Cancellation Rate ~36%	12,460,629	4,361,220
Projected 2026 kWh Bank	172,008,146	60,202,851
Projected 2026 kWh Bank w/ Cancellation Rate ~36%	43,002,037	15,050,713
Projected 2027 kWh Bank	1,119,886,777	391,960,372
Projected 2027 kWh Bank w/ Cancellation Rate ~36%	279,971,694	97,990,093
Projected 2028 kWh Bank	2,663,225,657	932,128,980
Projected 2028 kWh Bank w/ Cancellation Rate ~36%	665,806,414	233,032,245
Projected 2029 kWh Bank	4,087,014,528	1,430,455,085
Projected 2029 kWh Bank w/ Cancellation Rate ~36%	1,021,753,632	357,613,771
Cancellation Rate		*cancellation rate now incorporated into kWH projection*
Percentage of SCI Load in Queue	35%	

Figure 3 - Exhibit AC-3 (75% cancellation rate)

The error in Mr. Castanaro's Exhibit AC-1 workpaper is immediately visible when comparing it to the other two workpapers. The values in the various "Projected 20XX kWh Bank" rows are identical across all three workpapers and exactly match the values that I included in my direct testimony.[16] The values in the "Projected 20XX kWh Bank w/ Cancellation Rate of ~36%" (which again, are mislabeled in the workpapers associated with Exhibits AC-2 and AC-3) reflect a discount from the maximum kWh bank in each year and should correspond to adjustments of 36% in Exhibit AC-1, 50% in Exhibit AC-2, and 75% in Exhibit AC-3.

The values in Exhibit AC-2 and Exhibit AC-3 exactly match the 50% and 75% discount that was claimed. That is, the 2026SCI Only bank used in Exhibit AC-2 of 30,101,426 kWh is exactly 50% (representing a 50% cancellation rate) of the starting 2026 value of 60,202,851, while the 15,050,713 kWh value in Exhibit AC-3 is exactly 25% (representing the 75% cancellation rate) of the same starting value.[17] However, the "Projected 20XX kWh Bank" values in the workpaper supporting Exhibit AC-1, which is supposed to include a 36% cancellation rate, are exactly equal to the "Projected 20XX kWh Bank w/ Cancellation Rate of 36%" and thus reflect no downward adjustment. They are, as pointed out in my direct testimony, reflective of a 0% cancellation rate, not a 36% cancellation rate, and not a 0% "incremental" cancellation rate.

This error results in a substantial overestimate of the maximum potential cost shift that could occur under the Company's three project cancellation scenarios. Fixing the Company's workpapers to properly reflect the 36% cancellation rate would reduce the top-line estimate of roughly $300 million referenced in Mr. Castanaro's testimony to roughly $167 million.[18] Of course, this updated figure continues to be flawed due to the other errors in the

[16] Lucas Direct at 39-40, Table 1.
[17] Worksheet values are rounded to the nearest 1 kWh, but the underlying values are in fact exactly 50% and 75% in these workpapers.
[18] KML Exhibit-22 (JSA VI-2 Attachment 1 – OCA I-1 Attachment 14 Castanaro).

Company's analysis, but correcting this error substantially undercuts the worst-case outcome that the Company claims it must avoid.

Q13. DID YOU FIND OTHER PROBLEMS WITH THE COMPANY'S ANALYSIS WHILE TRACKING DOWN THIS ISSUE?

A13. Yes. I considered whether Mr. Castanaro alternatively erred when he indicated the analyses in Exhibit AC-2 and Exhibit AC-3 represent a 50% and 75% project cancellation rate, respectively, and instead could have represented a 50% and 75% "incremental" cancellation rate as he asserts in his rebuttal testimony. However, the math again does not support these cancellation rates.

If one assumes Exhibit AC-2 represents a 50% incremental cancellation rate over the baseline rate of 36%, this would imply a 54% overall cancellation rate.[19] Similarly, the "incremental" Exhibit AC-3 cancellation rate of 75% would translate into an overall cancellation rate of 63%.[20] One could then use these updated cancellation rates to project what the generation would have been if no projects were cancelled. Because the analysis supposedly starts with the same set of projects, this figure should be consistent across the three exhibits. But applying an updated cancellation rate of 54% and 63% to Exhibits AC-2 and AC-3 does not result in the same total potential generation from the group of projects. The values in Figures 1-3 above clearly do not support these alternative "incremental" cancellation rates.

I also analyzed the original project list that the Company provided when asked to produce all projects included in the Exhibit AC-1, AC-2, and AC-3 workpapers. The Company responded with a list of roughly 750 projects that it referred to as "merchant generators", which it noted "In the net metering context, PPL Electric refers to customer-generators that have no independent load as merchant generators. See PPL Electric St. No. 15, p. 6, lines 20-21."[21] These are the same projects that I analyzed in my direct testimony.[22]

[19] 36% * 150% = 54%.
[20] 36% * 175% = 63%.
[21] JSA II-14 CONFIDENTIAL. (Not an exhibit or an attachment to this testimony.)
[22] See e.g., Lucas Direct at 40:7-44:9.

I went back to this workpaper and tried to reconcile the expected generation from these projects on a year-by-year basis with the generation values found in Exhibits AC-1 through AC-3. This investigation introduced even more uncertainty around the Company's numbers. I was not able to reconcile the estimated kWh bank in any year to the original source of projects that supposedly created the bank. I tried using both calendar years and energy years, a 0% cancellation rate and a 36% cancellation rate, and other adjustments to get the data to fit, but nothing worked. I requested additional discovery from the Company to reconcile their own workpapers but have not yet received a response.

Q14. WHAT IS YOUR CONCLUSION WITH RESPECT TO PPL'S CLAIMED CANCELLATION RATE FOR CUSTOMER-GENERATOR PROJECTS?

A14. Not only do I believe that the Company's cancellation rate analysis is wrong, the additional analysis responding to PPL's rebuttal testimony has also uncovered even more uncertainty related to the Company's cost shift analysis. It cannot be simultaneously true that PPL's original analysis included a 36% cancellation rate and that it also provided data for 50% and 75% cancellation rates. It also cannot be true that the 50% and 75% cancellation rate values correspond to an "incremental" cancellation rate. Now, the very underpinning of the Company's analysis – the generation from a specific set of FTM DG projects forecast to come online in specific years – cannot be reconciled between the Company's own workpapers.

Q15. WHAT IS MR. CASTANARO'S REBUTTAL TESTIMONY ON THE COMPANY'S UNREALISTIC ASSUMPTIONS ABOUT THE AMOUNT OF GENERATION FROM CUSTOMER-GENERATORS?

A15. Mr. Castanaro reiterates his claim that the Company "used appropriate estimates for the amount of generation anticipated."[23] He continues by stating that "even if it overestimated the amount of generation from no load customer-generators, it would only lessen the magnitude of the cross-subsidization, not negate the fact that it is occurring."[24]

[23] Castanaro Rebuttal at 34:2-3.
[24] *Id.* at 34:3-5.

Q16. WHAT IS YOUR RESPONSE TO MR. CASTANARO'S ASSERTION THAT THE AMOUNT OF CUSTOMER-GENERATION GENERATION IS IRRELEVANT AND HIS CONTINUED CLAIM THAT PPL USED APPROPRIATE ESTIMATES OF GENERATION FROM CUSTOMER-GENERATORS?

A16. His claim is wrong. An entire branch of mathematics – statistics – is dedicated to determining the reasonableness and appropriateness of estimates such as the one advanced by the Company. I used Excel to produce basic statistical information about the set of 391 projects for which developers provided generation estimates to PPL. Given these are the same parties that are designing and building the projects, they should represent a reasonable approximation of generation ranges in PPL's territory. This sample had an average generation per kW of capacity of 1,829 kWh/kW, with a standard deviation of 216 kWh/kW.[25]

The Company's estimate for generation was 2,609 kWh/kW. Based on the set of nearly 400 projects where developers provided production estimates, the Company's value is 3.6 standard deviations away. Assuming a normal distribution, the chances of any single project that shares the same characteristics of the sample set (that is, a solar project in PPL's territory) having a production of 2,609 kWh/kW or more is 0.0152%, or roughly one out of 6,600.[26] In other words, finding even one project with this level of generation would be an extreme outlier. However, the Company did not assume one project would reach this level of output, it assumes that roughly 350 projects would reach this level of output.

Q17. IS THAT ASSUMPTION "APPROPRIATE"? AS CLAIMED BY THE COMPANY

A17. No. Assuming the developers who provided production estimates for their projects to PPL collectively submitted reasonable estimates of production in PPL's territory, it is mathematically impossible that 350 other projects would all reach the production levels

[25] The standard deviation is a measure of how "wide" the distribution of results is. Assuming a normal distribution, 68% of values can be expected to be within one standard deviation (plus or minus) of the mean.

[26] The z-score of the Company's point estimate given the set of projects with developer-provided forecast estimates is 3.613. Assuming a normal distribution, the probability of a z-score being larger than 3.613 is roughly 0.0001515.

assumed by the Company.[27] The Company's FTM DG production generation assumptions are unavoidably, uncontrovertibly, and undeniably invalid.

Q18. GIVEN THIS IS THE CASE, DO YOU AGREE WITH THE COMPANY THAT IT WOULD "ONLY LESSEN THE MAGNITUDE OF THE CROSS-SUBSIDIZATION, NOT NEGATE THE FACT THAT IT IS OCCURRING"?

A18. In part, but that statement does not fully reflect the entire situation. I agree that using the Company's methodology, a reduction in assumed production from FTM DG systems will result in lower cost shifts shown in their workpapers. That said, this does not correct the other errors with the Company's analysis. More importantly, however, the Company appears to assert that *any* degree of cost shift – regardless of size – is untenable and must be avoided.

Q19. DO YOU AGREE THAT ALL COST SHIFTS OF ANY DEGREE ARE UNREASONABLE OR INAPPROPRIATE?

A19. With the caveat that I am not an attorney and not offering a legal opinion, no, it is not. My understanding is that utility rates must not be unreasonably or *unduly* discriminatory. For example, cost shifts exist between the Company's various customer classes, as not every customer class earns the Company the exact same rate of return on its assets used and useful in providing service. Likewise, there are intraclass cost shifts inherent in average rates; rural customers are subsidized by urban customers, single-family households are subsidized by multifamily unit households, and so on. These rates have all been deemed reasonable because they are not unduly discriminatory towards any individual or customer class. Typically, rates do not perfectly match the utility's cost of service study, including PPL's. More importantly, by passing the AEPS Act, which was intended to encourage the development of alternative energy systems, like wind and solar, among others, establish customer-generators and net metering, and require customer-generators engaging in net

[27] Assuming generation of these projects were randomly distributed and independent of each other based on the sample set, the odds of 354 new projects attaining production levels of at least 2,609 kW/kWh is $7.35 \times 10^{-1,353}$. This is roughly equal to one chance in $1.4 \times 10^{1,352}$, or one followed by 1,352 zeros. By comparison, there are about 10^{82}, or one followed by 82 zeros, atoms in the universe. https://www.livescience.com/how-many-atoms-in-universe.html

metering to be compensated at full retail value, it is not unreasonable to conclude that, as a matter of public policy, the Pennsylvania General Assembly understood that some level of cost shifting and customer subsidization was an appropriate policy choice for the Commonwealth.

Q20. WHAT IS MR. CASTANARO'S RESPONSE TO YOUR CRITICISM OF THE COMPANY'S FAILURE TO INCLUDE IN ITS MRPL PROPOSAL ANY BENEFITS OF FTM DG SYSTEMS?

A20. Mr. Castanaro again falls back on his "all else equal" claim:

> As I addressed with the third concern, inputs were kept constant to isolate the impact of one variable and that although FTM DG could reduce forecasted peaks, other market factors, such as higher than projected peaks or FTM DG not being available during those peaks, could offset those benefits and were therefore not included.[28]

Q21. WHAT IS YOUR RESPONSE TO THIS CRITIQUE?

A21. Mr. Castanaro is conflating two different issues. Including benefits in the analysis does not require inputs to be unreasonably adjusted, but only to be logically adjusted. Likewise, consideration of benefits can easily include scenarios that test results under various real-world situations.

PPL's assumptions are the equivalent of the following hypothetical. Assume PPL was a vertically integrated utility that owned generation and forecasted a shortfall in 2030 that required the addition of 200 MW of capacity. Further assume the baseline assumption is that it would build a 200 MW power plant, but it also analyzed the potential of meeting the capacity shortfall with a program targeting new distributed energy resources such as solar and storage along with demand-side management resources like energy efficiency and demand response (collectively, the "DER/DSM portfolio"). In this instance, the Company would calculate the cost of implementing the DER/DSM portfolio and would compare it to the cost of building the new power plant. If the former is lower than the latter, then a reasonable response would be to pursue the DER/DSM portfolio and not build the power plant.

[28] Castanaro Rebuttal at 34:12-16.

But under the Company's logic in this case, the analysis above would calculate the DER/DSM portfolio's cost while also assuming the power plant is built (and its costs recovered), and then "observe" that implementing the DER/DSM portfolio would increase costs for ratepayers and be an unreasonable path forward. Of course, no reasonable analysis would result in the construction of redundant resources for the 200 MW capacity shortfall; only one or the other would be selected based on a fulsome review of the costs and benefits of each resource. The Company's analysis in this case fails to reach this basic but inevitable conclusion. This hypothetical is realistic given PPL's current strong interest in being permitted to build its own new generation to meet rising demand for electricity. MRPL is a way for PPL, who hopes to enter the generation business, to reduce amounts paid to what it calls merchant generators such as FTM DGs that would also be supplying load on the PPL grid.[29]

Q22. PLEASE SUMMARIZE YOUR RESPONSE TO PPL WITNESS CASTANARO'S REBUTTAL TESTIMONY.

A22. PPL's "all else equal" defense of its MRPL proposal is unreasonable, inappropriate and self-serving. Holding DSP energy procurement costs constant while reducing the quantity of energy that must be supplied through the DSP suppliers is flatly incorrect. For this assumption to occur, either the Company or suppliers would be paying for or claiming sales of energy that they did not procure or sell.

The Company's generation assumptions used in their cost shift analysis are inaccurate and cannot be relied upon. It would be very unusual for even one facility to attain the generation level claimed to be reasonable by PPL, but a mathematical impossibility for all of the roughly 350 facilities whose generation was estimated by the Company to all attain this level.

These errors in the Company's analysis are material as they directly impact the magnitude of any cost shift among or within customer rate classes that may be present. The fundamental

[29] See, https://investors.pplweb.com/2026-01-20-PPL-Corporation-statement-on-Trump-Shapiro-call-for-new-power-auction-to-spur-construction-of-power-plants-paid-for-by-data-centers.

claimed underpinning for MRPL – the need to avoid a massive cost increase for small commercial customers – is a claimed cost shift the Company has not supported. Utility regulation does not preclude all cost shifts from occurring, only those that are unreasonable. "Unreasonable" is by definition a matter of degree, and the Company's inability to produce a reasonable analysis that fairly calculates any purported cost shift undermines its assertion that the current customer classification methodology results in an unreasonable cost shift, thereby allegedly justifying its MRPL proposal.

Surrebuttal of OCA Witness Teti

Q23. WHAT WAS YOUR PRIMARY REBUTTAL TO OCA WITNESS TETI'S DIRECT TESTIMONY?

A23. My primary rebuttal was that Mr. Teti did not perform any independent analyses but instead accepted PPL's arguments, despite Mr. Teti admitting he is prohibited by regulation from garnering the information needed to confirm or challenge PPL's proposal.[30] Mr. Teti also noted that the Company's application lacked clarity and discovery responses did not always dispel this haze.[31] Mr. Teti also opined on the "efficiency" of the DSP procurement process, although neither Mr. Teti nor the OCA knows whether an increase in "efficiency" would actually reduce DSP supplier prices.[32]

Q24. DOES MR. TETI ELABORATE ON THESE THEMES IN HIS REBUTTAL?

A24. Yes, he does. In fact, Mr. Teti reframes his support of the MRPL proposal away from the potential cost shift and towards one of increasing efficiency of the DSP procurement process: "Altogether, I would rather think of the MRPL proposal as an approach to improving procurement efficiency and a continued allowance of compensation at a retail rate that is aligned with what these customer-generators are offering (rather than the elimination of subsidization)."[33] Mr. Teti also offered a new analysis that he said "illustrate[s] the cash flow arrangements discussed by Mr. Lucas as I understand them[.]"

[30] See e.g., Lucas Rebuttal at 2:17-5:19.
[31] *Id.*
[32] *Id.*
[33] Teti Rebuttal at 5:4-7.

Q25. AFTER READING HIS REBUTTAL TESTIMONY, DO YOU HAVE ANY BETTER UNDERSTANDING OF WHAT MR. TETI MEANS BY "PROCUREMENT EFFICIENCY"?

A25. To some degree. Mr. Teti discussed his belief that DSP suppliers currently price in a premium to their bids to account for differences between the net metering forecast provided by PPL and the actual generation that occurs from those net metering facilities. He provided a schedule that purports to quantify this risk.[34]

Q26. DID YOU ANALYZE THIS NEW SCHEDULE?

A26. Yes.

Q27. DOES MR. TETI'S NEW SCHEDULE SUPPORT HIS CONCLUSION THAT DSP SUPPLIERS ESTABLISH A PREMIUM IN THEIR BIDS TO ACCOUNT FOR GENERATION FORM NET METERING FACILITIES?

A27. No. Mr. Teti's analysis is in two parts, with the second part feeding into the first. In the second part of the analysis, Mr. Teti devises a schedule that appears to calculate a probability-weighted "rate requirement" that DSP suppliers would calculate when developing their bids for PPL's default supply RFP. In his example, duplicated below in Figure 4, four scenarios with different completion rates and capacity factors are assigned probabilities to calculate a final weighted-average rate requirement. The difference between this value (in purple) and the original DSP Supplier Cost (in yellow) is denoted in his workpapers as "the risk premium."[35]

[34] Teti Rebuttal at 12:2-3, referencing OCA St. 6-R, Exhibit ZT-1R.
[35] See, OCA St. 6-R, Exhibit ZT-1R Workpaper at 2.

OCA Exh. ZT-1R
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MAXIMUM REGISTERED PEAK LOAD (MRPL) - NUMERICAL EXAMPLE (CONT'D)

[A]	Gross Load (w/ Losses)	*MWh*	500,000				
[B]	Customer Load (w/out Losses)	*MWh*	425,000				
[C]	Current BTM Generation Nameplate Capacity	*MW*	15				
[D]	Pipeline BTM Generation Nameplate Capacity	*MW*	8				
[E]	DSP Supplier Cost	*$/MWh*	$ 72.50	*assumed marginal cost is flat (not increasing)*			
			[1]	[2]	[3]	[4]	[5]
			Scenario 1 PPL	Scenario 2 Low Shortage Risk	Scenario 3 Med Shortage Risk	Scenario 4 High Shortage Risk	Average
[F]	Scenario Likelihood	%	10%	30%	40%	20%	100%
[G]	Completion Rate	%	50%	30%	30%	15%	29%
[H]	Capacity Factor	%	30%	30%	20%	20%	24%
[I] = [A]	Gross Load (w/ Losses)	*MWh*	500,000	500,000	500,000	500,000	500,000
[J] = (([C] x [H]) + ([D] x [G]x[H])) x 4380	Net Metering	*MWh*	24,966	22,864	15,242	14,191	18,291
[K] = [I] - [J]	Net Energy Demand	*MWh*	475,034	477,136	484,758	485,809	481,709
[L] = [K-1]	**GSC-1 SCI Procured Amount**	*MWh*	475,034	475,034	475,034	475,034	475,034
[M] = [K] - [L]	Shortage	*MWh*	-	2,102	9,724	10,775	6,675
[N] = [E-1] x [L]	DSP Supplier Cost - GSC-1 SCI Procured Amount	$	$ 34,439,965	$ 34,439,965	$ 34,439,965	$ 34,439,965	$ 34,439,965
[O] = [E-1] x [M]	DSP Supplier Cost - Shortage Cost	$	$ -	$ 152,424	$ 704,961	$ 781,173	$ 483,946
[P] = [N] + [O]	**Total Cost**	*$*	$ 34,439,965	$ 34,592,389	$ 35,144,926	$ 35,221,138	$ 34,923,911
[Q] = [P] / [L]	**DSP Supplier Bid - Rate Requirement**	*$/MWh*	$ 72.50	$ 72.82	$ 73.98	$ 74.14	$ 73.52
[R] = [L] x [Q]	GSC-1 SCI Procurement Cost	*$*					$ 34,923,911
[S]	*Check*	*$*					*$ 34,912,500*

Figure 4 - OCA Exhibit ZT-1R Page 2

Q28. WHAT ARE YOUR CONCERNS ABOUT THIS SCHEDULE?

A28. I have several. First, the figures that Mr. Teti uses for gross load (500,000 MWh in Row A), net metering (25,000 MWh in Row J), and customer load (425,000 MWh in Row B) do not appear to correspond to any values relevant to the facts of this case. Mr. Teti does not provide any references or citations for these values, and they do not appear consistent with any values provided by PPL in its application, testimony, or discovery responses. The closest reference I could find in the Company's workpapers suggest annual sales for the Small Commercial and Industrial ("SCI") class of about 1.8 million MWh, a net metering adjustment of 50,000 MWh, and line losses around 2.5%.[36]

Even if one were to assume Mr. Teti's 500,000 MWh of gross load and 25,000 MWh of net metering were reasonable or accurate, there is no explanation for why customer load (425,000 MWh in Row B) is so much lower. This would require either sizable additional

[36] KML Exhibit-22 (JSA VI-2 Attachment 1 – OCA I-1 Attachment 14 Castanaro, tab SCI GSC1).

quantities of net metering or line losses that are inconsistent with the operation of the Company's distribution system. I also cannot understand why when calculating the annual amount of solar generation Mr. Teti multiplies the capacity factor by 4,380, which is exactly 50% of the hours in the year. Generation is properly calculated by multiplying the capacity factor by 8,760.[37]

Putting these issues aside, the real problem with the schedule comes from the dramatically different assumptions for capacity factors in Row H across the scenarios. In the first two scenarios, Mr. Teti assumes a capacity factor of 30%, which is very close to the Company's entirely unrealistic value of 29.8%. which I discussed in my direct testimony.[38] In the other two, Mr. Teti uses a more realistic 20% capacity factor. There is no sourcing for either of these values, and no explanation for why he uses 30% in two scenarios and 20% in the other two scenarios.

This discrepancy in capacity factor directly contributes to the next issue. Mr. Teti uses Scenario 1, titled "PPL", as a baseline for his analysis, which has a likelihood of 10% (the lowest of the four scenarios), and a new project completion rate of 50% along with a capacity factor of 30% (the highest of the four scenarios). PPL's default cancellation rate assumption is 36%, so it is unclear why Mr. Teti increased this further to 50%. Regardless, because the "baseline" represents the most unlikely scenario with the highest completion rate and highest capacity, Scenario 1 has the largest amount of net metering generation of any scenario.

The other three scenarios (i.e., Scenario 2 - Low Shortage Risk, Scenario 3 - Med Shortage Risk, and Scenario 4 - High Shortage Risk) have either lower completion rates, lower capacity factors, or both. The result is they produce fewer MWh of net metering, which in turn means that the supplier is always "short" as shown in Row M of Figure 4. Per the schedule, the three non-baseline scenarios produce shortages between 2,102 MWh and

[37] Perhaps Mr. Teti was attempting to only include in this calculation a portion of BTM DG generation that is exported in real-time to the grid, but that ignores the primary focus on FTM DG systems in addition to being inconsistent with net metering energy accounting within the energy year.

[38] See, Lucas Direct at 40:7-44:9.

10,775 MWh, and Mr. Teti assumes the corresponding shortage costs must be priced into the DSP suppliers' bid. Because the final step divides the total cost of baseline and "shortage" purchases by the original net energy demand of 475,034 MWh, any shortage in net metering generation drives the "rate requirement" cost up. The final probability-weighted price is $73.52/MWh, which is $1.02/MWh higher than the assumed baseline supplier cost of $72.05/MWh. Per Mr. Teti, this is the "risk premium" that occurs due to the "inefficiency" of a DSP process that includes FTM DG projects in the GSC-1 class.

Q29. WOULD YOU HAVE APPROACHED THIS ANALYSIS IN THE SAME WAY?

A29. No, I would not have. It is highly unlikely that a DSP supplier will simply take as gospel PPL's net metering estimate, particularly one that includes such obvious flaws as the Company's capacity factor assumption. Even Mr. Teti gave this scenario a 10% likelihood, demonstrating his own doubt on the combination of project completion rate and capacity factor. But because of the high net metering generation starting point, all other scenarios result in "shortages" that drive up the price.

A better approach would be to take a more central, "expected" net metering capacity factor and completion rate. One could then assume higher and lower generation based on the observed variation in historical weather patterns in PPL's territory. One could also assume higher or lower completion rates depending on the policy and market outlook for FTM DG projects, although these probabilities would be necessarily speculative.

Q30. IF YOU PERFORMED THESE STEPS, HOW WOULD THE ANALYSIS ABOVE CHANGE?

A30. If one used a reasonable estimated average value for the capacity factor and completion rate, and included scenarios that represented symmetrical variations above and below these figures based on expected variability, then the resulting weighted-average price would be exactly equal to the original price. That is, there would be no risk premium because the original bidders would have all made the same rational analysis and reached the same conclusion based on the most likely outcome.

Mr. Teti's analysis only produces a positive risk premium because he starts with the scenario with the highest generation that necessarily causes all other scenarios to be short. This is easily validated by changing the capacity factor of the first scenario to lower values than the other scenarios. Now, without changing anything else, all other scenarios result in an energy surplus, which in turn means the final probability-weighted price would be lower than the original value. For instance, dropping the capacity factor of the PPL Scenario 1 to 15% would result in a final price of $71.11/MWh, more than a dollar below the original price.[39] The end result is no positive risk premium.

Q31. DO YOU THINK THIS RESULT IS MORE APPROPRIATE?

A31. No, it is equally as arbitrary in the opposite direction. Rather, it shows that Mr. Teti's analysis does not demonstrate that a DSP supplier would always embed a positive risk premium into their bids due to net metering generation variation. If it were always – and only – the case that the actual amount of net metering generation was lower than the Company's estimate, and DSP suppliers blindly accepted and used PPL's estimates without doing their own due diligence, perhaps that could result in this type of simplistic bidding. But one would expect DSP suppliers bidding on nine-figure annual energy procurements to be more sophisticated and the competitiveness of the bidding process to result in bids that are reflective of more reasonable assumptions and realistic scenarios.

Q32. HOW DOES THE ANALYSIS CONTINUE ONCE IT ESTABLISHES THIS "RISK PREMIUM"?

A32. Mr. Teti then takes the higher cost of the GSC-1 procurement from his risk premium analysis (rounding the $1.02/MWh risk premium down to $1.00/MWh) and calculates a before/after schedule for the status quo and MRPL proposal. In this schedule, reproduced below in Figure 5, Mr. Teti purports to show a $500,000 overall reduction in the "effective" DSP procurement cost under the MRPL proposal, all of which was captured in the GSC-1 class.

[39] This calculation includes a correction to the generation formula that uses 8,760 hours instead of 4,380 hours.

MAXIMUM REGISTERED PEAK LOAD (MRPL) - NUMERICAL EXAMPLE

			[1] Status Quo	[2] MRPL Proposal	[3] = [2] - [1] Difference
	GSC-1 SCI				
[A]	Gross Load (w/ Losses)	*MWh*	500,000	500,000	0
[B]	Net Metering (DSP Adjustment)	*MWh*	(25,000)	0	25,000
[C] = [A] + [B]	**GSC-1 SCI Procured Amount**	*MWh*	**475,000**	**500,000**	**25,000**
[D]	Weighted Price	*$/MWh*	**$ 73.50**	**$ 72.50**	$ (1.00)
[E] = [C] x [D]	GSC-1 SCI Procurement Cost	*$*	$ 34,912,500	$ 36,250,000	$ 1,337,500
[F]	AEC	*$*	$ 1,000,000	$ 1,000,000	$ -
[G] = [E] + [F]	**Procurement + AEC Cost**	*$*	**$ 35,912,500**	**$ 37,250,000**	**$ 1,337,500**
[H]	Customer Load (w/out Losses)	*MWh*	425,000	425,000	-
[I] = [G] / ([H] x 1000)	Rate	*$/kWh*	$ 0.08450	$ 0.08765	$ 0.00315
	GSC-2				
[J]	Gross Load (w/ Losses)	*MWh*	250,000	250,000	0
[K]	Net Metering	*MWh*	0	(25,000)	(25,000)
[L] = [J] + [K]	**GSC-2 Procured Amount**	*MWh*	**250,000**	**225,000**	**(25,000)**
[M]	Capacity Price	*$/MWh*	$ 30.00	$ 30.00	$ -
[N]	Energy Price	*$/MWh*	$ 40.00	$ 40.00	$ -
[O] = L x ([M] + [N])	GSC-2 Procurement Cost	*$*	$ 17,500,000	$ 15,750,000	$ (1,750,000)
[P]	AEC	*$*	$ 500,000	$ 500,000	$ -
[Q] = [O] + [P]	**Procurement + AEC Cost**	*$*	**$ 18,000,000**	**$ 16,250,000**	**$ (1,750,000)**
[R]	Customer Load (w/out Losses)	*MWh*	215,000	215,000	-
[S] = [Q] / ([R] x 1000)	Rate	*$/kWh*	$ 0.08372	$ 0.07558	$ (0.00814)
	Customer-Generator Compensation				
[T] = [B] + [K]	Net Metering	*MWh*	25,000	25,000	0
[U] = [D] or ([M] + [N])	Compensation Rate	*$*	$ 73.50	$ 70.00	$ (3.50)
[V] = [B] x [U]	E Factor Reconciliation - GSC-1	*$*	$ 1,837,500	$ -	$ (1,837,500)
[W] = [K] x [U]	E Factor Reconciliation - GSC-2	*$*	$ -	$ 1,750,000	$ 1,750,000
	Total				
[X] = [G] + [V]	Effective GSC-1 Cost	*$*	$ 37,750,000	$ 37,250,000	$ (500,000)
[Y] = [X] / ([H] x 1000)	*Effective GSC-1 Rate*	*$/kWh*	*$ 0.08882*	*$ 0.08765*	*$ (0.00117)*
[Z] = [Q] + [W]	Effective GSC-2 Cost	*$*	$ 18,000,000	$ 18,000,000	$ -
[AA] = [Z] / ([R] x 1000)	*Effective GSC-2 Rate*	*$/kWh*	*$ 0.08372*	*$ 0.08372*	*$ -*
[AB] = [Y] + [AA]	Effective GSC-1 + GSC-2 Cost	*$*	$ 55,750,000	$ 55,250,000	$ (500,000)

Figure 5 - OCA Exhibit ZT-1R Page 1

Q33. WHERE DOES THE $500,000 IN SAVINGS IN THE GSC-1 CLASS COME FROM?

A33. Although it is not immediately obvious from Mr. Teti's schedule, it comes entirely from the incremental $1.00/MWh price premium that is assumed in the Status Quo over the MRPL proposal. Under the MRPL Proposal, this $1.00/MWh is saved on the procured 475,000 MWh and later not spent on the 25,000 MWh of net metering energy payments that is recovered through the E Factor Reconciliation step. This can be demonstrated by reducing

the Status Quo weighted price of $73.50/MWh, highlighted in purple, to be equal to the $72.50/MWh in the MRPL proposal. If this is done, the workpaper will show identical results in the final line and no savings from the proposal.

Q34. GIVEN YOUR PRIOR POINT ABOUT THE RISK PREMIUM NOT BEING BASED ON A SOUND ANALYSIS, WHAT DO YOU CONCLUDE ABOUT MR. TETI'S ANALYSIS?

A34. I do not believe his analysis supports the MRPL proposal. The entirety of the MRPL proposal savings is predicated upon a positive risk premium, which itself only exists in the schedule because of entirely unrealistic baseline assumptions and a one-way ratchet towards net metering generation shortfalls. The schedule could easily be modified with equally unlikely assumptions about the amount of net metering generation being unrealistically low and producing a result showing the MRPL proposal *increasing* GSC-1 procurement costs over the status quo.

Q35. WHAT IS THE FUNDAMENTAL DISCONNECT BETWEEN MR. TETI'S AND THE COMPANY'S ANALYSIS AND THE ACTUAL DSP PROCUREMENT PROCESS?

A35. The fundamental disconnect comes from the assumption that DSP suppliers procure and charge customers for energy that they do not produce, and that this in turn causes an irreversible cycle of rate increases. In the Company's analysis, it held constant procurement expenses while simultaneously and dramatically increasing FTM DG generation that would necessarily reduce those expenses, causing the GSC-1 rate to increase substantially. To Mr. Teti's credit, he at least reduced the DSP procurement costs for net metering (adjusting purchases from 500,000 MWh to 475,000 MWh to reflect the 25,000 MWh of net metering generation) but still calculated changes in rates based on a static 425,000 MWh of customer load.

Once the price premium between the two scenarios is eliminated, the resulting change in the GSC-1 rates in Mr. Teti's schedule is lower than the Company's, but it is still an artifact of timing and not of the underlying total cost to provide service. As long as DSP suppliers bid based on reasonable estimates of NEM generation that are not unilaterally biased in a single

direction, there is no difference between the status quo and the MRPL proposal as Mr. Teti's schedule results in identical costs and rates once the E Factor reconciliation is incorporated.

Q36. DOES THIS CONCLUDE YOUR TESTIMONY?

A36. Yes, it does. However, I reserve the right to file such additional testimony as may be necessary or appropriate.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	
Coalition For Affordable Utility Services	
And Energy Efficiency in Pennsylvania	Docket Nos.
Office of Small Business Advocate	R-2025-3057164
Brad and Jennifer Woolley	C-2025-3057844
	C-2025-3057889
v.	C-2025-3057946

PPL Electric Utilities Corporation

VERIFICATION

I, Kevin Lucas, hereby declare that I am the Vice President, Policy Analysis of Solar Energy Industries Association; that, as such, I am authorized to make this verification on their behalf; that the facts set forth in the foregoing Surrebuttal Testimony are true and correct to the best of my knowledge, information and belief, and that I make this verification subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Date: February 9, 2026

By: /s/ Kevin Lucas
Kevin Lucas, Vice President, Policy Analysis
Solar Energy Industries Association

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2025-3057164
v.	:	
	:	
PPL Electric Utilities Corporation	:	
	:	

Solar Energy Industries Association and the Coalition for Community Solar Access, the "Joint Solar Advocates"

Statement No. 2

Direct Testimony of
Justin R. Barnes

Topics Addressed: Customer Generators in Pennsylvania, PPL's Maximum Registered Peak Load Proposal

Date: December 22, 2025

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Appendix A- Glossary of Terms

DIRECT TESTIMONY OF JUSTIN R. BARNES

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name, position, and business address.

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 203, Cary, North Carolina, 27511.

Q. By whom are you employed and in what capacity?

A. I am employed by EQ Research LLC as its President. EQ Research provides energy-related research and consulting services, which include subscription-based activity tracking services as well as customized reports, analysis, and expert testimony.

Q. On whose behalf are you submitting testimony?

A. My testimony is provided on behalf of the Solar Energy Industries Association ("SEIA") and the Coalition for Community Access ("CCSA"), jointly called the Joint Solar Advocates ("JSA") in this proceeding.

Q. Have you previously submitted testimony before the Pennsylvania Public Utility Commission ("PaPUC" or "Commission")?

A. No.

Q. Please describe your educational and occupational background.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at North Carolina State University for more than five years as a Policy Analyst and Senior

Policy Analyst.[1] During that period I worked on the Database of State Incentives for Renewables and Efficiency ("DSIRE") project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst, became the Director of Research in 2015, and President in 2023. In my current position, I oversee, coordinate, and contribute to EQ Research's various state clean energy policy subscription products and oversee and perform customized research and analysis to fulfill client requests. My Curriculum Vitae is attached as JRB Exhibit-1.

Q. Please summarize your relevant experience as it relates to this proceeding.

A. My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time, I have reviewed and evaluated trends in energy regulatory policy as well as other aspects of ratemaking relevant to distributed generation ("DG") such as cost of service, rate design, and the value of DERs. I use the term DERs generally to encompass customer-sited generation resources like rooftop solar, as well as community solar, battery storage, and load flexibility technologies.

I have submitted testimony before utility regulatory commissions in Colorado, Georgia, Hawaii, Indiana, Kentucky, Michigan, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Oklahoma, South Carolina, Texas, Utah, Virginia, West Virginia, and Wisconsin, as well as to the City Council of New Orleans, on various issues related to DER policy, net metering, rate design, and cost of service. These proceedings have involved a mix of general rate cases and other types of contested cases.

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

JRB Exhibit-1 contains summaries of the subject matters I have addressed in each of these proceedings.

Q. Please briefly describe the issues that you address in your testimony.

A. My testimony addresses a proposal by PPL Electric ("PPL" or "the Company") for tariff changes that would modify the peak load measurement that determines whether a customer receives default supply service under Rider GSC-1 or Rider GSC-2, the default supply rate riders for PPL's non-shopping customers. Specifically, the Company proposes to modify the determination of a customer's "maximum registered peak load" ("MRPL") so that the measurement includes energy flows from a customer-generator into the grid rather than only flows to the customer from the grid. This change would have profound implications for net energy metering ("NEM") customers whose generation system is not attached to an on-site load that offsets most or all of the electricity generated by the alternative energy system. I refer to these types of systems and customers throughout my testimony as "FTM DG" (front-of-the-meter distributed generation). Note that these FTM DG generating facilities are "alternative energy systems" under the Alternative Energy Portfolio Standards Act ("AEPS Act").

The effect of this change would be to shift these FTM DG customers from PPL's small commercial GSC-1 class to the GSC-2 class, which in turn would significantly reduce the compensation those customers receive for excess NEM generation at the Price to Compare ("PTC") at the end of the yearly billing cycle, often referred to as "cash-out." The Company contends that such a change is needed because compensation for excess generation to FTM DG customers produces upward rate pressure on the small commercial GSC-1 rate, which it projects could increase dramatically in the future based on the claimed

volume of interconnection requests from FTM DG generators that are pending in its interconnection queue.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to oppose PPL's proposal, and present an alternative approach to addressing the issue of GSC-1 rate impacts associated with FTM DG customers that provides equitable protections of the interests of both GSC-1 customers (*i.e.*, avoiding negative rate impacts) and existing and prospective FTM DG customers that have made (or will make) significant capital investments under the AEPS Act and the PaPUC's current orders and regulations applicable to customer-generators and NEM. My alternative approach is based on correcting the significant flaws in PPL's analysis and characterization of the situation, which entirely disregards the reality that excess NEM generation from FTM DG customers produces actual cost savings for GSC-1 customers that offset PPL's costs of compensating FTM DG customers for their excess generation. My testimony demonstrates that the dual objectives of protecting both GSC-1 small commercial customers and FTM DG project owners can be accomplished by:

1. Ensuring that PPL appropriately reflects the value of excess NEM generation in its determination of the GSC-1 default supply and transmission loads in order to realize those values for the benefit of the GSC-1 class.
2. Making a small adjustment to the GSC-2 rate to render the excess generation compensation due to FTM DG projects cost-based.
3. Establishing legacy rights, or grandfathering, under the GSC-1 rate classification for a segment of FTM DG customers with operational or mature planned projects.

Q. How is your testimony organized?

A. My testimony consists of the following sections:

Section II provides additional background information and an explanation of the PPL "problem" that underlies the objective of the Company's MRPL proposal.

Section III provides my analysis of the cost savings value that FTM DG projects provide, how the cost savings associated with these projects are or are not reflected in small commercial rates, and a comparison to the cost of compensating FTM DG projects for their excess generation at the small commercial GSC-1 PTC.

Section IV explains how PPL's present practices for determining PTC compensation for excess NEM generation under the GSC-2 rate are unreasonable because PPL excludes the generation capacity cost component of supply costs from the cash-out rate.

Section V presents my proposal, and the related justifications, for establishing GSC-1 legacy rights for FTM DG customers with operational projects and certain prospective FTM DG customers. The legacy rights for prospective FTM DG customers would only be available for projects that: (i) meet certain maturity and financial commitment milestones, and (ii) provide alternative energy credits ("AECs") to PPL at no cost.

Section VI contains my concluding remarks and recommendations.

Q. Please summarize your specific recommendations to the Commission.

A. I recommend that the Commission adopt my proposed approach for addressing issues associated with FTM DG customers, which consists of the following elements:

- The Commission should direct PPL to modify how it determines customer peak loads for the purposes of generation capacity and transmission cost allocation to: (i) allow those values to reflect "negative loads" (as described further below) produced by FTM

DG customers, and (ii) apply the cost savings benefits of those negative loads to reduce the allocation of the relevant costs to the rate class in which the FTM DG customer resides.

- The Commission should direct the Company to improve alignment of the GSC-2 rate with cost causation by allowing customers to register "negative peak loads" (as described further below) and revise the PTC-based compensation for excess NEM generation to include a credit for any FTM DG customer with a negative peak load value.
- The Commission should adopt my proposal for establishing legacy rights under the GSC-1 rate for all FTM DG projects that are operational or under construction as of the date of PPL's rate filing application.
- The Commission should adopt my proposal for establishing legacy rights under the GSC-1 rate for a subset of planned but not operational FTM DG projects that meet certain maturity and financial commitment milestones, conditioned on the FTM DG project owner also agreeing to surrender AECs produced by the project to PPL at no cost for the duration of the legacy rights term.

Q. Please identify any exhibits you are sponsoring.

A. I am sponsoring the following Exhibits and including a Glossary of Terms, attached to this testimony as Appendix A:

- JRB Exhibit-1, Justin Barnes Experience and Qualifications
- JRB Exhibit-2, JSA II-19
- JRB Exhibit-3, JSA IV-3(b)
- JRB Exhibit-4, JSA IV-3(b) and (c).

- JRB Exhibit-5, ComEd IL PJM OATT Attachment M-2.
- JRB Exhibit-6, ComEd IL response to the FERC regarding proposed changes to its PJM OATT Attachment M-2.
- JRB Exhibit-7, JSA II-10, Attachment 1.
- JRB Exhibit-8, Summary of NEM Legacy Rights provisions established in other states.
- JRB Exhibit - 9, JSA I-23 Attachment 1
- JRB Exhibit-10, JSA IV-2(c).
- JRB Exhibit -11, JSA IV-2(b).

II. DEFINING THE PROBLEM PPL SEEKS TO ADDRESS

Q. Please outline the basic "problem" that PPL's proposal is intended to address.

A. All NEM customers are entitled to receive compensation for generation in excess of their annual energy use at the PTC rate applicable to the customer class of which they are a part. This compensation is distributed on an annual basis which, as noted earlier, is referred to as the "cash-out" throughout my testimony. The Company recovers the cost of paying NEM cash-outs as an adder to its default supply rates, which is also allocated to the customer's default service rate class. Presently, FTM DG customers primarily fall within the small commercial segment of the default service GSC-1 rate classification, so the associated cash-out costs are borne primarily by the small commercial rate class. This dynamic creates the potential for upward pressure on the small commercial GSC-1 rate if the PTC cash-out rate is higher than the value of that excess generation as an offsetting cost reduction. Therefore, the core question is one of value of excess generation to GSC-1 customers vs. the cost, which can be defined as the difference between the rate ($/kWh)

paid for cash-out and the value of the excess generation. To be clear, there are a number of other important aspects and questions, but it is important to not lose sight of the fact that the basic dynamic is governed by cost and value.

Q. What are the other important aspects concerning FTM DG customers as part of the GSC-1 rate classification?

A. From the perspective of GSC-1 customers, the additional important aspects revolve primarily around questions of scale, which are central to examining any GSC-1 rate impacts that arise from a value/cost discrepancy. For instance, how large is the spread between cost and value rates? How much excess FTM DG generation is there expected to be in the future? How does the scale of excess generation compare to the size of the small commercial GSC-1 rate class? JSA Witness Lucas in JSA Statement No. 1 provides a detailed review and critique of the Company's assessment of potential rate impacts associated with the presence of FTM DG customers in the small commercial GSC-1 class, demonstrating numerous ways in which the Company's analysis is highly flawed. My own analysis reflects corrections to the Company's approach.

From the perspective of FTM DG generators, the critical questions are: (i) which, if any, FTM DG customers should be permitted to remain part of the GSC-1 rate classification, giving due consideration to potential rate impacts on other GSC-1 customers, and (ii) whether the design of the GSC-2 would appropriately compensate at full retail value any FTM DG customers that are not permitted to take GSC-1 service for their excess generation and, if not, the changes necessary to ensure fair, cost-based compensation.

Q. Where do all of these considerations lead to in defining a "Problem" Statement?

A. I define the Problem Statement as follows:

What solution or solutions would best balance the interests of, and provide equitable protections to, both GSC-1 customers and FTM DG customers, giving weight to the objectives of: (i) mitigating any significant rate impacts on GSC-1 customers, and (ii) respecting significant investments made or to be made by FTM DG customers that relied on (or are likely to rely on) existing rules when making those investments?

When thinking about FTM DG generators and questions concerning "scale" of impacts under different solution approaches, I think it is helpful to separate FTM DG customers into the following basic categories and characteristics:

1. Already operational or under construction projects (relatively small in volume in aggregate, already fully financially invested in a given project);
2. Projects presently in PPL's interconnection queue (significant potential volume, but with a varying level of development, maturity, sunk investment costs, and probability of success even without PPL's proposed changes); and
3. Future projects not presently in PPL's interconnection queue (unknown volume, minimal or no sunk investment costs).

Of these three project categories, Category 2 (planned projects) presents by far the most challenging set of circumstances for arriving at equitable solutions.

III. VALUE OF EXCESS GENERATION FOR DEFAULT SERVICE PROCUREMENT

A. *Excess Generation Reduces Costs that Determine the GSC-1 PTC*

Q. Please briefly describe the PTC and its components.

A. The PaPUC's regulations define the PTC as "[a] line item that appears on a retail customer's monthly bill for default service. The PTC is equal to the sum of all unbundled generation and transmission related charges to a default service customer for that month of service." 52 Pa. Code § 69.1803. PPL's PTC basically consists of default generation

supply costs for energy and generation capacity via the GSC ("Generation Service Charge") component, and transmission costs via the separate Transmission Service Charge. The design of the GSC component differs between GSC-1 and GSC-2, but is the same, a flat volumetric rate, for the transmission service charge.

Q. Has the Company performed an evaluation of how NEM excess generation affects generation supply and transmission costs?

A. Yes, but only in an incomplete and consequently biased manner. The Company's assessment of potential rate impacts on GSC-1 customers as a result of FTM DG excess generation considers only the costs of cash-out compensation. PPL fails to reflect that excess generation produces actual and readily quantifiable cost reductions that offset those costs. JSA Witness Lucas in JSA Statement No. 1 addresses the quantification of this error, and several others, in the Company's GSC-1 rate impact projections in detail.

Q. Please explain how excess generation reduces the generation supply costs that feed into the PTC for small commercial GSC-1 customers.

A. Each kWh of excess generation reduces supply costs at the prevailing weighted average supply rate for any given period. This is because the Company accounts for excess generation by reducing the monthly supply load that determines what it owes to suppliers for load-following contracts.[2] At the same time, PPL does not reduce the retail sales volume that is used to translate supply costs into the GSC-1 retail rates in an equivalent manner. Consequently, the actual supply costs that the Company incurs are lower than they would otherwise be absent the excess generation, but the volume of retail sales over which the cost is allocated remains the same, producing a lower retail rate.

[2] The small commercial GSC-1 supply contracts consist exclusively of load-following contracts.

Q. Can you illustrate how the rate impact functions with a simple example?

A. Yes. Assume that monthly small commercial GSC-1 supply load is 100 million kWh at an average cost of $0.0800/kWh, a total cost of $8 million. Excess generation of 1 million kWh is applied to reduce the supply load to 99 million kWh, which reduces the total cost by $80,000 to $7.92 million. However, when calculating the retail rate, retail sales are not adjusted to reflect excess generation so retail sales stay at 100 million kWh. The resulting retail rate is then lower at $0.0792/kWh rather than $0.0800/kWh.

Q. What evidence is there that the scenario you just described is an accurate reflection of how NEM excess generation affects PPL's generation supply costs?

A. The Company has expressly stated that it applies NEM excess generation in this fashion as a reduction in supply loads for load-following contracts.[3] The specific impacts are also visible in the materials that the Company has provided documenting the underlying rate calculations for determining the small commercial GSC-1 rate.[4]

Q. Is this same supply cost reduction effect reflected in wholesale default service supplier's cost of serving small commercial GSC-1 load?

A. No. It does not appear to be, at least in a complete and equivalent manner because PPL does not allow customers to be assigned negative load and negative capacity costs, as I describe further below. By way of further explanation, at a high level, a wholesale default service supplier's costs are generally determined by the energy use and peak demands of the customers they serve at market energy and capacity prices.[5] Therefore, the

[3] JRB Exhibit – 2, JSA II-19.

[4] Company response to JSA III-16 Confidential Attachment 1.

[5] In practice, wholesale default service suppliers are likely to engage in a variety of strategies to manage their costs so their costs do not exactly replicate market prices. Nevertheless, market prices present a good benchmark for the purpose of evaluating relative costs of load and the value of load reductions.

determinants of a wholesale supplier's costs are: (i) the aggregate hourly energy use of their customers (typically termed the Hourly Energy Obligation) for energy, and (ii) the aggregate peak load contribution ("PLC") of their customers for generation capacity.[6] A customer's PLC is based on its demand (kW) at the time of the top 5 PJM-wide peak demand hours during the prior summer ("PJM 5CP"). Accordingly, if a customer reduces its PLC by virtue of lowering its load during the PJM 5CP hours, that customer is providing capacity cost savings to their default service wholesale supplier.

But what this general construct leaves out is the fact that an FTM DG customer is likely to have negative demand during the PJM 5CP hours. In other words, they are exporting electricity to the distribution grid rather than pulling electricity from the grid, which makes their demand "negative." In that case, a FTM DG customer should have a negative capacity cost for a supplier, but PPL's practices for reporting customer load and PLCs to PJM do not allow a customer to generate a negative PLC.[7] Rather, a customer exporting power at the time of a PJM 5CP hour is assigned a zero load during that hour, and the supplier's capacity costs for an aggregated tranche of GSC-1 load would not be reduced by the negative load.

Q. How does the Company justify its practice of not allowing customers to have a negative PLC?

A. PPL stated in response to discovery that a customer cannot have a negative PLC because the Company's PJM OATT (Attachment M-2) does not allow for a negative amount.[8]

[6] A customer's PLC is often referred to as their "capacity tag."
[7] JRB Exhibit-3, JSA IV-3(b).
[8] JRB Exhibit-4, JSA IV-3(b) and (c).

Q. Please explain what exactly Attachment M-2 is in the context of PPL's membership in the PJM.

A. Each PJM member utility has an Open Access Transmission Tariff ("OATT") approved by the Federal Energy Regulatory Commission ("FERC") that details the numerous terms of their membership. Each utility's OATT contains an Attachment M-2, which establishes the protocols for determining customer PLCs through which generation suppliers within a member's PJM zone are assigned the generation capacity and transmission costs for the customers they serve in the PJM settlement process.[9] As the entity that actually performs customer metering, a distribution utility like PPL performs the requisite calculations to assign each customer a PLC. Those customer-level PLC values are then aggregated at the supplier level by PPL and distributed to the PJM. In general, the practices identified in each utility's Attachment M-2 are similar, but they are not necessarily identical. That is, each utility's protocols are of their own design but must be reviewed and approved by the FERC.

Q. Do you agree with the Company's claim that negative PLCs are not permitted by PPL's Attachment M-2 to its OATT?

A. No. I have reviewed PPL's Attachment M-2 and see nothing that precludes a customer from being designated with a negative PLC. There are no references to negative amounts being prohibited, or any other statements indicating that a customer's PLC must be a positive number.

[9] Attachment M-2 also addresses PLC determinations from the standpoint of transmission cost assignment.

Q. Are there any broader PJM rules that prohibit a customer from having a negative PLC?

A. No. On the contrary, at least one utility in PJM, Commonwealth Edison in Illinois ("ComEd"), has received FERC approval for an Attachment M-2 to its OATT that *expressly* permits the use of negative PLCs for NEM and community solar customers. ComEd Attachment M-2 to its OATT is attached as JRB Exhibit-5.

Q. Please elaborate on the origins and use of negative PLCs for NEM customers by ComEd.

A. In March 2022 ComEd sought FERC approval for revisions to its PJM OATT Attachment M-2 in compliance with Illinois law requiring it to improve its cost allocation methodology to ensure that suppliers with customers that install NEM systems or who develop community solar projects receive the generation capacity and transmission cost reductions produced by those systems. This objective required a change to ComEd's Attachment M-2 to eliminate the existing zero floor value on individual customers' capacity and transmission PLC values to allow those values to be negative.

The FERC subsequently questioned several aspects of ComEd's filing in a deficiency letter, among other things whether PJM rules permit the establishment of negative PLCs. In response, ComEd explained that PJM rules only prohibit negative capacity values at the aggregated supplier level, not the individual customer level. In other words, a supplier can have individual customers with negative PLCs so long as their aggregate supply load remains positive. For example, a supplier could have customers with negative PLCs totaling 50 MW, but as long as that same supplier also had other

customers with PLCs summing to an amount greater than 50 MW, the supplier's aggregate peak load would be positive and therefore permissible under PJM rules.

The FERC accepted this explanation and approved the change effective September 1, 2022. JRB Exhibit-5 provides ComEd's approved OATT Attachment M-2, which includes the following clause:

> For purposes of this Attachment M-2 (ComEd), load attributable to net metering and community supply projects may reflect both consumption and generation in the CPLC, and therefore can result in a positive or negative value for any such individual customer's calculation.[10]

JRB Exhibit-6 provides ComEd's response to FERC's deficiency letter. ComEd's response includes a further explanation regarding PJM's rules governing PLC determinations, the cost of service-based justification for the change, and example calculations of how PLCs that may include a negative value would be accomplished. Among other things, ComEd stated in its response:

> PJM's peak load forecast recognizes the value of net metering and community solar projects by reducing the peak demand forecasted for ComEd's zone. When PJM procures capacity, it does so on the basis of that reduced peak demand calculation. This peak demand reduction, and the resulting reduction in the cost of capacity procured, inures to the benefit of all customers in the ComEd zone. Nevertheless, net metering customers and community supply projects that produce more energy than they use during the five highest daily peaks may fail to receive the full value of providing that reduction because their contribution is artificially limited to zero.[11]

[10] JRB Exhibit-5, p. 3.
[11] JRB Exhibit-6, p. 5.

Q. What should the Commission conclude regarding PPL's assertion that negative PLCs cannot be utilized for FTM DG customers?

A. The supposed limitation is one of PPL's own making, and one which prevents FTM DG customers from receiving the full value of providing generation capacity cost reductions via their contribution to reducing demand during the PJM 5CP hours.

Q. What are the implications of PPL's practice of not allowing FTM DG customers to generate a negative PLC?

A. The result is supply costs for small commercial GSC-1 customers that are higher than necessary since wholesale suppliers to PPL cannot benefit from generation capacity cost reductions from FTM DG customers and reflect those cost savings in their bids to serve the small commercial GSC-1 class. That is, what the wholesale supplier receives in payments for serving a given tranche of small commercial GSC-1 load are reduced by excess NEM generation, but the generation capacity costs that the same wholesale supplier incurs are not reduced. That outcome at a large scale could produce different bidding behavior that increases default service supply costs for small commercial GSC-1 customers, which is inconsistent with the objective of least-cost procurement for default service supply required by the Alternative Energy Portfolio Standards ("AEPS") Act.

Q. Please explain how NEM excess generation can reduce GSC-1 transmission expenses reflected in the transmission service charge that is attached to a GSC-1 customer's underlying default service rate schedule.

A. For the purposes of the transmission service charge, PPL allocates its costs to individual rate classes according to class loads during the five highest zonal peak hours, or Zonal 5CP. The Zonal 5CP hours typically differ from the PJM 5CP hours because each transmission

zone has its own load characteristics, and the Zonal 5CPs can include non-summer hours. For instance, the Zonal 5CP hours could feature two hours that are also PJM 5CP hours, two other hours that are also during the summer but on different days or on the same day but at a different hour of the day than the PJM 5CP hours, and another non-summer hour (*e.g.*, an early morning winter hour). As a result, a customer's transmission PLC will not be the same as their generation capacity PLC. Nevertheless, an FTM DG facility can reduce costs allocated to the GSC-1 class by reducing the overall class load during the Zonal 5CP hours in the same manner that it can do so during the PJM 5CP hours. However, as with PLCs used to calculate generation capacity costs, realizing the cost savings benefits derived from those load reductions depends on PPL recognizing those negative loads and appropriately assigning them to the applicable rate class.

Q. Does the example you previously discussed regarding PPL's OATT Attachment M-2 also apply to the determination of transmission PLCs?

A. Yes. The ComEd example covers transmission PLCs as well as generation capacity PLCs. For clarity, in the ComEd example generation capacity PLCs are referred to as the capacity PLC ("CPLC") whereas transmission PLCs are referred to as the Network Service PLC ("NSPLC"). This difference in terminology reflects the distinction I previously described regarding PLCs based on the PJM 5CP hours (generation capacity) and Zonal 5CP hours (transmission).

Q. What are your recommendations to the Commission regarding the use of negative PLCs for FTM DG customers for the purpose of generation capacity and transmission cost allocation?

A. The Commission should direct PPL to allow negative PLCs in the interest of both cost-based ratemaking and least-cost default supply procurement.

Q. Would it be necessary for PPL to seek FERC approval to modify its Attachment M-2 to effectuate this recommendation?

A. I am not expressing a legal opinion on this issue, but note that ComEd did persuade FERC, despite PJM rules that prohibit negative capacity values at the aggregated supplier level, to accept negative PLCs at the individual customer level. A supplier can have individual customers with negative PLCs so long as their aggregate supply load remains positive. As I previously observed, I see nothing in PPL's current Attachment M-2 that precludes a customer from having a negative PLC. Having said that, an express provision addressing this detail, such the language now found in ComEd's Attachment M-2 (see JRB Exhibit-5) would add valuable transparency on the practice. The FERC's approval would presumably be ministerial in nature given that the FERC has already accepted an identical change to ComEd's Attachment M-2.

B. *Calculation of the Default Supply Value of Excess Generation*

Q. Please outline your general approach for developing an assessment of the value of NEM excess generation.

A. With respect to scope, my quantified value analysis covers four directly measurable cost savings categories: (i) energy, (ii) generation capacity, (iii) transmission, and (iv) AEPS Act compliance value (*i.e.,* Alternative Energy Credits or "AECs"). I additionally included

a sensitivity case reflecting the benefit of Demand Induced Market Price Effects ("DRIPE"), which constitutes a cost-savings benefit produced by FTM DG facilities, but which cannot be directly measured. Finally, I investigated one additional benefit, distribution cost savings that could arise from distribution upgrades funded by FTM DG customers, but did not develop a specific value for this benefit.

I approached the question of value from two perspectives, resulting in two scenarios. The first perspective/scenario is based on how PPL presently accounts for NEM excess generation by small commercial GSC-1 customers in its default service supply plan. This first scenario represents the present situation for small commercial GSC-1 customers. Second, I have developed a separate scenario and assessment based on a wholesale market value approach that reflects the value of NEM excess generation for a wholesale generation supplier that serves small commercial GSC-1 loads. This second scenario involves a situation in which a small commercial GSC-1 supplier is able to realize supply cost savings benefits in direct proportion to the wholesale value of FTM DG excess generation as a reduction in the load they are obligated to serve. Both perspectives include the same value for transmission cost savings that assumes that negative transmission peak load values from FTM DG customers are recognized and permitted, which produces cost savings for the small commercial GSC-1 class.

Q. Please describe your methodology for modeling FTM DG excess generation as an input to your supplier market value analysis.

A. I used annual weather-year specific values downloaded from the National Renewable Energy Laboratory's System Advisor Model ("NREL SAM") from 2022-2024 for a central location in PPL's service territory to establish representative solar generation profiles for

both a fixed-tilt solar system and a single-axis tracking system.[12] I have focused on solar NEM systems for the same reasons discussed by JSA Witness Kevin M. Lucas in JSA Statement No. 1. I adjusted the hourly solar profiles for each year to reflect daylight savings time ("DST") because the PJM convention for reporting wholesale market prices and peak hours states hours in prevailing time as adjusted for DST whereas NREL SAM profiles do not contain such an adjustment. I applied the adjusted hourly generation profiles for each year to the appropriate market price determinants for the December 2025 – May 2026 PTC period to generate an average monetary cost savings estimate ($). I then divided that amount by average total solar generation to produce a savings rate stated in terms of savings per kWh of annual solar generation ($/kWh). The specifics of my methodology from the standpoint of the individual value determinants are described further below.

Q. What is the significance of using weather-year specific solar generation values in your value assessment?

A. Solar production, peak hours, and energy market prices are weather dependent. Using weather-year specific solar generation values aligns the solar generation profile with the system conditions that existed during specific hours.

Q. Please summarize the results of your FTM DG excess generation value analysis.

A. The results of my analysis are shown in Table 1 below, varied based on whether the assessment uses a hypothetical fixed tilt solar system or a single-axis tracking system, and according to the two scenarios/perspectives I discussed above regarding: (i) PPL's current

[12] For a central location, I chose Berwick, Pennsylvania, which is roughly central in terms of east-west and north-south location within PPL's service territory. The NREL SAM profiles are provided in 30-minute increments, so I averaged those values for each hour to produce an hourly profile.

NEM excess generation accounting practices, and (ii) wholesale market value of NEM excess generation for a wholesale GSC-1 supplier.

Table 1: Value of Excess Generation Summary

Scenario – GSC-1 Customers		
Value Component	**Fixed Tilt**	**Single Axis**
Energy	\$0.08225	\$0.08225
Capacity		
Transmission	\$0.02842	\$0.02948
Sub-Total	**\$0.11067**	**\$0.11173**
AECs	\$0.02642	\$0.02642
Total With AECs	**\$0.13709**	**\$0.13815**
Scenario - GSC-1 Wholesale Suppliers		
Value Component	**Fixed Tilt**	**Single Axis**
Energy	\$0.04068	\$0.04076
Capacity	\$0.02995	\$0.03486
Transmission	\$0.02842	\$0.02948
Sub-Total	**\$0.09904**	**\$0.10509**
AECs	\$0.02642	\$0.02642
Total With AECs	**\$0.12546**	**\$0.13151**

Q. How does your excess generation value analysis compare to the costs associated with the cost of that excess generation in the form of the annual cash-out?

A. PPL's December 2025-May 2026 small commercial GSC-1 PTC rate is \$0.12681/kWh. Table 2 provides a comparison of this PTC value with the different value scenarios shown in Table 1. As illustrated in Table 2 there is a small gap between the market-based cost-savings value of FTM DG excess generation and the GSC-1 cash-out rate if AEC value is excluded. This is shown in Row 5 for the GSC-1 Customers scenario and Row 11 for the GSC-1 Wholesale Suppliers scenario. If AEC value is considered, the market value of NEM excess generation exceeds the cost of PTC cash-out compensation (*i.e.*, a net benefit) for a single-axis tracking system and is within roughly \$1/MWh for a fixed tilt system

(Row 12). In the GSC-1 customer scenario, with AECs included the value is positive for both a fixed tilt and single-axis tracking solar system (Row 6).

Table 2: GSC-1 PTC Rate Vs. NEM Excess Generation Value

Scenario - GSC-1 Customers			
Row	**Description**	**Fixed Tilt**	**Single Axis**
1	NEM Excess Value Without AECs	$0.11094	$0.11201
2	AEC Value	$0.02642	$0.02642
3	NEM Excess Value With AECs	$0.13736	$0.13843
4	December 25 - May 26 PTC Rate	$0.12681	$0.12681
5	Value Vs. PTC (Without AECs)	($0.01587)	($0.01480)
6	Value Vs. PTC (With AECs)	$0.01055	$0.01162
Scenario - GSC-1 Wholesale Suppliers			
	Description	**Fixed Tilt**	**Single Axis**
7	NEM Excess Value Without AECs	$0.09904	$0.10509
8	AEC Value	$0.02642	$0.02642
9	NEM Excess Value With AECs	$0.12546	$0.13151
10	December 25 - May 26 PTC Rate	$0.12681	$0.12681
11	Value Vs. PTC (Without AECs)	($0.02777)	($0.02172)
12	Value Vs. PTC (With AECs)	($0.00135)	$0.00470

Q. What should the PaPUC conclude from these comparisons?

A. With the conveyance of AECs from customer-generators to PPL, as I recommend be adopted as a condition of GSC-1 legacy rights eligibility for mature planned projects, the value of NEM excess generation to the GSC-1 rate class meets or exceeds the cost of providing cash-out compensation to FTM DG customers (Row 12 of Table 2). Accordingly, GSC-1 customers would not face any significant upward pressure on their rates under my proposal.

Q. Please explain how you calculated the combined energy and capacity value for the GSC-1 customer scenario and perspective.

A. This value is the load-weighted average price of existing supplier contracts that cover the December 2025 – May 2026 reference PTC period.[13] This reflects PPL's practice of reducing supply load by the amount of NEM excess generation, the result of which is that the costs borne by GSC-1 customers are reduced at the average contract price for the period in question (excluding administrative costs).

Q. Please describe your specific methodology for quantifying the generation capacity component in the second scenario, i.e., the market value calculation.

A. I mapped the annual solar generation profiles to the times of the PJM 5CP over three years from 2022-2024 to produce an estimate of FTM DG output at each of the peak hours (15 in total). I used the average output during those hours to calculate an average capacity contribution of an FTM DG generator to the peak hours and then grossed that amount up to reflect avoided transmission losses (roughly 2.68%). The resulting capacity value (kW) is then multiplied by the June 2025 – May 2026 PJM capacity rate for the PPL zone (roughly $99/kW) to produce a monetary ($) cost savings value. The cost savings rate calculated as that value spread across total generation, producing a volumetric ($/kWh) rate.

Q. Please describe your specific methodology for quantifying the transmission component in both scenarios/perspectives.

A. For transmission, I used the same capacity contribution methodology and transmission loss assumption but substituted PPL's Zonal 5CP hours for the PJM 5CP hours. The

[13] Based on the load weighted aggregation of data provided in PPL's response to JSA III-16 Highly Confidential Attachment 1.

transmission price is based on the 2026 Network Integration Transmission Service rate in the PPL zone, roughly $109/kW. I performed the volumetric savings rate calculation in the same manner as I did for generation capacity.

Q. Please describe your specific methodology for quantifying the energy component in the market value calculation, i.e., second scenario/perspective.

A. For energy value, I used the hourly real time PJM locational marginal price ("LMP") at the PPL Residual Aggregate Node (as referenced in PPL's tariff, GSC-2) from November 2024 – October 2025 as the relevant energy price metric. This is the same rate that GSC-2 customers currently pay for energy. The cost savings value is calculated for each hour of the year by: (i) multiplying the hourly FTM DG generation profile by the hourly price to produce a monetary value for each hour, (ii) summing those hourly monetary values for the entire year, and (iii) dividing the result by to annual generation to produce a cost savings rate. I performed this calculation using each of the annual (2022-2024) FTM DG generation profiles and averaged those three rates to produce the amount shown in Table 1.

Q. Do you have any further comments regarding the energy value calculation?

A. Yes. The energy value calculation presents a unique challenge because unlike generation capacity and transmission prices, 2026 energy prices are not yet known. Furthermore, PJM energy prices have escalated considerably over the last year, so relying on prices from past years to produce a comparison with the December 2025-May 2026 PTC cash-out rate would be an apples-to-oranges comparison. I selected the November 2024 – October 2025 time frame as a reasonable proxy for 2026 prices given that they cannot be known in advance. My use of a three-year average to calculate a final value reflects the fact that the

annual FTM DG profiles are not specific to this time frame. However, the resulting differences in the annual value estimates are small, a difference of only roughly $2-3/MWh between the highest and lowest annual estimates. Therefore, the energy value that I presented in Table 1 is a reasonable estimate for as yet unknown future energy market prices.

Q. Please describe your specific methodology for quantifying the AEC value component in both scenarios and why you included it in your value assessment.

A. The AEC value is based on the weighted average of solar AEC and Tier 1 AEC prices secured by PPL in its July 2025 AEC Request for Proposals.[14] I have included AEC value in my value assessment because my legacy rights proposal (discussed later in this testimony) for non-operational FTM DG facilities is conditioned on the FTM DG customer's agreement to transfer AECs to PPL at no cost for the duration of the legacy rights term.

The weighting uses the solar and Tier 1 compliance percentages, 0.5% and 7.5% respectively, applied to prices of $26.39/MWh for solar AECs and $26.42/MWh for Tier 1 AECs. The weighting reflects the fact that a portion of AECs from solar may be used to meet the solar AEC requirements and a portion used to meet Tier 1 AEC requirements. In practice, the weighting does not meaningfully affect the resulting average because the prices of Tier 1 AECs and solar AECs are nearly identical. However, this has not always been the case, and may not be the case in the future.

[14] PPL. DSP 6, Alternative Energy Credit Solicitation 1 Results. Available at: https://ppldsp.com/wp-content/uploads/2025/07/DSP6-AEC-Sol1-Results.pdf.

Q. Are there any further types of value that FTM DG customers may provide to other ratepayers?

A. Yes. I have identified two additional value streams: (i) Demand Reduction Induced Price Effects ("DRIPE") on broader wholesale market prices, and (ii) FTM DG customer payments for distribution reinforcements that avoid expenditures by PPL.

Q. Please explain the concept of DRIPE and how it relates to FTM DG facilities.

A. DRIPE is sometimes referred to as the Wholesale Market Price Effect. DRIPE arises from the fundamental economic dynamic between supply and demand in a competitive electricity market. In economic terms, supply and demand in combination can be represented by a price curve under which price changes in relation to the demand for a given good or service (*e.g.*, capacity or energy). Relatively higher demand causes higher prices, which in turn allows resources with higher costs to be profitable. In a competitive market, the highest priced resources set the clearing price (*i.e.*, marginal price) that all resources bid into the market receive. Reducing demand shifts the clearing price to a lower amount, producing cost savings for all entities that rely on that market for the product in question, energy or capacity. FTM DG generation produces such effects because it lowers the amount of demand that must be met by other resources. In other words, absent FTM DG, market prices would have been higher, which would result in higher default service supply costs.

Q. Do regulators in other states consider the cost savings benefits of DRIPE?

A. Yes. The Database of State Efficiency Screening Practices lists 10 states, several of which are in PJM, that incorporate DRIPE into their cost-effectiveness screening for energy

efficiency measures.[15] In 9 of these states, the effect is a monetized cost-savings benefit, while in one other state (New Jersey) a proxy 5% adder to capacity and energy savings value is used.[16] I am also aware that Illinois has historically considered DRIPE in its analysis of time-varying electricity pricing options.[17] Although these examples refer to energy efficiency screening, the impact of load reduction on wholesale prices is equally present for customer-sited solar. In addition, a 2025 literature review conducted by Lawrence Berkeley National Lab identified DRIPE as a benefit component included in recent value of solar studies in Connecticut and New Hampshire.[18]

Q. How did you address DRIPE in your wholesale market value scenario analysis?

A DRIPE is not included in the value results that I presented in Table 1 or Table 2 because: (i) unlike those values, it can only be inferred rather than directly measured, and (ii) performing a full DRIPE analysis is highly data intensive and complex. However, for illustrative purposes, Table 3 shows the value of DRIPE based on the 5% "proxy" adder method used in New Jersey.

Table 3: DRIPE Value Under 5% Proxy Adder Method

Component	Fixed Tilt	Single-Axis
Energy Value	$0.04068	$0.04076
5% DRIPE Adder	*$0.00203*	*$0.00204*
Capacity Value	$0.02995	$0.03486
5% DRIPE Adder	*$0.00150*	*$0.00174*

[15] *See* ACEEE, *Database of State Efficiency Screening Practices (DSP)*, https://www.aceee.org/database-state-efficiency-screening-practices (last accessed December 19, 2025).

[16] *Id.* The states where DRIPE is reflected as a monetizable benefit are: Connecticut, Delaware, District of Columbia, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, and Rhode Island. The methodology used in one further state, Tennessee, is not clear.

[17] *See* Illinois Commerce Commission, Docket No. 15-0602, Commonwealth Edison Company's Hourly Pricing - 2023 Annual Report, at 4 (Apr. 19, 2024), https://www.icc.illinois.gov/docket/P2015-0602/documents/350023.

[18] Sydney P. Forrester & Eric O'Shaughnessy, *A Review of Value of Solar Studies in Theory and in Practice*, at 28–29, Lawrence Berkeley National Laboratory (Jan. 2025), https://eta-publications.lbl.gov/sites/default/files/2025-02/20250206_final_vos.pdf.

Component	Fixed Tilt	Single-Axis
DRIPE TOTAL	$0.00353	$0.00378

The inclusion of DRIPE as a value component further enhances the value of excess NEM generation.

Q. Please further describe how FTM DG projects may produce distribution cost savings that benefit other ratepayers.

A. All FTM DG customers are obligated to pay in full for any distribution upgrades that are necessary to interconnect a facility to PPL's distribution system. These upgrades include a variety of system reinforcements, such as substation upgrades and higher capacity conductors, that are not included in the Company's distribution rate base but nevertheless may have been needed in the future to accommodate changes in customer load. Keeping those investments outside of the Company's rate base benefits all customers by reducing upward pressure on distribution rates. A portion of that cost savings benefit would inure to small commercial GSC-1 customers in relation to their proportional allocation of bulk distribution costs. The Company's data indicates that FTM DG customers have paid for more than $3 million in distribution grid reinforcements.[19]

Q. How do you recommend that the Commission further consider distribution benefits that arise from FTM DG projects?

A. It would be reasonable for the Commission to consider this type of distribution benefit as a qualitative factor in its evaluation of the impacts of FTM DG customers on small commercial GSC-1 customers.

[19] Based on an aggregation of Company's response to JSA III-7 Confidential Attachment 1.

IV. REFINEMENT OF GSC-2 RATE TO FAIRLY COMPENSATE FTM DG PROJECTS FOR EXCESS GENERATION

A. *Omitting the Generation Capacity Value Unreasonably Lowers the GSC-2 Cash-Out*

Q. Please briefly reprise the GSC-2 rate design and how it differs from the GSC-1 rate design.

A. The primary components of the GSC-2 rate are: (i) an energy charge based on the PJM real-time hourly LMP, and (ii) a capacity charge based on a customer's PLC and the prevailing PJM capacity price in PPL's zone.[20] As I previously explained, a customer's generation-related PLC is based on their demand (kW) at the time of the top 5 PJM-wide peak demand hours during the prior summer ("PJM 5CP"), meaning that it is customer-specific. Apart from administration costs, the GSC-2 rate is a pass-through of the costs of serving a load at prevailing wholesale market prices. This differs from the GSC-1 rate where energy and capacity costs are priced at a single volumetric rate based on fixed price offers from wholesale suppliers to PPL. Wholesale supplier offers reflect expected energy and capacity costs in an aggregated/bundled manner based on the supplier's expectation of future market prices and the accompanying cost of serving a given amount of load.

Q. How is the GSC-2 design reflected in the PTC used for NEM energy generation cash-outs?

A. For the energy component, PPL averages the real-time daily LMP over six month intervals. The transmission component is set at the same flat volumetric rate that a customer pays for energy consumption. The generation capacity component reflected in the capacity charge

[20] A customer's PLC is also commonly referred to as their "capacity tag."

portion of the GSC-2 supply rate is not included in the PTC cash-out.[21] So the basic difference between the GSC-1 and GSC-2 PTC cash-out rates is that the GSC-1 rate includes all PTC components priced at the same rate that a customer is charged for energy use, whereas the GSC-2 rate omits the generation capacity component.

Q. Why is the omission of the generation capacity component of the GSC-2 rate significant?

A. At present high PJM capacity prices, capacity costs are a significant portion of the costs associated with a customer's energy demands. Furthermore, it is already known that these high costs will persist, and in fact increase in the near future. For the 2025/2026 PJM planning year the capacity market cleared at a rate of roughly $270/MW-day in the PPL zone. The price increased to approximately $329/MW-day for the 2026/2027 PJM planning year and approximately $333/MW-day for the 2027/2028 PJM planning year, in both instances hitting an artificial price cap first imposed for the 2026/2027 auction.[22]

Q. Why is the omission of generation capacity component of the GSC-2 PTC cash-out rate unreasonable?

A. As I discussed in Section III(A) of my testimony, the omission stems from PPL's practice of not allowing a customer to register a negative PLC. Since the lowest PLC that is possible is zero, there is no basis for calculating a cash-out credit. This limitation deprives an FTM DG customer, and the GSC-2 wholesale default service supplier, of the cost savings benefits of generation produced during peak periods. In short, a negative capacity cost is a benefit provided by some customer-generators that is not taken into account by PPL in

[21] JRB Exhibit-7, JSA II-10, Attachment 1.

[22] *See* PJM. Capacity Market (RPM) results, available at: https://www.pjm.com/markets-and-operations/rpm.

the current construct of the GSC-2 rate. Furthermore, as I also explained in Section III(A), PPL's reliance on its PJM OATT Attachment M-2 to justify a zero floor value for customer PLCs amounts to a self-imposed limitation.

Q. What is your recommendation to the Commission regarding the calculation of the PTC cash-out rate for FTM DG customers?

A. The Commission should direct the Company to eliminate its practice of prohibiting a customer from having a negative PLC and implement a symmetrical credit within the cash-out structure for customers that register negative PLCs.

B. *Mechanics of Calculating a GSC-2 Capacity Credit*

Q. Please summarize how the inclusion of the generation capacity portion of supply costs for inclusion in the GSC-2 NEM cash-out rate would function.

A. Each FTM DG facility would receive a credit for negative PJM 5CP capacity contributions based on facility-specific interval metering, priced at the same capacity rate that generation capacity costs were charged for the applicable period. The credit amount would be set for each FTM DG facility in the same manner that the capacity charge is individualized for GSC-2 customers more generally. The calculation of the credit should also include an adjustment for transmission losses to reflect the fact that FTM DG excess generation displaces energy at the bulk generation level and therefore avoids transmission losses.

Q. Would the establishment of a generation capacity credit for the GSC-2 NEM cash-out rate involve any significant additional complexities?

A. No. PPL is already measuring PJM 5CP demands for the purpose of establishing customer capacity charges. The Company would simply be performing the same calculation for FTM DG customers, with the only difference being that negative 5CPs would be permitted,

and would result in a credit, *i.e.*, an increase in the GSC-2 cash-out rate, rather than a charge. To the extent that non-standard metering with incremental costs is required to accomplish a negative PJM 5CP measurement, it would be reasonable to require the FTM DG customer to pay for those reasonable incremental costs.

V. ESTABLISHING LEGACY RIGHTS UNDER GSC-1

Q. Please describe what you mean by legacy rights.

A. Legacy rights refer to protections that allow customers to continue to take service under the terms of a previous utility rate schedule upon a prospective change to that rate schedule. Such a change could refer to the discontinuance of a rate schedule or rate option within a broader rate schedule, or the establishment of new rules governing the same (e.g., eligibility, a modified rate structure). This practice is also sometimes referred to as grandfathering. From my experience, the central parameters of a legacy rights policy should include: (i) the qualification or eligibility criteria, and (ii) the duration, which can be a defined period of time, or extend into perpetuity (*i.e.*, as long a customer continues to take the applicable service).

Q. What would legacy rights mean in the context of the current proceeding as they pertain to FTM DG customers?

A. In the present context, legacy rights would allow qualifying FTM DG projects to continue to be subject to the current methodology by which PPL classifies customers for default service on either the GSC-1 or GSC-2 rate. In effect, allowing such projects to remain on the GSC-1 default service rider rather than be shifted to the GSC-2 rider. As I will discuss further in this section of my testimony, my proposal for establishing legacy rights establishes three categories of NEM projects, as follows:

1. Operational or under construction projects ("Existing Projects").
2. Mature pre-construction projects ("Transition Projects").
3. Projects that do not qualify as either category (1) or (2) projects ("Non-Legacy Projects").

All Non-Legacy projects would be subject to any revised calculation of MRPL that emerges from this proceeding and, depending on their overall service characteristics, would be placed in the most appropriate classification for default service.

Q. How does your proposal for addressing FTM DG legacy projects and default service classification fall within the scope of this current rate proceeding?

A. The Company placed these issues in this rate proceeding by proposing the MRPL calculation and changes to its GSC rate classifications. A rate proceeding, by its very nature, is a comprehensive review of the Company's rates, services, facilities, as well as the terms and conditions of all its services. The issue of legacy rights pertains to the applicability of the tariff changes PPL is proposing to address and its perceived issues with FTM DG projects. It would be illogical and unreasonable to exclude consideration of the applicability of my proposed changes from the current proceeding in the same way that it would be illogical and unreasonable to do so for proposed changes to the Company's distribution tariff.

A. *Justification and Objectives*

Q. Please briefly explain the justification for establishing a legacy rights policy for FTM DG generators.

A. A NEM system represents a significant investment on the part of the owner. When making such an investment, the owner would, among other things, weigh the potential financial

benefits of that investment against the upfront costs of installing the system. That weighting of costs against future financial benefits inherently involves reliance on the known terms that govern future compensation. When those rules change, as PPL has proposed in this proceeding, the principle of gradualism indicates that due consideration should be given to "rate shock" when evaluating different outcomes. It ultimately comes down to a matter of fairness. To use an analogy, is it fair to change the rules of a game at halftime, or even after it has already been played, in order to engineer a different result?

Q. Are there other considerations present beyond the financial impacts faced by FTM DG project owners?

A. Absolutely. The central issue in this case is the potential escalation of the GSC-1 rate over time due to any increase in the number of FTM DG generators within the class. In Section III of my testimony, I explained how the cost savings benefits of excess generation can and should be realized to eliminate that prospect, and even potentially reduce GSC-1 default service rates. At the same time, the GSC-1 rate class is constrained in its ability to absorb additional FTM DG generation for which those cost savings can be fully realized.[23] Accordingly, it is necessary to prescribe limits on FTM DG legacy rights in order to also protect GSC-1 customers. In other words, the issues of fairness and insulation against rate shock work in both directions and require a careful balance of the respective interests of each group. My proposal reflects this balance.

[23] The small commercial GSC-1 rate class is not large, and the cost savings benefits of load reduction can only be realized against the costs created by the amount of load in the class.

Q. How has this concept of balance been reflected in existing examples of policy and ratemaking?

A. Utility tariffs contain many examples of rate options that are closed to new customers but still allow existing customers to continue service under that rate option. Likewise, legacy rights policies are virtually universal in the context of tariff changes directly aimed at NEM customer-generators. JRB Exhibit-8 contains a list of current NEM legacy rights policies in 22 individual states. This list contains a mix of policies established based on litigated regulatory decisions, adopted settlements, and by statute.

It is also worth noting that this list of examples is limited to states where consideration of legacy rights was actually needed due to changes in NEM policy. In many others, establishing legacy treatment policies was unnecessary because NEM policy had not undergone a meaningful change. For instance, states like Missouri, Colorado, Oregon, Maryland, New Jersey, and Ohio have not established NEM legacy rights policies because they had no need to do so.

Q. Are these examples comparable to the changes PPL is seeking to make to in this proceeding?

A. Yes. The effect of the Company's proposal is to change the compensation rate for NEM generation exported to the grid based on a change in the rate classification of certain NEM customers. These are the same circumstances that gave rise to the examples presented in JRB Exhibit-8. The Company's proposal is indistinguishable on this basis.

Q. Are there unique aspects to the development of FTM DG generators from the standpoint of legacy rights?

A. Yes. Given the relative size of FTM DG system, project developers frequently have extended development timeframes during which they will incur significant pre-installation costs for site control, the cost of interconnection studies, the construction of grid upgrades needed to accommodate the installation, and permitting. Such pre-construction costs can be in the hundreds of thousands of dollars. My proposal reflects this nuance in keeping with the underlying logic of respecting significant investment costs that were incurred based on service terms as they were known and relied upon at the time those investments were made.

One further nuance associated with pre-construction development costs is that under PPL's current interconnection process, interconnection customers are obligated to pay a non-refundable cash deposit of 25% of estimated upgrade costs upon signing a Notice of Customer Intent ("NoCI").[24] My understanding is that the purpose of this requirement is to ensure that the Company is adequately compensated for the various costs that it incurs when engineering and planning distribution upgrades, even if the project ultimately fails to commence operation. However, it is also my understanding that the 25% deposit requirement did not exist for interconnection applications submitted prior to 2024. As a result, some interconnection customers with planned projects have made such as deposit whereas others have not done so, although they would remain responsible for the Company's actual costs of planning an upgrade even if the project is cancelled. My legacy

[24] PPL Electric. Net Metered Distributed Energy. Available at: https://www.pplelectric.com/site/More/For-Construction/Building-or-renovating/Net-Metered-Distributed-Energy. The deposit is due within 45 calendar days.

rights proposal for non-operational projects reflects this reality, as I describe further in Section V(B) of my testimony.

B. *Proposal for Establishing Legacy Rights*

Q. Please summarize the objectives of your legacy rights proposal.

A. I approached legacy rights from two perspectives: (i) GSC-1 customers, and (ii) FTM DG project owners, with equal weight given to the interests of both parties. This balance is reflected in my three objectives:

1. Provide reasonable protections in an equitable manner to both GSC-1 customers and FTM DG project owners.
2. Minimize future risks and uncertainties.
3. Ensure that the applicable legacy rights qualification milestones and thresholds are clear and practicable so as to limit the potential for future disputes and significant administration work by PPL.

Q. Please outline the components of your legacy rights proposal.

A. I recommend that the legacy rights policy be designed as follows, again, with the specific project owner "right" being the treatment under the present methodology for the purpose of default service rate classification (*i.e.*, remain classified as GSC-1 customers).

Existing FTM DG Facilities ("Existing Facilities"):

- *Qualification Standard*: Facilities that were either operational or for which interconnection upgrade work orders are under construction as of the date of PPL's rate filing in this proceeding.
- *Legacy Treatment*: Full legacy rights without further condition for the operational life of the project.

Transition Facilities:

- *Qualification Standard*: FTM DG facilities with pending interconnection requests submitted prior to the date of PPL's rate application in this proceeding, for which the FTM DG customer makes a one-time election to both: (i) make a non-refundable deposit of 50% of the Company's estimated costs of distribution upgrades (cumulative), and (ii) transfer AECs produced by the project to PPL at no cost for the term of the legacy rights period. Such "cumulative" amounts would include any non-refundable payments that have already been made.
- *Legacy Treatment*: Legacy rights for the operational life of the project conditioned on continued compliance with the AEC transfer requirement for the duration of the legacy rights period.

To be clear, any potential Transition Facility for which the owner elects to retain AEC ownership or declines to pay the 50% enhanced distribution upgrade deposit would be a Non-Legacy Facility.

Q. Please elaborate on the rationale underlying your legacy rights proposal for Existing Facilities.

A. The owners of Existing Facilities have already made complete or nearly complete investments measured in millions of dollars, including meeting all of their financial obligations for grid upgrades necessary to accommodate the project and fulfilling conditions associated with land use permitting. Given the typical timelines for projects of this size, those investments would have been made long before it could have been reasonably known that the NEM regime supporting the project was at risk of being significantly changed. Those customer-generator investments deserve protection as a

matter of basic fairness, a principle that has been well-recognized in numerous state jurisdictions. In fact, I am only aware one instance where a major change in NEM structure was applied to existing NEM installations (i.e., Nevada). In that case, regulators reversed course several months later and rescinded the applicability of a revised NEM structure to existing facilities, granting such facilities a legacy rights period of 20 years.[25]

Q. How large is the volume of FTM DG projects that would qualify as Existing Facilities?

A. While we have not received detailed information from PPL on this issue, anecdotal information seems to suggest the volume is fairly small. Information provided by PPL indicates that there are currently only 6 operational FTM DG projects in its service territory larger than 2 MW, totaling 15.675 MW.[26] Information on the Company's interconnection queue shows only 2 additional projects (4.25 MW) that might represent FTM DG facilities with an under construction work order status. Those projects date from interconnection applications submitted in 2022 and 2023.[27] Thus, the interconnection applications were submitted well before the Commission first considered the matter of FTM DG default service classification in the UGI Utilities' default service proceeding at Docket No. P-2024-3049343 et al. ("UGI Proceeding"). Given this small number of projects in relation to the size of the GSC-1 customer base and the relatively small gap between excess generation value excluding AEC value and the PTC that I discussed in Section III of my testimony, the size of the GSC-1 class is sufficient to absorb these projects with minimal impacts.

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[25] *Application of Nevada Power Company; Application of Sierra Pacific Power Company*, Docket Nos. 16-07028, 16-07029, 2016 WL 5475729, September 21, 2016.

[26] JRB Exhibit - 9, JSA I-23 Attachment 1.

[27] Company response to JSA I-2, Confidential Attachment 2. This assessment excludes projects that are reflected with a work order status of under construction but also are identified as installed and in service in PPL's interconnection data.

Q. Is the establishment of legacy rights for Existing Facilities consistent with your understanding of the Commission's determination in the UGI Proceeding and related default service plan?

A. Yes. I believe it to be. In Vice Chair Barrow's concurring statement in the UGI Proceeding, she noted relevant to this question "Moreover, the change proposed by UGI does not impact any existing net metering customers."[28] Although I do not see any similar references in the Recommended Decision or the Commission's Final Order in the UGI Proceeding, I take this to indicate that lack of impact on existing facilities was part of the Commission's, or at least Vice Chair Barrow's, weighing of the various issues when reaching a determination.

Q. Please further explain the rationale for conditioning legacy rights for Transition Facilities on the payment of a 50% deposit against estimated distribution upgrade costs.

A. The underlying rationale for legacy rights is protecting investments made prior to the time when rule changes that would undermine those investments could have been appreciated as risks and factored into investment decisions. Those investments include costs associated with general planning, permitting, and the funding of distribution upgrades that may be needed to accommodate a given project. The objective is to protect the most "mature" projects for which those sunk costs are the highest.

PPL's 2024 change in interconnection upgrade payment protocols presents a challenge for devising a clear and practicable project maturity metric based on costs already incurred by FTM DG customers. Therefore, some of the Transition Facilities have paid

[28] *Petition of UGI Utilities, Inc – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2025 through May 31, 2029*, Nos. P-2024-3049343, G-2024-3049351, and C-2024-3049618 (February 20, 2025).

the 25% non-refundable deposit and others (i.e., the older vintage projects) have not. And all projects, regardless of whether they have paid the 25% non-refundable deposit or not, remain obligated to compensate PPL for all of its costs incurred.

The one-time election to avail themselves of legacy rights by virtue of making an enhanced 50% deposit against distribution upgrade costs addresses this challenge by placing the project maturity determination in the hands of those that are best-suited to make such an evaluation: the interconnection customer/project owner. The 50% deposit would represent a significant investment that effectively confirms a high level of commitment in a given project irrespective of where that project falls within the timeline of changes to PPL's upgrade deposit policy. Since it is assessed as a cumulative percentage that includes the costs that some project owners have already paid, it fully levels the playing field with respect to a project owner's level of commitment. Finally, it establishes an easy-to-implement bright-line test that will create certainty as to the maximum volume of Transition Facilities that could qualify for legacy rights.

Q. Are there any other issues associated with implementing the interconnection deposit aspect of your legacy rights proposal for Transition Facilities?

A. Yes. The first question is how the election option would function. I recommend that PPL issue a notice to each potential Transition Facility upon Commission approval of its compliance tariff in this case requesting the customer's election. Consistent with PPL's present interconnection upgrade deposit policy, a payment from the customer should be due within 45 days of that notice. This election process should be combined with the second condition of the proposal regarding a commitment to provide AECs produced by the facility to PPL at zero cost.

Second, I appreciate that my proposal would not allow the Commission or PPL to know the full volume of Transition Facilities that may qualify for legacy rights in advance, prior to the election process. To address any potential concern about this issue, the PaPUC could establish a maximum volume of project MWs in its final order in this case. If the Commission elects to establish such a cap and customer elections exceed it, qualification for legacy rights should be determined by the date that a customer executed the NoCI. Any facility that gets excluded on this basis of such a cap should be permitted a refund of the incremental amount of their deposit in relation to any non-refundable amounts that they previously paid. To be clear, a refund would only be due to an interconnection customer if they are not allotted a cap allocation due to over-subscription. Otherwise, the enhanced deposit would be non-refundable, like the present 25% deposit policy.

Q. Please further explain the rationale underlying your proposal that legacy rights for Transition Facilities be conditioned on the surrender of AECs to PPL at no cost.

A. The conveyance of AECs from Transition Facilities that elect to do so is intended to bridge the "value gap" between the GSC-1 excess generation cash-out rate and the cost reductions that excess generation produces for default service (inclusive of transmission) as I outlined in Section III of my testimony. These transferred AECs would effectively represent long-term contracted AECs, the benefits of which can be realized through substitution of AECs that PPL would have otherwise been required to purchase, or through AEC sales that produce additional revenue. Those benefits can then be applied to reduce the AEPS Act compliance cost component of the GSC-1 rate. Again, my excess generation value calculations indicate that with the added value of AECs, the total value rate would be

slightly above the PTC cash-out rate, eliminating any upward pressure on the small commercial GSC-1 rate.

Q. Is your AEC conveyance consistent with your understanding of Pennsylvania law?

A. Yes. I have been advised by counsel that Pennsylvania's NEM rules expressly addresses circumstances where a NEM customer rejects ownership of AECs produced by a NEM facility, allowing a utility to take title to those AECs.[29] PPL's GSC-1 tariff also includes a clause providing for the GSC-1 charge to be reduced by revenue received from the sale of AECs.[30]

Q. Are there any further steps associated with realizing the value of zero-cost AECs for the benefit of GSC-1 small commercial customers?

A. Yes, but they are not difficult to put in place. If the AECs are sold, the resulting revenue would need to be applied exclusively for the benefit of the small commercial GSC-1 customer class. This would be accomplished by a simple assignment or accounting measure on PPL's part. The process would be a little more involved if AECs are not sold but instead reduce PPL's AEC procurement volume because it is my understanding that PPL does not procure AECs for its small commercial default supply contracts. Rather, it is the wholesale supplier's obligation to procure the requisite AECs needed for AEPS Act compliance.[31]

In this scenario, the FTM DG AECs would substitute for the procurement of AECs to serve the ten-year long-term block of PPL's residential default service supply, akin to PPL purchasing AECs from FTM DG customers to serve the long-term residential block.

[29] 52 Pa. Code 75.14(d).
[30] PPL Electric Tariff. Eighteenth Revised Page No. 19Z.4.
[31] JRB Exhibit-10, JSA IV-2(c).

However, it would be necessary to establish a proxy AEC price for this transaction since in reality the AECs were conveyed to PPL at a nominal zero cost. The reduction in the small commercial GSC-1 revenue need would mimic a sale, with the revenue calculated as the FTM DG AEC volume multiplied by the proxy price. In other words, residential customers would pay for these AECs, the same as they would if PPL secured them through an RFP, and the resulting revenue would benefit the small commercial GSC-1 rate class.

Q. How would the proxy AEC price be determined?

A. It is my understanding that the Commission already evaluates AEC market prices as part of their review of the Company's annual AEC Requests for Proposals ("AEC RFPs").[32] The Commission could determine the appropriate proxy AEC price based on the same type of review, as it would have when assessing the reasonableness of the results of the annual AEC RFP.

Q. Are there any additional benefits beyond those you have already discussed associated with extending legacy rights to Transition Facilities in exchange for AECs?

A. Yes. There are at least two. First, the conveyance of AECs would create a long-term hedge against future increases in AEC prices, primarily Tier 1 AECs. Pennsylvania's most recent AEPS Report indicates that Tier 1 AEC prices have risen dramatically in recent years, from $6.31/MWh in 2019 to $31.01/MWh in 2024.[33] Those Tier 1 AEC prices are driven primarily by factors outside of the Commission's control, such as the escalation of Tier 1 targets in other states accompanied by long interconnection timelines for new Tier 1 resources. The amounts are higher than the AEC price estimate ($26.42/MWh) I used in

[32] JRB Exhibit -11, JSA IV-2(b).

[33] PA PUC. Alternative Energy Portfolio Standards Act of 2004, Compliance for Reporting Year 2023-2024. June 2025. Chart 7 at p. 18.

Section III, which was based on the results of PPL's July 2025 AEC solicitation. But they illustrate that there is a potential risk associated with future prices. There is value in insulating against this future price risk via the legacy rights arrangement (i.e., effectively 20-year contracts) that I propose, which is financially justified even based on the lower price point I used.

Second, notwithstanding any other factors and considerations, like any construction project, local Pennsylvania FTM DG projects contribute to economic activity within Pennsylvania, producing jobs-related benefits for local construction and other tradespeople and accompanying indirect benefits (*i.e.*, spending at local businesses). Planned projects that are ultimately cancelled due to PPL's default service rate classification proposal will not provide these benefits. In this regard, it is also worth noting that there is a tether between alternative energy systems located in Pennsylvania and the AEPS Act. During 2024 only 34% of the Tier 1 AECs retired to meet the AEPS Act targets were produced by generation facilities located in Pennsylvania.[34] So, in large part, Pennsylvania ratepayers primarily paid AEPS Act costs that supported economic development outside of the state. My Transition Facilities legacy rights design provides an avenue to realize the economic activity benefits as an offset to ratepayer costs and, moreover, concentrate them within PPL's service territory among the same customers that pay PPL's AEPS Act costs.

VI. CONCLUSION

Q. Please summarize your recommendations.

A. I recommend that the Commission adopt my proposed approach for addressing issues associated with FTM DG customers, which consists of the following elements:

[34] PA PUC. Alternative Energy Portfolio Standards Act of 2004, Compliance for Reporting Year 2023-2024. June 2025. Chart 1 at p. 8.

- The Commission should direct PPL to modify how it determines customer peak loads for the purposes of generation capacity and transmission cost allocation to: (i) allow those values to reflect "negative loads" produced by FTM DG customers, and (ii) apply the cost savings benefits of those negative loads to reduce the allocation of the relevant costs to the rate class in which the FTM DG customer resides.
- The Commission should direct the Company to improve alignment of the GSC-2 rate with cost causation by allowing customers to register "negative peak loads", and revise the PTC-based compensation for excess NEM generation to include a credit for any FTM DG customer with a negative peak load value.
- The Commission should adopt my proposal for establishing legacy rights under the GSC-1 rate for all FTM DG projects that are operational or under construction as of the date of PPL's rate filing application.
- The Commission should adopt my proposal for establishing legacy rights under the GSC-1 rate for a subset of planned but not operational FTM DG projects that meet certain maturity and financial commitment milestones, conditioned on the FTM DG project owner also agreeing to surrender AECs produced by the project to PPL at no cost for the duration of the legacy rights term.

Q. Does this conclude your testimony?

A. Yes. However, I reserve the right to submit such additional testimony as may be necessary or appropriate.

APPENDIX A – GLOSSARY OF TERMS

AC – Alternating Current

AEC(s) – Alternative Energy Credit(s)

AEPS Act - Alternative Energy Portfolio Standards Act

BTM – Behind The Meter

BTM DG – Behind The Meter Distributed Generation

CCSA – Coalition for Community Access

CIAC – Contributions in Aid of Construction

COSS – Cost of Service Study

CP – Coincident Peak

DG – Distributed Generation

DRIPE - Wholesale Market Price Effect

DSIRE - Database of State Incentives for Renewables and Efficiency

DSP – Default Service Provider

EDC - Electric Distribution Company

EGS – Electric Generation Supplier

FERC – Federal Energy Regulatory Commission

Feeder – an electric line of distribution level voltage

FTM DG – Front of The Meter Distributed Generation

GSC – Generation Service Charge

GSC-1 – the charge applied to residential and selected small commercial/industrial customers who take default service

GSC-2 – the charge applied to customers in the large industrial class who take default service from PPL under rate schedules GS-3, LM-4, LP-5

ICAP – Installed Capacity

IEEE- Institute of Electrical and Electronics Engineers

IRPs – Integrated Resource Plans

JSA – Joint Solar Advocates

kW - kilowatt

LMP – Locational Marginal Price

MRPL – Maximum Registered Peak Load

MW – megawatt

NCP – Non-coincident peak

NEM – Net Energy Metering/Metered

NOAA - National Oceanic and Atmospheric Administration

NoCI – Notice of Customer Intent

NREL – National Renewable Energy Laboratory

NREL SAM - National Renewable Energy Laboratory's System Advisor Model

OATT – Open Access Transmission Tariff

PaPUC – Pennsylvania Public Utility Commission

PPL – PPL Electric Utilities Corporation

PLC – Peak Load Contribution

PTC – Price To Compare

PV- Photovoltaic

RPM – Reliability Pricing Model (PJM)

SCI – Small Commercial and Industrial

SEIA – Solar Energy Industries Association

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission Coalition For Affordable Utility Services And Energy Efficiency in Pennsylvania Office of Small Business Advocate Brad and Jennifer Woolley	Docket Nos. R-2025-3057164 C-2025-3057844 C-2025-3057889 C-2025-3057946
v.	
PPL Electric Utilities Corporation	

VERIFICATION

I, Justin R. Barnes, hereby declare that I am the President of EQ Research LLC; that, as such, I am authorized to make this verification on their behalf; that the facts set forth in the foregoing Direct Testimony are true and correct to the best of my knowledge, information and belief, and that I make this verification subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Date: December 22, 2025

By: _____
Justin R. Barnes, President
EQ Research LLC

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2025-3057164
v.	:	
	:	
PPL Electric Utilities Corporation	:	
	:	

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JRB
EXHIBIT-1

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University of Oklahoma Norman, Oklahoma
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President, May 2023 – present
Director of Research, July 2015 – April 2023
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC Cary, North Carolina

- Oversee state legislative, regulatory policy, utility IRP and general rate case tracking services that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service and cost allocation, general rate design, low-income issues. DER value, and DER policy including incentive program design, community solar program design, and DER-specific rate design issues.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future.* 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments.* July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts.* December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues.* July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri.* 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On.* 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar.* 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends.* Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets.* 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar.* 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues.* 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY & OTHER REGULATORY ASSISTANCE

Kentucky Public Service Commission. Docket No. 2025-00257. November 2025. On behalf of the Kentucky Solar Industries Association. Kentucky Power general rate case. Addressed proposed changes to Kentucky Power's COGEN/SPP tariffs governing the terms of service for PURPA QFs focused on aspects relating to new proposed language regarding the establishment of a PURPA legally enforceable obligation and the existence of discriminatory charges placed on QF customers.

Indiana Utility Regulatory Commission. Cause No. 46258. September 2025. On behalf of the Citizen's Action Coalition of Indiana. AES Indiana generation rate case application. Addressed: (a) the proper calculation of a residential customer charge based on customer-related costs, (b) the Company's evaluation of cost of services differences between multi-family and non-multi-family customers and the justification for a lower customer charge for multi-family customers, and (c) the reasonableness of the Company's declining block rate design from a cost of service standpoint, with a particular focus on customers that rely on electric heating. Developed a consolidated residential rate design proposal encompassing these collective issues.

West Virginia Public Service Commission. Case No. 24-0854-E-42T. April 2025. On behalf of the West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia. Appalachian Power Company and Wheeling Power Company general rate case. Addressed issues that included the utilities' proposed elimination of net metering and related issues of subsidization, calculation of the value of DER exports, the Companies' collective ratemaking and cost tracker proposals, the need for enhanced low-income financial support mechanisms and other means of reducing energy burdens on low-income customers, the cost basis for reconnection charges, demand limits within the small commercial rate schedules, deficiencies in the Companies' residential TOU rate, and the cost basis of the Companies' LED lighting rate proposals.

New Mexico Public Regulation Commission. Case No. 24-00089-UT. January 2025. On behalf of the Coalition for Community Solar Access. Public Service Company of New Mexico. Testimony in support of a Stipulation regarding the appropriate functionalization of rate impact banding adjustments as related to the calculation of the community solar subscriber credit.

Michigan Public Service Commission. Case No. U-21534. July 2024. On behalf of the Michigan Energy Innovation Business Council and The Institute for Energy Innovation. DTE Electric Company general rate case application. Sponsored testimony recommending revisions to the utility's proposed time-varying rate options for non-residential customers addressing issues including revenue-neutral rate schedule mapping, appropriate pricing windows, enrollment caps, implementation timeline, and customer outreach and tools.

Indiana Utility Regulatory Commission. Cause No. 45990. March 2024. On behalf of the Citizen's Action Coalition of Indiana. Centerpoint Indiana South generation rate case application. Addressed: (a) numerous cost of service and cost allocation issues associated with production plant, transmission plant, coal ash disposal, MISO expenses, and service advertisement expenses; (b) cost-shifting caused by special contract customers and customers served under an industrial back-up service rate; and (c) the proper calculation of a residential customer charge based on customer-related costs.

West Virginia Public Service Commission. Case No. 23-0460-E-42T. November 2023. On behalf of the West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia. Monongahela Power and Potomac Edison general rate case application. Addressed issues that included the utilities' proposed elimination of net metering and related issues of subsidization, the methodology for setting monthly customer charges, demand limits within the small commercial rate schedules, piloting non-residential TOU rates, distribution cost allocation, the utilities' proposed distribution infrastructure investment program and long-term distribution planning, and support mechanisms for reducing energy burdens on low-income customers.

New Mexico Public Regulation Commission. Case No. 23-00071-UT. November 2023. On behalf of the Coalition for Community Solar Access. New Mexico community solar tariffs implementation proceeding. Addressed the methodology for quantifying any subsidy provided to community solar participants, the calculation of the community solar subsidy cap associated with the New Mexico's community solar law, the utilities' proposed administrative cost riders, and the utilities' proposed community solar eligibility restrictions.

Michigan Public Service Commission. Case No. U-21297. June 2023. On behalf of the Michigan Energy Innovation Business Council and The Institute for Energy Innovation. DTE Electric Company general rate case application. Sponsored a proposal for the establishment of time-varying rate options for non-residential customers.

North Carolina Utilities Commission. Docket Nos. E-34 Sub 54 and Sub 55. June 2023. On behalf of Appalachian Voices. New River Light and Power general rate case application. Analyzed the utility's proposal to establish NEM with a supplemental standby charge based on an evaluation of customer-sited solar costs and benefits and the utility's proposal for an increase in the residential fixed charge. Recommended the elimination of the DG standby charge based on corrections to NRLP's solar value analysis and a decrease in the residential fixed charge based on revised calculations of customer-related costs.

Georgia Public Service Commission. Docket No. 44280. Direct Testimony in October 2022 and Supplemental Testimony in November 2022. On behalf of Georgia Interfaith Power and Light. Georgia Power Company general rate case application. In Direct Testimony, provided a review and analysis of the cost allocation regime for coal combustion residual costs and provided recommended changes thereto; and evaluated the Company's proposals designed to shift residential customers to service under demand rate designs, including general analysis of the cost causation basis for demand rates and specific attributes and Company experience with its residential demand rate. In Supplemental Testimony, evaluated the Company's proposal to end its monthly netting DG tariff (i.e., NEM) and require mandatory demand rate service for future DG customers and recommended that NEM be retained without a mandatory demand rate requirement based on analysis demonstrating that doing so would not adversely affect non-DG customers.

Wisconsin Public Service Commission. Docket No. 5-UR-110. September 2022. On behalf of RENEW Wisconsin. Wisconsin Electric Power Company general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

Wisconsin Public Service Commission. Docket No. 6690-UR-127. September 2022. On behalf of RENEW Wisconsin. Wisconsin Public Service Corporation general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

Wisconsin Public Service Commission. 3270-UR-124. September 2022. On behalf of RENEW Wisconsin. Madison Gas and Electric general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit. (*Note: Exhibit was introduced at the hearing and testimony on the methodology provided orally at the hearing; written testimony was not filed).*

Michigan Public Service Commission. Case No. U-20836. May 2022. On behalf of the Michigan Energy Innovation Business Council and The Institute for Energy Innovation. DTE Electric Company general rate case application. Addressed the utility's proposal for changes to its DG Tariff, including excluding generation capacity value from the export rate and requiring DG customers to take service under a newly proposed residential demand rate. Also evaluated the cost causation and other rate attributes of the proposed residential demand rate.

Virginia State Corporation Commission. Docket No. PUR-2021-00171. January 2022. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Evaluation of the cost basis for the residential customer charge, AMI deployment and the timeline for deployment of TOU rates, class allocation of distribution and production demand costs, and the Company's proposal for a DSM/EE pilot program and cost recovery rider.

Michigan Public Service Commission. Case No. U-20963. June 2021. On behalf of the Michigan Energy Innovation Business Council and the Institute for Energy Innovation. Consumers Energy Company general rate case. Provided an evaluation of the utility's proposed home battery program and

offered recommendations for modifications to the program to improve its cost-effectiveness and delivery of benefits to participants and non-participants through changes to battery operational plans, elimination of restrictions on consumer use of the batteries, battery sizing modifications to fit actual customer needs, and use of solar-paired storage to provide greater resiliency.

Colorado Public Utilities Commission. Proceeding No. 20AL-0432E. March 2021. On behalf of the Colorado Solar and Storage Association and the Solar Energy Industries Association. Public Service Company of Colorado (Xcel Energy Colorado) general rate case. Provided analysis and recommendations on several non-residential rate design issues, including the utility's practice of switching small commercial customers to demand rates, relaxing the demand threshold at which commercial customers are subject to demand rates, the utility's proposal for modifying time-varying pricing windows, and the establishment of a pilot time-of-use rate for Secondary General (SG) commercial customers intended to remedy the misalignment between the SG non-coincident demand rate design and cost causation and set a foundation for a default time-varying rate option for SG class customers.

Kentucky Public Service Commission. Docket Nos. 2020-00349 and 2020-00350. March 2021 (Phase 1) and July/August 2021 (Phase 2). On behalf of the Kentucky Solar Energy Industries Association. Kentucky Utilities and Louisville Gas and Electric general rate case applications. Provided an analysis of the utilities' current tariffs governing purchases from qualifying facilities and recommended changes to align them with state regulations, recent precedent, and accepted methodologies of energy and capacity pricing.

South Carolina Public Service Commission. Docket Nos. 2020-264-E and 2020-265-E. February 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Duke Energy Carolinas and Duke Energy Progress. Provided testimony in support of a stipulated settlement discussing the critical role that a proposed smart thermostat rebate and enabling technologies more generally play in the successfully meeting the legislative objectives for Solar Choice tariffs.

South Carolina Public Service Commission. Docket No. 2020-229-E. January 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Dominion Energy South Carolina. Provided an analysis of the proposed Solar Choice tariff from the standpoint of NEM successor best practices, alignment with the enabling statute, and cost of service basis. Offered an alternative Solar Choice tariff proposal based on this analysis. Surrebuttal testimony provided an evaluation of solar customer cost of service correcting erroneous assumptions used by the Office of Regulatory Staff in its direct testimony.

Virginia State Corporation Commission. Docket No. PUR-2020-00134. January 2021. On behalf of the Behind the Meter Solar Alliance. Docket for Dominion Virginia's 2020 RPS Plan. Offered testimony supporting the designation of small-scale resource carve-out eligibility being limited to behind the meter resources, based on the underlying Virginia statute and other public policy reasons.

South Carolina Public Service Commission. Docket No. 2019-182-E. October 2020. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a cost-benefit analysis methodology and protocols for net metering and DERs. Provided discussion of historic regulatory use of DG cost-benefit and cost of service studies, how results should be viewed, and a discussion of the role of economic benefits and resiliency in DER cost-benefit analyses.

Kentucky Public Service Commission. Docket No. 2020-00174. October 2020. On behalf of the Kentucky Solar Industries Association. Kentucky Power general rate case. Provided an evaluation and critique of the cost of service support for, and design of, Kentucky Power's proposed net metering

successor tariff and offered recommendations for developing cost-based DER rate designs. Also recommended changes to the utility's QF tariff and calculation of capacity costs.

New Jersey Board of Public Utilities. Docket No. EO18101111. September 2020. On behalf of Sunrun, Inc. Public Service Gas and Electric energy storage deployment plan proposal. Offered alternative proposal for a program utilizing non-utility owned energy storage assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

Virginia State Corporation Commission. Docket No. PUR-2020-00015. July 2020. On behalf of Appalachian Voices. Appalachian Power Company general rate case. Analysis of the cost basis for the residential customer charge, the Company's winter declining block rate proposal, and a proposed Coal Asset Retirement Rider (Rider CAR) providing for advance collection of anticipated accelerated depreciation of coal generation assets. Provided an alternative residential customer charge recommendation and an alternative rates proposal for addressing winter bill volatility for electric heating customers.

North Carolina Utilities Commission. Docket No. E-2 Sub 1219. April 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

North Carolina Utilities Commission. Docket No. E-7 Sub 1214. January 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

Virginia State Corporation Commission. Docket No. PUR-2019-00060. November 2019. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Analysis of the cost basis for the residential customer charge, proposal to change the residential customer charge from a monthly charge to a daily charge, and design of proposed customer green power program and utility owned commercial behind the meter solar proposal. Proposed modified optional rate structure for mid- to large-size non-residential customers with on-site solar and/or low load factors.

Georgia Public Service Commission. Docket No. 42516. October 2019. On behalf of Georgia Interfaith Power and Light, Southface Energy Institute, and Vote Solar. Georgia Power Company general rate case application. Analysis of the cost basis for the residential customer charge, the validity of the utility's minimum-intercept study, and a proposal to change the residential customer charge from a monthly charge to a daily charge.

Hawaii Public Utilities Commission. Docket No. 2018-0368. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

Virginia State Corporation Commission. Docket No. PUR-2019-00067. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

New York Public Service Commission. Case No. 19-E-0065. May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

South Carolina Public Service Commission. Docket No. 2018-318-E. March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

South Carolina Public Service Commission. Docket No. 2018-319-E. February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

New Orleans City Council. Docket No. UD-18-07. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500274. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Masters Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

JRB
EXHIBIT-2

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-19	If PPL does not utilize excess electricity it purchases from customer-generators as part of its default service supply, please explain in detail what PPL does with this supply? Provide all Documents that support, are utilized and/or relied upon in your answer.
PPL Electric Response	PPL Electric does not purchase excess electricity from customer-generators. Rather, the Company provides bill credits and monetary payouts for the excess generation at the end of the PJM planning year in accordance with applicable statutes and regulations. The customer-generator's excess generation reduces the aggregate load, thereby lowering the procurement for the Company's load-following contracts in its default service procurement.

JRB
EXHIBIT-3

PPL Electric Utilities Corporation
Response to the Set IV Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 26, 2025
Docket No. R-2025-3057164

JSA IV-3

Refer to Exhibit GEO-1 at p. 69 showing the Company's proposed GSC-2 tariff.

a. Please describe how a customer's "fixed peak load capacity obligation" is determined by the Company.
b. Can a customer's fixed peak load capacity obligation be a negative amount?
c. If a customer cannot have a negative fixed peak load capacity obligation, please provide a citation to the specific language in the "applicable PJM agreements" that does not permit a customer to have a negative fixed peak load capacity obligation.
d. If a customer is permitted to have a negative fixed peak load capacity obligation, would the GSC-2 capacity charge be reflected as a credit on a GSC-2 customer's default service bill? Please explain in detail.
e. Provide all Documents used, relied upon and/or that support each answer in subparts (a)-(d) above.

PPL Electric Response

a. The Company calculates customer ICAP PLC values by averaging each individual customer's interval usage data during each of the five PJM Zone peaks from the prior year, as identified by PJM. Each customer's PLC value is then adjusted based on loss allocation and reconciliation factors.
b. A customer's fixed peak load capacity obligation cannot be negative.
c. The PJM OATT, Attachment M-2 (PPL Electric Utilities Corp.), found at https://agreements.pjm.com/oatt/39999, titled "Determination of Capacity Peak Load Contributions, Network Service Peak Load and Hourly Load Obligations" ("PPL Electric M-2"), does not allow for a negative peak load capacity.

d. A customer is not permitted to have a negative fixed peak load capacity obligation.
e. The Company relied in part on the PPL Electric M-2.

JRB
EXHIBIT-4

PPL Electric Utilities Corporation
Response to the Set IV Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 26, 2025
Docket No. R-2025-3057164

JSA IV-3

Refer to Exhibit GEO-1 at p. 69 showing the Company's proposed GSC-2 tariff.

a. Please describe how a customer's "fixed peak load capacity obligation" is determined by the Company.
b. Can a customer's fixed peak load capacity obligation be a negative amount?
c. If a customer cannot have a negative fixed peak load capacity obligation, please provide a citation to the specific language in the "applicable PJM agreements" that does not permit a customer to have a negative fixed peak load capacity obligation.
d. If a customer is permitted to have a negative fixed peak load capacity obligation, would the GSC-2 capacity charge be reflected as a credit on a GSC-2 customer's default service bill? Please explain in detail.
e. Provide all Documents used, relied upon and/or that support each answer in subparts (a)-(d) above.

PPL Electric Response

a. The Company calculates customer ICAP PLC values by averaging each individual customer's interval usage data during each of the five PJM Zone peaks from the prior year, as identified by PJM. Each customer's PLC value is then adjusted based on loss allocation and reconciliation factors.
b. A customer's fixed peak load capacity obligation cannot be negative.
c. The PJM OATT, Attachment M-2 (PPL Electric Utilities Corp.), found at https://agreements.pjm.com/oatt/39999, titled "Determination of Capacity Peak Load Contributions, Network Service Peak Load and Hourly Load Obligations" ("PPL Electric M-2"), does not allow for a negative peak load capacity.

d. A customer is not permitted to have a negative fixed peak load capacity obligation.
e. The Company relied in part on the PPL Electric M-2.

JRB
EXHIBIT-5

ATTACHMENT M-2 (ComEd)

Determination of Capacity Peak Load Contributions, Network Service Peak Load Contributions, Daily Peak Load Obligation , Daily Network Service Peak Load Obligation, and Hourly Load Obligations

I. CAPACITY AND NETWORK SERVICE PEAK LOAD CONTRIBUTIONS

Section 1 PURPOSE

The purpose of Part I. is to describe the methodology used to determine capacity and network service peak load contributions for electric power and energy attributable to customers located in the ComEd Zone.

Section 2 DEFINITIONS

The following definitions are for use in this Attachment M-2. Capitalized terms used and not defined in this Attachment M-2 but defined in other provisions of the PJM OATT have the meaning given them under those provisions. Capitalized terms used in this Attachment M-2 that are not defined in it or elsewhere in the PJM OATT have the meanings customarily attributed to such terms by the electric utility industry in PJM.

a) **Average ComEd Coincident Peak Load:** the average of the sum of the (i) five (5) ComEd Zonal Loads established during the PJM Five Peaks in a summer and (ii) the corresponding Load Drop Estimates for such PJM Five Peaks.

b) **Average ComEd Peak Load:** the average of the five (5) ComEd Zonal Loads established during the ComEd Five Peaks in a summer.

c) **Average Customer Coincident Peak Load:** the average of the sum of the (i) five (5) customer loads established during the PJM Five Peaks in a summer and (ii) the corresponding Load Drop Estimates for such customer, with such sum adjusted to include applicable distribution and transmission system losses.

d) **Average Customer Peak Load:** the average of the five (5) loads established by the customer during the ComEd Five Peaks in a summer, with such loads adjusted to include applicable distribution and transmission system losses.

e) **ComEd Five Peaks:** the five hours occurring on different calendar days in a summer during which the electric system served by ComEd experiences its five highest daily summer demands.

f) **ComEd Weather Normalized Peak Load:** the expected ComEd Zonal Load at the time of the PJM system peak load in a summer under normal weather conditions as determined by PJM.

g) **ComEd Peak Load:** the highest ComEd Zonal Load established for PJM network service in a summer.

h) **ComEd Zonal Load:** the demand for electricity placed upon the interconnected electricity system operated by PJM that is attributable to customers located in the ComEd Zone.

i) **Load Drop Estimate:** the kilowatt (kW) value attributable to curtailed demand as determined by PJM.

j) **PJM Five Peaks:** the five hours occurring on different calendar days in a summer during which the electric system served by PJM experiences its five highest daily summer demands.

k) **Summer:** the period beginning June 1 and extending through September 30 in a calendar year.

Section 3 DETERMINATION OF THE CAPACITY PEAK LOAD CONTRIBUTION

If a customer's Average Customer Coincident Peak Load for Year Y is greater than or equal to such customer's Average Customer Peak Load for Year Y, then such customer's capacity peak load contribution (CPLC) for year Y+1 is equal to such customer's Average Customer Coincident Peak Load for Year Y.

If a customer's Average Customer Coincident Peak Load for Year Y is less than such customer's Average Customer Peak Load for Year Y, then such customer's CPLC for year Y+1 is determined in accordance with the following equation:

$$CPLC_{Y+1} = ACustCPL_Y + \left(ComEdNPL_Y - AComEdCPL_Y\right) \times \frac{ACustPL_Y - ACustCPL_Y}{\sum_{5Pc}\left(ACustPL_Y - ACustCPL_Y\right)}$$

Where:

$CPLC_{Y+1}$ = Capacity Peak Load Contribution for the customer, in kW, applicable for the period beginning with June in Year Y+1 and extending through May in Year Y+2.

$ACustCPL_Y$ = Average Customer Coincident Peak Load for the customer for Year Y, in kW.

$ACustPL_Y$ = Average Customer Peak Load for the customer for Year Y, in kW.

$ComEdNPL_Y$ = ComEd Weather Normalized Peak Load for Year Y, in kW.

$AComEdCPL_Y$ = Average ComEd Coincident Peak Load for Year Y, in kW.

$\sum_{5Pc}$ = Summation over all customers for which the Average Customer

Coincident Peak Load for Year Y is less than the Average Customer Peak Load for Year Y.

Notwithstanding the previous provisions describing the determination of the $CPLC_{Y+1}$, for certain situations ComEd determines a customer's $CPLC_{Y+1}$ to be equal to (i) the average $CPLC_{Y+1}$ attributable to the delivery class applicable to such customer or (ii) the average $CPLC_{Y+1}$ attributable to the delivery class applicable to such customer scaled to reflect the amount of electricity delivered to such customer. Delivery classes are as described in the General Terms and Conditions of ComEd's Schedule of Rates filed with the Illinois Commerce Commission (Ill. C.C. No. 10). For purposes of this Attachment M-2 (ComEd), load attributable to net metering and community supply projects may reflect both consumption and generation in the CPLC, and therefore can result in a positive or negative value for any such individual customer's calculation.

Section 4 DETERMINATION OF THE NETWORK SERVICE PEAK LOAD CONTRIBUTION

A customer's Network Service Peak Load Contribution (NSPLC) for Year Y+1 is determined in accordance with the following equation:

$$NSPLC_{Y+1} = ACustPL_Y \times \frac{ComEdPL_Y}{\sum_{Ac} ACustPL_Y}$$

Where:

$NSPLC_{Y+1}$ = Network Service Peak Load Contribution for the customer, in kW, applicable for the period beginning with January in Year Y+1 and extending through December in Year Y+1.

$ComEdPL_Y$ = ComEd Peak Load for Year Y, in kW.

$\sum_{Ac}$ = Summation over all customers.

Notwithstanding the previous provisions describing the determination of the $NSPLC_{Y+1}$, for certain situations ComEd determines a customer's $NSPLC_{Y+1}$ to be equal to (i) the average $NSPLC_{Y+1}$ attributable to the delivery class applicable to such customer or (ii) the average $NSPLC_{Y+1}$ attributable to the delivery class applicable to such customer scaled to reflect the amount of electricity delivered to such customer. For purposes of this Attachment M-2 (ComEd), load attributable to net metering and community supply projects may reflect both consumption and generation in the NSPLC, and therefore can result in a positive or negative value for any such individual customer's calculation.

II. DAILY CAPACITY PEAK LOAD OBLIGATION AND DAILY NETWORK

SERVICE PEAK LOAD OBLIGATION

Section 1 PURPOSE

The purpose of Part II is to describe the methodology used to calculate the Daily Capacity Peak Load Obligation (DCPLO) and Daily Network Service Peak Load Obligation (DNSPLO) for Load Serving Entities (LSEs) in the ComEd Zone.

Section 2 DETERMINATION OF THE DAILY CAPACITY PEAK LOAD OBLIGATION

The Daily Capacity Peak Load Obligation (DCPLO) for a LSE in the ComEd Zone taking service under Attachment F to the PJM Tariff, but not ComEd as the EDC for the ComEd Zone, ("Attachment F LSEs in the ComEd Zone") is determined in accordance with the following equation:

$$DCPLO_{LSE} = \sum_{LSEc} CPLC$$

The DCPLO for all other LSEs in the ComEd Zone, including ComEd as the EDC for the ComEd Zone, ("Attachment F-1 LSEs in the ComEd Zone") is determined in accordance with the following equation:

:

$$DCPLO_{LSE} = \sum_{LSEc} CPLC + \left(ComEdNPL_{Y} - \sum_{Ac} CPLC\right) \times \frac{\sum_{LSEc} CPLC}{\left(\sum_{Ac} CPLC - \sum_{Am} CPLC\right)}$$

Where:

$DCPLO_{LSE}$ = Daily Capacity Peak Load Obligation for a LSE

CPLC = Capacity Peak Load Contribution for a customer

$ComEdNPL_{Y}$ = ComEd Weather Normalized Peak Load for Year Y, in kW

$\sum_{Ac}$ = Summation over all customers

$\sum_{LSEc}$ = Summation over all customers of a LSE

$\sum_{Am}$ = Summation over all Wholesale Municipalities

Section 3 DETERMINATION OF DAILY NETWORK SERVICE PEAK LOAD OBLIGATION

The Daily Network Service Peak Load Obligation (DNSPLO) for Attachment F LSEs in

the ComEd Zone is determined in accordance with the following equation:

$$DNSPLO_{LSE} = \sum_{LSEc} NSPLC$$

The DNSPLO for Attachment F-1 LSEs in the ComEd Zone, is determined in accordance with the following equation:
:

$$DNSPLO_{LSE} = \sum_{LSEc} NSPLC + \left(ComEdPL_Y - \sum_{Ac} NSPLC\right) \times \frac{\sum_{LSEc} NSPLC}{\left(\sum_{Ac} NSPLC - \sum_{Am} NSPLC\right)}$$

Where:

$DNSPLO_{LSE}$	=	Daily Network Service Peak Load Obligation for a LSE
NSPLC	=	Network Service Peak Load Contribution for a customer
ComEd PL_Y	=	ComEd Peak Load for Year Y, in kW
$\sum_{Ac}$	=	Summation over all customers
$\sum_{LSEc}$	=	Summation over all customers of a LSE
$\sum_{Am}$	=	Summation over all Wholesale Municipalities

III. FINAL HOURLY LOAD OBLIGATIONS

Section 1 PURPOSE

The purpose of Part III is to describe the methodology used to calculate the Final Hourly Load Obligation for Load Serving Entities (LSEs) in the ComEd Zone.

Section 2 DETERMINING FINAL HOURLY LOAD OBLIGATION

ComEd, on a monthly basis, will perform a load reconciliation to determine the difference between the Scheduled Hourly Load Obligation and the Final Hourly Load Obligation for LSEs in the ComEd Zone. The results of the reconciliation will be reported to PJM Interconnection, LLC ("PJM") for billing and settlement purposes.

Hourly Loads for customers shall be determined using customer meter data, adjusted for applicable distribution and transmission losses. In the event customer meter data is not available, customer Hourly Loads may be estimated.

The Final Hourly Load Obligation (FHLO) for an Attachment F LSEs in the ComEd Zone is determined in accordance with the following equation:

$$FHLO_{LSE} = \sum_{LSEc} HL$$

The FHLO for an Attachment F-1 LSE in the ComEd Zone, is determined in accordance with the following equation:
:

$$FHLO_{LSE} = \sum_{LSEc} HL + \left(ZL - \sum_{Ac} HL\right) \times \frac{\sum_{LSEc} HL}{\left(\sum_{Ac} HL - \sum_{Am} HL\right)}$$

Where:

$FHLO_{LSE}$ = Final Hourly Load Obligation for a LSE

HL = Hourly Load for a customer, adjusted to include applicable distribution and transmission losses

ZL = ComEd Zone Load

$\sum_{Ac}$ = Summation over all customers

$\sum_{LSEc}$ = Summation over all customers of a LSE

$\sum_{Am}$ = Summation over all Wholesale Municipalities

If adjustments are made to the Hourly Load of an Attachment F-1 LSE in the ComEd Zone after the load reconciliation, ComEd may calculate the financial value of the adjustment and report that value to PJM. ComEd will also allocate the equal and opposite financial value to all Attachment F-1 LSEs in the ComEd Zone, on a load-ratio-share basis, and report the adjustments to PJM. PJM will include any adjustments in the next monthly billing statement issued by PJM to the affected LSE(s).

IV. Administrative Provisions for Retail Electric Service

The terms and conditions included in this Attachment M-2, Section IV are available only for such service in the ComEd Zone, and are not available under this RTO Tariff for any transmission service outside of the ComEd Zone. The rates, terms and conditions of the Transmission Provider's Open Access Transmission Tariff apply to the Illinois Retail Access Program except as amended below.

A Retail Electric Supplier (RES) is any Alternative Retail Supplier (ARES) under Section 16-102 of the Illinois Public Utilities Act, 220 ILCS 5/16-102 or any Illinois Electric Utility as defined in Section 16-102 of the Illinois Public Utilities Act, 220 ILCS 5/16-102 and, by reference, Section 3-105 of the Illinois Public Utilities Act, 220 ILCS

5/3-105 (or any agent of any such electric utility to the extent the electric utility provides tariff services to retail customers through that agent) A utility that is not an Illinois Electric Utility as defined above is not a RES unless it qualifies as an ARES, in accordance with Illinois law, rules and regulations.

RES De-certification: In the event that the State of Illinois de-certifies a Transmission Customer who is not a retail customer under Section 1.11(ii) of the PJM Tariff, then Transmission Provider may immediately terminate Transmission Service to the de-certified Transmission Customer for the load of the retail customers supplied by such Transmission Customer, provided that Transmission Owner's retail service tariffs subject to the jurisdiction of the State of Illinois provide for continuation of service to affected retail customers as described in Section 1.11(ii) of the PJM Tariff by another supplier that is a Transmission Customer.

In the event of a de-certification, and/or upon receipt of notification from PJM that a RES is in default under PJM Tariff Section 7.3, ComEd, as EDC of the ComEd zone, will immediately assume wholesale supply obligations consistent with the terms of the ICC-approved rate schedules.

Term of Network Integration Transmission Service: The minimum term for Network Integration Transmission Service is one year or for any shorter period necessary to accommodate retail access under Illinois law.

Commencement of Service: Service under a Service Agreement for Point-to-Point Transmission Service or under a Network Service Agreement shall not commence until customer qualifies as a Transmission Customer under Transmission Provider's OATT.

JRB
EXHIBIT-6

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AN EXELON COMPANY

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June 24, 2022

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ComEd Update to Attachment M-2, FERC Docket No. ER22-1520-___

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, Part 35 of the Commission's Regulations, 18 C.F.R. Part 35, Section 9 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("PJM Tariff") and Article 7 of the Consolidated Transmission Owners Agreement, PJM Rate Schedule No. 42,[1] Exelon Corporation ("Exelon"), on behalf of its affiliates Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc. (collectively, "ComEd"), submits for filing the following response to the letter from Kurt M. Longo, Director, Division of Electric Power Regulation – East, to the undersigned date May 26, 2022 ("Deficiency Letter"). The Deficiency Letter advises ComEd that its March 31, 2022 filing in this proceeding (March 31 Filing) is deficient and that additional information is required in order to process the filing. ComEd's responses to the questions contained in the Deficiency Letter are set forth below and in attachments to this filing.[2] ComEd requests that the Commission accept the revision to Attachment M-2 (ComEd), effective September 1, 2022.

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[1] Pursuant to Order No. 714, this filing is submitted by PJM on behalf of Exelon as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. Thus, Exelon has requested PJM submit this Tariff revision in the eTariff system as part of PJM's electronic Intra PJM Tariff.

[2] Footnote 5 of the Deficiency Letter requires this response "include at least one tariff record to restart the statutory timeframe for Commission action even though a tariff revision might not otherwise be needed." To satisfy this directive, ComEd is resubmitting in Attachments 1 and 2 hereto, all of the same tariff records initially submitted in the March 31 Filing (i.e., Attachments 1 and 2 provided, respectively, marked and clean

ComEd also notes that, while the original filing was protested by Illinois Industrial Energy Consumers ("IIEC"), ComEd and IIEC have reached a resolution that sufficiently addresses IIEC's concerns. Consequently, IIEC has withdrawn its Protest,[3] and there are no outstanding protested issues that require resolution.

I. Responses To Deficiency Letter

On March 31, 2022, ComEd filed revisions to Attachment M-2 (ComEd) to the PJM Tariff to incorporate proposed changes in response to recent Illinois legislation. Attachment M-2's sole purpose is to allocate costs related to capacity and transmission network service to load serving entities (LSEs) serving customers in the ComEd zone. At the outset, it is important to note that the modest changes proposed by ComEd to its Attachment M-2 are intended to align with current Illinois state law and improve the cost allocation methodology in way that ensures the LSEs whose customers install renewable generating systems on their homes and businesses, or develop community supply projects, receive directly the capacity and transmission cost reductions that their systems provide to all customers within the ComEd zone. This cost allocation improvement is accomplished simply by removing the "hard floor" of a zero value and allowing an individual's peak load contribution (PLC) and network system peak load (NSPL) values to be negative to the extent a customer's solar system is a net producer in the hours used to calculate PLCs and NSPLs, as these systems are in fact reducing the peak demand on the system during these critical hours by providing generation to the grid from which all customers in the zone benefit. In no instance will an LSEs capacity or transmission system costs be allowed to go negative, in accordance with PJM's OATT which expressly prohibits an LSE from having a negative PLC and or NSPL.[4] Additionally, as stated in response to Request No. 2(b) below, ComEd's proposed revisions do not alter the calculation of "daily load," and as such do not reduce the ComEd zone's daily load as a Network Customer by energy injections into the transmission system.

Deficiency Letter Request No. 1(a):

1. ComEd states that "although the methodology for calculating and reporting to PJM the ComEd load will not change as a result of this filing, certain individual customers' peak load contribution chares of that ComEd load will change."

   a. Please explain what class(es) of customer will be affected by the proposal and whether such customers are retail or wholesale customers.

---

tariff sheets of the proposed changes to ComEd's Attachment M-2). ComEd does not propose any tariff revisions in this response, so the tariff records in Attachments 1 and 2 are identical to those in the March 31 Filing.

[3] *See* Notice of Withdrawal of the Illinois Industrial Energy Consumers' Protest, FERC Docket No. ER22-1520-000 (May 10, 2022).

[4] *See* PJM Manual 14D, Appendix A: Behind the Meter Generation Business Rules, Rule #40, available at http://www.pjm.com/-/media/documents/manuals/m14d.ashx.

ComEd Response:

The proposed changes to Attachment M-2 will directly affect only retail customers that own a solar generation system, and specifically those systems that generate energy at the time of peak load – that is, during the five highest daily peaks, as measured on an hourly basis, during the previous summer[5] - to the extent they are "net producers" of energy. Nevertheless, all customers will be indirectly affected due to the resulting change in each customers' proportional share of PLC and NSPL responsibilities. Though the PLC and NSPL calculations are performed on an individual account level, all retail customers are assigned to a wholesale Load Serving Entity. The sum of all customers' PLC and NSPL values for each Load Serving Entity are then reported to PJM for the ComEd zone. Thus, the reduction in the revised PLC and NSPL values will be shared across all Load Serving Entities since they still must sum to the ComEd zone load, although as previously stated a Load Serving Entity's PLC and NSPL values cannot be less than zero.

Deficiency Letter Request No. 1(b):

b. In your response, please provide an example that illustrates how the changes in customer's peak load share would impact a sample calculation.

ComEd Response:

Please find attached as Exhibit 1(b) a sample calculation for a net metering customer.

Deficiency Letter Request No. 2(a):

2. ComEd's proposed tariff revisions state that "load attributable to net metering and community supply projects may reflect both consumption and generation in the [capacity peak load contribution], and therefore can result in a positive or negative value for any such individual customer's calculation."

   a. Please provide definitions of "net metering" and "community supply projects." Also, please provide examples of each project class. If applicable, please describe these terms using defined terms found in the PJM Tariff.

ComEd Response:

"Net electricity metering" or "net metering" means measurement during the billing period applicable to an eligible customer[6] of the net amount of electricity supplied by an electricity

[5] PLC values are based on the PJM five highest measurements, while NSPL values are based on the ComEd zone five highest.

[6] "eligible customer" means a retail customer that owns, hosts, or operates, including any third-party owned systems, a solar, wind, or other eligible renewable electrical generating facility that is located on the customer's premises or customer's side of the billing meter and is intended primarily to offset the customer's own current or future electrical requirements." 220 ILCS 5/16-107.5(b).

provider to the customer's premises or provided to the electricity provider by the customer." Title 83 Illinois Administrative Code Part 465.5. A net metering retail customer takes service under ComEd's net metering tariff, Rider POGNM – Parallel Operation of Retail Customer Generating Facilities with Net Metering ("Rider POGNM").

"Community supply projects" are defined in ComEd's community supply tariff, Rider POGCS – Parallel Operation of Retail Customer Generating Facilities Community Supply ("Rider POGCS"), as "a renewable generating facility that is a nonresidential retail customer taking electric service under Rate [Basic Electric Service] and that includes (a) properties owned or leased by multiple retail customers that contribute to the operation of a renewable generating facility though an ownership or leasehold interest of at least 200 watts in such facility, such as a community-owned wind project, a community-owned biomass project, a community-owned solar project, or a community methane digester processing livestock waste from multiple sources, provided that the facility is also located within the utility's service territory; (b) individual units, apartments, or properties located in a single building that are owned or leased by multiple retail customers and collectively served by a common renewable generating facility, such as an office or apartment building, a shopping center or strip mall served by photovoltaic panels on the roof; or (c) a community renewable generation project as defined in Section 1-10 of the IPA Act, including community renewable generation projects on the retail customer's side of the Company-provided meter-related facilities for billing purposes of a host facility and partially used for the retail customer's own load." ILL. C. C. No. 10, Rider POGCS, 1st Revised Sheet No. 344.1.

Deficiency Letter Request No. 2(b):

b. Please explain how ComEd will determine the "consumption and generation" in the capacity peak load contribution for each individual customer's calculation and how "consumption and generation" will be used to calculate each individual customer's capacity peak load contribution. In addition to a narrative explanation, please provide numerical examples reflecting both consumption and generation and positive and negative capacity peak load contributions.

ComEd Response:

Net metering customers have a meter that measures energy flow into the customer's premise (consumption) as well as energy flow from the customer's premise to the ComEd system (generation). The consumption is measured and recorded on one channel, and the generation provided to the grid is measured and recorded on a different channel. The consumption is referred to as "Sold to Customer" and the generation is referred to as "Bought from Customer". Under the proposal, net metering customers will receive full credit for generation ("Bought from Customer") during the 10 system peak hours. Previously, only the netted consumption ("Sold to Customer") was used, with a floor of zero for a given half-

hour. Similarly, community supply projects will receive credit for all generation during the 10 system peak hours, where previously only the netted energy consumption ("Sold to Customer") was used with a floor of zero for a given half-hour. Additional adjustments to the calculations will remain unchanged. Please see attached Exhibits 2(b)(i) and 2(b)(ii) for numerical examples reflecting both consumption and generation and positive and negative capacity peak load contributions.

Deficiency Letter Request No. 2(c):

c. Please explain if any net metering and community supply projects include Behind the Meter Generation. If so, please explain how the proposed tariff revisions comport with PJM Tariff section 34.2, which states that the "daily load of a Network Customer shall not be reduced by energy injections into the transmission system by the Network Customer."

ComEd Response:

Functionally, both net metering customers and community supply projects may literally meet the definition of Behind the Meter Generation as defined in the PJM OATT. However, under Illinois law and ComEd tariffs, net metering and community supply projects do not currently include facilities that participate in the PJM wholesale markets.

ComEd's proposed revisions comport with the PJM Tariff because ComEd's proposed revisions do not alter the calculation of "daily load," and as such do not reduce ComEd's daily load as a Network Customer by energy injections into the transmission system. Rather, ComEd's revisions only result in changes to individual retail customers' proportional share of ComEd's peak load obligation.

Deficiency Letter Request No. 2(d):

d. Please explain how the benefits received by net metering and community supply projects customers from the proposed credits are commensurate with the costs associated with those credits.

ComEd Response:

PJM's peak load forecast recognizes the value of net metering and community solar projects by reducing the peak demand forecasted for ComEd's zone. When PJM procures capacity, it does so on the basis of that reduced peak demand calculation. This peak demand reduction, and the resulting reduction in the cost of capacity procured, inures to the benefit of all customers in the ComEd zone. Nevertheless, net metering customers and community supply projects that produce more energy than they use during the five highest daily peaks may fail to receive the full value of providing that reduction because their contribution is artificially limited to zero. Under the narrowly tailored changes proposed by ComEd to Attachment M-

2, those net metering customers and community supply projects will better recognize the value they provide to the system, as the benefits will accrue to the LSEs serving those customers. The LSEs serving the net metering and community solar projects are the entities providing the capacity and transmission credits to those customers and therefore should be the entities that receive the benefits of the lower capacity costs resulting from PJM's recognition of the capacity reduction benefit provided by those projects instead of those benefits being spread over all LSEs regardless of their customers' contribution to the capacity cost reduction which is what happens today under the current methodology.

II. Information Required Under Part 35 of the Commission's Regulations

A. Documents Submitted with this Filing

Exelon is filing herewith the following documents:

1. This response to Deficiency Letter;
2. Exhibit 1(b)
3. Exhibit 2(b)(i)
4. Exhibit 2(b)(ii)
5. Marked Version of Attachment M-2 (ComEd) (Attachment 1); and
6. Clean Version of Attachment M-2 (ComEd) (Attachment 2).

B. Proposed Effective Date

Pursuant to Section 35.11 of the Commission's regulation, Exelon respectfully requests that the Commission issue an order accepting the proposed revisions to Attachment M-2 (ComEd) to be effective September 1, 2022.

C. Designation

The enclosed tariff changes are included in Attachment M-2 (ComEd) under the PJM Tariff.

D. Service

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's Regulations, *see* 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3), PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://www.pjm.com/library/filing-order with a specific link to the

newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[7] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http://elibrary.ferc.gov in accordance with the Commission's Regulations and Order No. 714.

V. Conclusion

Exelon requests that the Commission issue an order accepting the proposed changes to be effective on September 1, 2022.

Sincerely,

Lisa B. Luftig
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Attorney for Exelon, on behalf of Commonwealth Edison Company

Enclosures

[7] PJM already maintains, updates, and regularly uses e-mail lists for all PJM Members and affected state commissions.

Exhibit 1(b)

Difference of the Average ComEd and Average PJM 5 CPs for Weather Sensitive Customers (kW)
2,033,653

Summer 2021 Weather Normalized PJM Coincident Peak (MW)	Summer 2021 ComEd Zone PJM Coincident 5 CPs (MW)	Allocation to Weather Sensitive Load (MW)
20,290	**18,491**	**1,798.5104**

ComEd Peaks (HE CPT)	ComEd Zonal Load (MW)
8/24/21 4:00 PM	21,167.2
8/10/21 5:00 PM	20,454.7
8/25/21 4:00 PM	19,903.7
8/27/21 5:00 PM	19,861.9
7/6/21 4:00 PM	19,453.9
Average	**20,168.263**
NSPL Scaling Factor =	**1.04953**

PJM Peaks (HE CPT)	ComEd Zonal Load (MW)
8/24/21 5:00 PM	20,933.6
7/6/21 4:00 PM	19,453.9
8/26/21 3:00 PM	18,851.6
6/29/21 4:00 PM	16,704.8
8/12/21 4:00 PM	16,513.6
Average	**18,491.490**

Account Number	11111-11111
Customer Name	Customer 1
Delivery Service Class Code	C23
Delivery Service Class Name	RESIDENTIAL SINGLE

ComEd Peaks (HE CPT)	Metered Usage (kW)	Generation (kW)	Metered Usage with Losses Applied (kW)	Metered Usage with Losses and UFT Applied (kW)
8/24/21 4:00 PM	0.0000	-2.6575	-2.8442	-2.8489
8/10/21 5:00 PM	0.0000	-1.5300	-1.6375	-1.6402
8/25/21 4:00 PM	0.0000	-2.3000	-2.4616	-2.4657
8/27/21 5:00 PM	0.0000	-2.6425	-2.8281	-2.8328
7/6/21 4:00 PM	0.0000	-3.5950	-3.8476	-3.8540
Average	0.0000	-2.5450	-2.72380	-2.7283

Original	Proposed
PY 2022 NSPL value (kW)	**PY 2022 NSPL value (kW)**
0.0000	**-2.8635**

PJM Peaks (HE CPT)	Metered Usage (kW)	Generation (kW)	Metered Usage with Losses Applied (kW)	Metered Usage with Losses and UFC Applied (kW)
8/24/21 5:00 PM	0.0000	-2.3100	-2.4723	-2.4737
7/6/21 4:00 PM	0.0000	-3.5950	-3.8476	-3.8497
8/26/21 3:00 PM	0.0000	-2.3450	-2.5097	-2.5111
6/29/21 4:00 PM	0.0000	-1.3125	-1.4047	-1.4055
8/12/21 4:00 PM	0.0000	-0.8300	-0.8883	-0.8888
Average	0.0000	-2.0785	-2.22452	-2.2258

Original	Proposed
PY 2022 PLC value (kW)	**PY 2022 PLC value (kW)**
0.0000	**-2.2258**

ComEd 5CP - PJM 5CP (kW)	Is customer Weather Sensitive?	Customer Weather Sensitivity Adjustment (kW)
-0.50257	**No**	0.0000

Exhibit 2(b)(i)

Difference of the Average ComEd and Average PJM 5 CPs for Weather Sensitive Customers (kW)
2,033,653

Summer 2021 Weather Normalized PJM Coincident Peak (MW)	Summer 2021 ComEd Zone PJM Coincident 5 CPs (MW)	Allocation to Weather Sensitive Load (MW)
20,290	**18,491**	**1,798.5104**

ComEd Peaks (HE CPT)	ComEd Zonal Load (MW)
8/24/21 4:00 PM	21,167.2
8/10/21 5:00 PM	20,454.7
8/25/21 4:00 PM	19,903.7
8/27/21 5:00 PM	19,861.9
7/6/21 4:00 PM	19,453.9
Average	**20,168.263**
NSPL Scaling Factor =	**1.04953**

PJM Peaks (HE CPT)	ComEd Zonal Load (MW)
8/24/21 5:00 PM	20,933.6
7/6/21 4:00 PM	19,453.9
8/26/21 3:00 PM	18,851.6
6/29/21 4:00 PM	16,704.8
8/12/21 4:00 PM	16,513.6
Average	**18,491.490**

Account Number	11111-11111
Customer Name	Customer 1
Delivery Service Class Code	C23
Delivery Service Class Name	RESIDENTIAL SINGLE

ComEd Peaks (HE CPT)	Metered Usage (kW)	Generation (kW)	Metered Usage with Losses Applied (kW)	Metered Usage with Losses and UFT Applied (kW)
8/24/21 4:00 PM	0.0000	-2.6575	-2.8442	-2.8489
8/10/21 5:00 PM	0.0000	-1.5300	-1.6375	-1.6402
8/25/21 4:00 PM	0.0000	-2.3000	-2.4616	-2.4657
8/27/21 5:00 PM	0.0000	-2.6425	-2.8281	-2.8328
7/6/21 4:00 PM	0.0000	-3.5950	-3.8476	-3.8540
Average	0.0000	-2.5450	-2.72380	-2.7283

Original	Proposed
PY 2022 NSPL value (kW)	**PY 2022 NSPL value (kW)**
0.0000	**-2.8635**

PJM Peaks (HE CPT)	Metered Usage (kW)	Generation (kW)	Metered Usage with Losses Applied (kW)	Metered Usage with Losses and UFC Applied (kW)
8/24/21 5:00 PM	0.0000	-2.3100	-2.4723	-2.4737
7/6/21 4:00 PM	0.0000	-3.5950	-3.8476	-3.8497
8/26/21 3:00 PM	0.0000	-2.3450	-2.5097	-2.5111
6/29/21 4:00 PM	0.0000	-1.3125	-1.4047	-1.4055
8/12/21 4:00 PM	0.0000	-0.8300	-0.8883	-0.8888
Average	0.0000	-2.0785	-2.22452	-2.2258

Original	Proposed
PY 2022 PLC value (kW)	**PY 2022 PLC value (kW)**
0.0000	**-2.2258**

ComEd 5CP - PJM 5CP (kW)	Is customer Weather Sensitive?	Customer Weather Sensitivity Adjustment (kW)
-0.50257	**No**	0.0000

Exhibit 2(b)(ii)

Difference of the Average ComEd and Average PJM 5 CPs for Weather Sensitive Customers (kW)
2,033,653

Summer 2021 Weather Normalized PJM Coincident Peak (MW)	Summer 2021 ComEd Zone PJM Coincident 5 CPs (MW)	Allocation to Weather Sensitive Load (MW)
20,290	**18,491**	**1,798.5104**

ComEd Peaks (HE CPT)	ComEd Zonal Load (MW)
8/24/21 4:00 PM	21,167.2
8/10/21 5:00 PM	20,454.7
8/25/21 4:00 PM	19,903.7
8/27/21 5:00 PM	19,861.9
7/6/21 4:00 PM	19,453.9
Average	**20,168.263**
NSPL Scaling Factor =	**1.04953**

PJM Peaks (HE CPT)	ComEd Zonal Load (MW)
8/24/21 5:00 PM	20,933.6
7/6/21 4:00 PM	19,453.9
8/26/21 3:00 PM	18,851.6
6/29/21 4:00 PM	16,704.8
8/12/21 4:00 PM	16,513.6
Average	**18,491.490**

Account Number	22222-22222
Customer Name	Customer 2
Delivery Service Class Code	C28
Delivery Service Class Name	SMALL (0 - 100)

ComEd Peaks (HE CPT)	Metered Usage (kW)	Generation (kW)	Metered Usage with Losses Applied (kW)	Metered Usage with Losses and UFT Applied (kW)
8/24/21 4:00 PM	0.6075	-0.8000	-0.2058	-0.2062
8/10/21 5:00 PM	7.0125	0.0000	7.4973	7.5098
8/25/21 4:00 PM	0.0075	-0.1975	-0.2031	-0.2035
8/27/21 5:00 PM	0.5050	-0.7100	-0.2192	-0.2195
7/6/21 4:00 PM	0.0000	-1.8800	-2.0100	-2.0133
Average	1.6265	-0.7175	0.97185	0.9735

Proposed PY 2022 NSPL value (kW)	Original PY 2022 NSPL value (kW)
1.0217	**1.8281**

PJM Peaks (HE CPT)	Metered Usage (kW)	Generation (kW)	Metered Usage with Losses Applied (kW)	Metered Usage with Losses and UFC Applied (kW)
8/24/21 5:00 PM	1.8250	-0.0575	1.8897	1.8907
7/6/21 4:00 PM	0.0000	-1.8800	-2.0100	-2.0111
8/26/21 3:00 PM	0.0000	-1.2875	-1.3765	-1.3773
6/29/21 4:00 PM	0.0000	-0.6700	-0.7163	-0.7167
8/12/21 4:00 PM	5.3575	0.0000	5.7279	5.7311
Average	1.4365	-0.7790	0.70296	0.7033

Proposed PY 2022 PLC value (kW)	Original PY 2022 PLC value (kW)
0.9422	**1.7181**

ComEd 5CP - PJM 5CP (kW)	Is customer Weather Sensitive?	Customer Weather Sensitivity Adjustment (kW)
0.27012	**Yes**	0.2389

ATTACHMENT 1

MARKED TARIFF SHEETS

PJM TARIFF ATTACHMENT M-2 (ComEd)

ATTACHMENT M-2 (ComEd)

Determination of Capacity Peak Load Contributions, Network Service Peak Load Contributions, Daily Peak Load Obligation , Daily Network Service Peak Load Obligation, and Hourly Load Obligations

I. CAPACITY AND NETWORK SERVICE PEAK LOAD CONTRIBUTIONS

Section 1 PURPOSE

The purpose of Part I. is to describe the methodology used to determine capacity and network service peak load contributions for electric power and energy attributable to customers located in the ComEd Zone.

Section 2 DEFINITIONS

The following definitions are for use in this Attachment M-2. Capitalized terms used and not defined in this Attachment M-2 but defined in other provisions of the PJM OATT have the meaning given them under those provisions. Capitalized terms used in this Attachment M-2 that are not defined in it or elsewhere in the PJM OATT have the meanings customarily attributed to such terms by the electric utility industry in PJM.

a) **Average ComEd Coincident Peak Load:** the average of the sum of the (i) five (5) ComEd Zonal Loads established during the PJM Five Peaks in a summer and (ii) the corresponding Load Drop Estimates for such PJM Five Peaks.

b) **Average ComEd Peak Load:** the average of the five (5) ComEd Zonal Loads established during the ComEd Five Peaks in a summer.

c) **Average Customer Coincident Peak Load:** the average of the sum of the (i) five (5) customer loads established during the PJM Five Peaks in a summer and (ii) the corresponding Load Drop Estimates for such customer, with such sum adjusted to include applicable distribution and transmission system losses.

d) **Average Customer Peak Load:** the average of the five (5) loads established by the customer during the ComEd Five Peaks in a summer, with such loads adjusted to include applicable distribution and transmission system losses.

e) **ComEd Five Peaks:** the five hours occurring on different calendar days in a summer during which the electric system served by ComEd experiences its five highest daily summer demands.

f) **ComEd Weather Normalized Peak Load:** the expected ComEd Zonal Load at the time of the PJM system peak load in a summer under normal weather conditions as determined by PJM.

g) **ComEd Peak Load:** the highest ComEd Zonal Load established for PJM network service in a summer.

h) **ComEd Zonal Load:** the demand for electricity placed upon the interconnected electricity system operated by PJM that is attributable to customers located in the ComEd Zone.

i) **Load Drop Estimate:** the kilowatt (kW) value attributable to curtailed demand as determined by PJM.

j) **PJM Five Peaks:** the five hours occurring on different calendar days in a summer during which the electric system served by PJM experiences its five highest daily summer demands.

k) **Summer:** the period beginning June 1 and extending through September 30 in a calendar year.

Section 3 DETERMINATION OF THE CAPACITY PEAK LOAD CONTRIBUTION

If a customer's Average Customer Coincident Peak Load for Year Y is greater than or equal to such customer's Average Customer Peak Load for Year Y, then such customer's capacity peak load contribution (CPLC) for year Y+1 is equal to such customer's Average Customer Coincident Peak Load for Year Y.

If a customer's Average Customer Coincident Peak Load for Year Y is less than such customer's Average Customer Peak Load for Year Y, then such customer's CPLC for year Y+1 is determined in accordance with the following equation:

$$CPLC_{Y+1} = ACustCPL_Y + \left(ComEdNPL_Y - AComEdCPL_Y\right) \times \frac{ACustPL_Y - ACustCPL_Y}{\sum_{5Pc}\left(ACustPL_Y - ACustCPL_Y\right)}$$

Where:

$CPLC_{Y+1}$ = Capacity Peak Load Contribution for the customer, in kW, applicable for the period beginning with June in Year Y+1 and extending through May in Year Y+2.

$ACustCPL_Y$ = Average Customer Coincident Peak Load for the customer for Year Y, in kW.

$ACustPL_Y$ = Average Customer Peak Load for the customer for Year Y, in kW.

$ComEdNPL_Y$ = ComEd Weather Normalized Peak Load for Year Y, in kW.

$AComEdCPL_Y$ = Average ComEd Coincident Peak Load for Year Y, in kW.

$\sum_{5Pc}$ = Summation over all customers for which the Average Customer

Coincident Peak Load for Year Y is less than the Average Customer Peak Load for Year Y.

Notwithstanding the previous provisions describing the determination of the $CPLC_{Y+1}$, for certain situations ComEd determines a customer's $CPLC_{Y+1}$ to be equal to (i) the average $CPLC_{Y+1}$ attributable to the delivery class applicable to such customer or (ii) the average $CPLC_{Y+1}$ attributable to the delivery class applicable to such customer scaled to reflect the amount of electricity delivered to such customer. Delivery classes are as described in the General Terms and Conditions of ComEd's Schedule of Rates filed with the Illinois Commerce Commission (Ill. C.C. No. 10). For purposes of this Attachment M-2 (ComEd), load attributable to net metering and community supply projects may reflect both consumption and generation in the CPLC, and therefore can result in a positive or negative value for any such individual customer's calculation.

Section 4 DETERMINATION OF THE NETWORK SERVICE PEAK LOAD CONTRIBUTION

A customer's Network Service Peak Load Contribution (NSPLC) for Year Y+1 is determined in accordance with the following equation:

$$NSPLC_{Y+1} = ACustPL_Y \times \frac{ComEdPL_Y}{\sum_{Ac} ACustPL_Y}$$

Where:

$NSPLC_{Y+1}$ = Network Service Peak Load Contribution for the customer, in kW, applicable for the period beginning with January in Year Y+1 and extending through December in Year Y+1.

$ComEdPL_Y$ = ComEd Peak Load for Year Y, in kW.

$\sum_{Ac}$ = Summation over all customers.

Notwithstanding the previous provisions describing the determination of the $NSPLC_{Y+1}$, for certain situations ComEd determines a customer's $NSPLC_{Y+1}$ to be equal to (i) the average $NSPLC_{Y+1}$ attributable to the delivery class applicable to such customer or (ii) the average $NSPLC_{Y+1}$ attributable to the delivery class applicable to such customer scaled to reflect the amount of electricity delivered to such customer. For purposes of this Attachment M-2 (ComEd), load attributable to net metering and community supply projects may reflect both consumption and generation in the NSPLC, and therefore can result in a positive or negative value for any such individual customer's calculation.

II. DAILY CAPACITY PEAK LOAD OBLIGATION AND DAILY NETWORK SERVICE PEAK LOAD OBLIGATION

Section 1 PURPOSE

The purpose of Part II is to describe the methodology used to calculate the Daily Capacity Peak Load Obligation (DCPLO) and Daily Network Service Peak Load Obligation (DNSPLO) for Load Serving Entities (LSEs) in the ComEd Zone.

Section 2 DETERMINATION OF THE DAILY CAPACITY PEAK LOAD OBLIGATION

The Daily Capacity Peak Load Obligation (DCPLO) for a LSE in the ComEd Zone taking service under Attachment F to the PJM Tariff, but not ComEd as the EDC for the ComEd Zone, ("Attachment F LSEs in the ComEd Zone") is determined in accordance with the following equation:

$$DCPLO_{LSE} = \sum_{LSEc} CPLC$$

The DCPLO for all other LSEs in the ComEd Zone, including ComEd as the EDC for the ComEd Zone, ("Attachment F-1 LSEs in the ComEd Zone") is determined in accordance with the following equation:

:

$$DCPLO_{LSE} = \sum_{LSEc} CPLC + \left(ComEdNPL_Y - \sum_{Ac} CPLC\right) \times \frac{\sum_{LSEc} CPLC}{\left(\sum_{Ac} CPLC - \sum_{Am} CPLC\right)}$$

Where:

$DCPLO_{LSE}$	=	Daily Capacity Peak Load Obligation for a LSE
CPLC	=	Capacity Peak Load Contribution for a customer
$ComEdNPL_Y$	=	ComEd Weather Normalized Peak Load for Year Y, in kW
$\sum_{Ac}$	=	Summation over all customers
$\sum_{LSEc}$	=	Summation over all customers of a LSE
$\sum_{Am}$	=	Summation over all Wholesale Municipalities

Section 3 DETERMINATION OF DAILY NETWORK SERVICE PEAK LOAD OBLIGATION

The Daily Network Service Peak Load Obligation (DNSPLO) for Attachment F LSEs in the ComEd Zone is determined in accordance with the following equation:

$$DNSPLO_{LSE} = \sum_{LSEc} NSPLC$$

The DNSPLO for Attachment F-1 LSEs in the ComEd Zone, is determined in accordance with the following equation:
:

$$DNSPLO_{LSE} = \sum_{LSEc} NSPLC + \left(ComEdPL_{Y} - \sum_{Ac} NSPLC\right) \times \frac{\sum_{LSEc} NSPLC}{\left(\sum_{Ac} NSPLC - \sum_{Am} NSPLC\right)}$$

Where:

$DNSPLO_{LSE}$	=	Daily Network Service Peak Load Obligation for a LSE
NSPLC	=	Network Service Peak Load Contribution for a customer
ComEd PL_Y	=	ComEd Peak Load for Year Y, in kW
$\sum_{Ac}$	=	Summation over all customers
$\sum_{LSEc}$	=	Summation over all customers of a LSE
$\sum_{Am}$	=	Summation over all Wholesale Municipalities

III. FINAL HOURLY LOAD OBLIGATIONS

Section 1 PURPOSE

The purpose of Part III is to describe the methodology used to calculate the Final Hourly Load Obligation for Load Serving Entities (LSEs) in the ComEd Zone.

Section 2 DETERMINING FINAL HOURLY LOAD OBLIGATION

ComEd, on a monthly basis, will perform a load reconciliation to determine the difference between the Scheduled Hourly Load Obligation and the Final Hourly Load Obligation for LSEs in the ComEd Zone. The results of the reconciliation will be reported to PJM Interconnection, LLC ("PJM") for billing and settlement purposes.

Hourly Loads for customers shall be determined using customer meter data, adjusted for applicable distribution and transmission losses. In the event customer meter data is not available, customer Hourly Loads may be estimated.

The Final Hourly Load Obligation (FHLO) for an Attachment F LSEs in the ComEd Zone is determined in accordance with the following equation:

$$FHLO_{LSE} = \sum_{LSEc} HL$$

The FHLO for an Attachment F-1 LSE in the ComEd Zone, is determined in accordance with the following equation:
:

$$FHLO_{LSE} = \sum_{LSEc} HL + \left(ZL - \sum_{Ac} HL\right) \times \frac{\sum_{LSEc} HL}{\left(\sum_{Ac} HL - \sum_{Am} HL\right)}$$

Where:

FHLO$_{LSE}$ = Final Hourly Load Obligation for a LSE

HL = Hourly Load for a customer, adjusted to include applicable distribution and transmission losses

ZL = ComEd Zone Load

$\sum_{Ac}$ = Summation over all customers

$\sum_{LSEc}$ = Summation over all customers of a LSE

$\sum_{Am}$ = Summation over all Wholesale Municipalities

If adjustments are made to the Hourly Load of an Attachment F-1 LSE in the ComEd Zone after the load reconciliation, ComEd may calculate the financial value of the adjustment and report that value to PJM. ComEd will also allocate the equal and opposite financial value to all Attachment F-1 LSEs in the ComEd Zone, on a load-ratio-share basis, and report the adjustments to PJM. PJM will include any adjustments in the next monthly billing statement issued by PJM to the affected LSE(s).

IV. Administrative Provisions for Retail Electric Service

The terms and conditions included in this Attachment M-2, Section IV are available only for such service in the ComEd Zone, and are not available under this RTO Tariff for any transmission service outside of the ComEd Zone. The rates, terms and conditions of the Transmission Provider's Open Access Transmission Tariff apply to the Illinois Retail Access Program except as amended below.

A Retail Electric Supplier (RES) is any Alternative Retail Supplier (ARES) under Section 16-102 of the Illinois Public Utilities Act, 220 ILCS 5/16-102 or any Illinois Electric Utility as defined in Section 16-102 of the Illinois Public Utilities Act, 220 ILCS

5/16-102 and, by reference, Section 3-105 of the Illinois Public Utilities Act, 220 ILCS 5/3-105 (or any agent of any such electric utility to the extent the electric utility provides tariff services to retail customers through that agent) A utility that is not an Illinois Electric Utility as defined above is not a RES unless it qualifies as an ARES, in accordance with Illinois law, rules and regulations.

RES De-certification: In the event that the State of Illinois de-certifies a Transmission Customer who is not a retail customer under Section 1.11(ii) of the PJM Tariff, then Transmission Provider may immediately terminate Transmission Service to the de-certified Transmission Customer for the load of the retail customers supplied by such Transmission Customer, provided that Transmission Owner's retail service tariffs subject to the jurisdiction of the State of Illinois provide for continuation of service to affected retail customers as described in Section 1.11(ii) of the PJM Tariff by another supplier that is a Transmission Customer.

In the event of a de-certification, and/or upon receipt of notification from PJM that a RES is in default under PJM Tariff Section 7.3, ComEd, as EDC of the ComEd zone, will immediately assume wholesale supply obligations consistent with the terms of the ICC-approved rate schedules.

Term of Network Integration Transmission Service: The minimum term for Network Integration Transmission Service is one year or for any shorter period necessary to accommodate retail access under Illinois law.

Commencement of Service: Service under a Service Agreement for Point-to-Point Transmission Service or under a Network Service Agreement shall not commence until customer qualifies as a Transmission Customer under Transmission Provider's OATT.

ATTACHMENT 2

CLEAN TARIFF SHEETS

PJM TARIFF ATTACHMENT M-2 (ComEd)

ATTACHMENT M-2 (ComEd)

Determination of Capacity Peak Load Contributions, Network Service Peak Load Contributions, Daily Peak Load Obligation , Daily Network Service Peak Load Obligation, and Hourly Load Obligations

I. CAPACITY AND NETWORK SERVICE PEAK LOAD CONTRIBUTIONS

Section 1 PURPOSE

The purpose of Part I. is to describe the methodology used to determine capacity and network service peak load contributions for electric power and energy attributable to customers located in the ComEd Zone.

Section 2 DEFINITIONS

The following definitions are for use in this Attachment M-2. Capitalized terms used and not defined in this Attachment M-2 but defined in other provisions of the PJM OATT have the meaning given them under those provisions. Capitalized terms used in this Attachment M-2 that are not defined in it or elsewhere in the PJM OATT have the meanings customarily attributed to such terms by the electric utility industry in PJM.

a) **Average ComEd Coincident Peak Load:** the average of the sum of the (i) five (5) ComEd Zonal Loads established during the PJM Five Peaks in a summer and (ii) the corresponding Load Drop Estimates for such PJM Five Peaks.

b) **Average ComEd Peak Load:** the average of the five (5) ComEd Zonal Loads established during the ComEd Five Peaks in a summer.

c) **Average Customer Coincident Peak Load:** the average of the sum of the (i) five (5) customer loads established during the PJM Five Peaks in a summer and (ii) the corresponding Load Drop Estimates for such customer, with such sum adjusted to include applicable distribution and transmission system losses.

d) **Average Customer Peak Load:** the average of the five (5) loads established by the customer during the ComEd Five Peaks in a summer, with such loads adjusted to include applicable distribution and transmission system losses.

e) **ComEd Five Peaks:** the five hours occurring on different calendar days in a summer during which the electric system served by ComEd experiences its five highest daily summer demands.

f) **ComEd Weather Normalized Peak Load:** the expected ComEd Zonal Load at the time of the PJM system peak load in a summer under normal weather conditions as determined by PJM.

g) **ComEd Peak Load:** the highest ComEd Zonal Load established for PJM network service in a summer.

h) **ComEd Zonal Load:** the demand for electricity placed upon the interconnected electricity system operated by PJM that is attributable to customers located in the ComEd Zone.

i) **Load Drop Estimate:** the kilowatt (kW) value attributable to curtailed demand as determined by PJM.

j) **PJM Five Peaks:** the five hours occurring on different calendar days in a summer during which the electric system served by PJM experiences its five highest daily summer demands.

k) **Summer:** the period beginning June 1 and extending through September 30 in a calendar year.

Section 3 DETERMINATION OF THE CAPACITY PEAK LOAD CONTRIBUTION

If a customer's Average Customer Coincident Peak Load for Year Y is greater than or equal to such customer's Average Customer Peak Load for Year Y, then such customer's capacity peak load contribution (CPLC) for year Y+1 is equal to such customer's Average Customer Coincident Peak Load for Year Y.

If a customer's Average Customer Coincident Peak Load for Year Y is less than such customer's Average Customer Peak Load for Year Y, then such customer's CPLC for year Y+1 is determined in accordance with the following equation:

$$CPLC_{Y+1} = ACustCPL_Y + \left(ComEdNPL_Y - AComEdCPL_Y\right) \times \frac{ACustPL_Y - ACustCPL_Y}{\sum_{5Pc}\left(ACustPL_Y - ACustCPL_Y\right)}$$

Where:

$CPLC_{Y+1}$ = Capacity Peak Load Contribution for the customer, in kW, applicable for the period beginning with June in Year Y+1 and extending through May in Year Y+2.

$ACustCPL_Y$ = Average Customer Coincident Peak Load for the customer for Year Y, in kW.

$ACustPL_Y$ = Average Customer Peak Load for the customer for Year Y, in kW.

$ComEdNPL_Y$ = ComEd Weather Normalized Peak Load for Year Y, in kW.

$AComEdCPL_Y$ = Average ComEd Coincident Peak Load for Year Y, in kW.

$\sum_{5Pc}$ = Summation over all customers for which the Average Customer

Coincident Peak Load for Year Y is less than the Average Customer Peak Load for Year Y.

Notwithstanding the previous provisions describing the determination of the $CPLC_{Y+1}$, for certain situations ComEd determines a customer's $CPLC_{Y+1}$ to be equal to (i) the average $CPLC_{Y+1}$ attributable to the delivery class applicable to such customer or (ii) the average $CPLC_{Y+1}$ attributable to the delivery class applicable to such customer scaled to reflect the amount of electricity delivered to such customer. Delivery classes are as described in the General Terms and Conditions of ComEd's Schedule of Rates filed with the Illinois Commerce Commission (Ill. C.C. No. 10). For purposes of this Attachment M-2 (ComEd), load attributable to net metering and community supply projects may reflect both consumption and generation in the CPLC, and therefore can result in a positive or negative value for any such individual customer's calculation.

Section 4 DETERMINATION OF THE NETWORK SERVICE PEAK LOAD CONTRIBUTION

A customer's Network Service Peak Load Contribution (NSPLC) for Year Y+1 is determined in accordance with the following equation:

$$NSPLC_{Y+1} = ACustPL_Y \times \frac{ComEdPL_Y}{\sum_{Ac} ACustPL_Y}$$

Where:

$NSPLC_{Y+1}$ = Network Service Peak Load Contribution for the customer, in kW, applicable for the period beginning with January in Year Y+1 and extending through December in Year Y+1.

$ComEdPL_Y$ = ComEd Peak Load for Year Y, in kW.

$\sum_{Ac}$ = Summation over all customers.

Notwithstanding the previous provisions describing the determination of the $NSPLC_{Y+1}$, for certain situations ComEd determines a customer's $NSPLC_{Y+1}$ to be equal to (i) the average $NSPLC_{Y+1}$ attributable to the delivery class applicable to such customer or (ii) the average $NSPLC_{Y+1}$ attributable to the delivery class applicable to such customer scaled to reflect the amount of electricity delivered to such customer. For purposes of this Attachment M-2 (ComEd), load attributable to net metering and community supply projects may reflect both consumption and generation in the NSPLC, and therefore can result in a positive or negative value for any such individual customer's calculation.

II. DAILY CAPACITY PEAK LOAD OBLIGATION AND DAILY NETWORK

SERVICE PEAK LOAD OBLIGATION

Section 1 PURPOSE

The purpose of Part II is to describe the methodology used to calculate the Daily Capacity Peak Load Obligation (DCPLO) and Daily Network Service Peak Load Obligation (DNSPLO) for Load Serving Entities (LSEs) in the ComEd Zone.

Section 2 DETERMINATION OF THE DAILY CAPACITY PEAK LOAD OBLIGATION

The Daily Capacity Peak Load Obligation (DCPLO) for a LSE in the ComEd Zone taking service under Attachment F to the PJM Tariff, but not ComEd as the EDC for the ComEd Zone, ("Attachment F LSEs in the ComEd Zone") is determined in accordance with the following equation:

$$DCPLO_{LSE} = \sum_{LSEc} CPLC$$

The DCPLO for all other LSEs in the ComEd Zone, including ComEd as the EDC for the ComEd Zone, ("Attachment F-1 LSEs in the ComEd Zone") is determined in accordance with the following equation:

:

$$DCPLO_{LSE} = \sum_{LSEc} CPLC + \left(ComEdNPL_{Y} - \sum_{Ac} CPLC\right) \times \frac{\sum_{LSEc} CPLC}{\left(\sum_{Ac} CPLC - \sum_{Am} CPLC\right)}$$

Where:

$DCPLO_{LSE}$	=	Daily Capacity Peak Load Obligation for a LSE
CPLC	=	Capacity Peak Load Contribution for a customer
$ComEdNPL_{Y}$	=	ComEd Weather Normalized Peak Load for Year Y, in kW
$\sum_{Ac}$	=	Summation over all customers
$\sum_{LSEc}$	=	Summation over all customers of a LSE
$\sum_{Am}$	=	Summation over all Wholesale Municipalities

Section 3 DETERMINATION OF DAILY NETWORK SERVICE PEAK LOAD OBLIGATION

The Daily Network Service Peak Load Obligation (DNSPLO) for Attachment F LSEs in

the ComEd Zone is determined in accordance with the following equation:

$$DNSPLO_{LSE} = \sum_{LSEc} NSPLC$$

The DNSPLO for Attachment F-1 LSEs in the ComEd Zone, is determined in accordance with the following equation:
:

$$DNSPLO_{LSE} = \sum_{LSEc} NSPLC + \left(ComEdPL_Y - \sum_{Ac} NSPLC\right) \times \frac{\sum_{LSEc} NSPLC}{\left(\sum_{Ac} NSPLC - \sum_{Am} NSPLC\right)}$$

Where:

$DNSPLO_{LSE}$	=	Daily Network Service Peak Load Obligation for a LSE
NSPLC	=	Network Service Peak Load Contribution for a customer
ComEd PL_Y	=	ComEd Peak Load for Year Y, in kW
$\sum_{Ac}$	=	Summation over all customers
$\sum_{LSEc}$	=	Summation over all customers of a LSE
$\sum_{Am}$	=	Summation over all Wholesale Municipalities

III. FINAL HOURLY LOAD OBLIGATIONS

Section 1 PURPOSE

The purpose of Part III is to describe the methodology used to calculate the Final Hourly Load Obligation for Load Serving Entities (LSEs) in the ComEd Zone.

Section 2 DETERMINING FINAL HOURLY LOAD OBLIGATION

ComEd, on a monthly basis, will perform a load reconciliation to determine the difference between the Scheduled Hourly Load Obligation and the Final Hourly Load Obligation for LSEs in the ComEd Zone. The results of the reconciliation will be reported to PJM Interconnection, LLC ("PJM") for billing and settlement purposes.

Hourly Loads for customers shall be determined using customer meter data, adjusted for applicable distribution and transmission losses. In the event customer meter data is not available, customer Hourly Loads may be estimated.

The Final Hourly Load Obligation (FHLO) for an Attachment F LSEs in the ComEd Zone is determined in accordance with the following equation:

$$FHLO_{LSE} = \sum_{LSEc} HL$$

The FHLO for an Attachment F-1 LSE in the ComEd Zone, is determined in accordance with the following equation:
:

$$FHLO_{LSE} = \sum_{LSEc} HL + \left(ZL - \sum_{Ac} HL\right) \times \frac{\sum_{LSEc} HL}{\left(\sum_{Ac} HL - \sum_{Am} HL\right)}$$

Where:

FHLO$_{LSE}$ = Final Hourly Load Obligation for a LSE

HL = Hourly Load for a customer, adjusted to include applicable distribution and transmission losses

ZL = ComEd Zone Load

$\sum_{Ac}$ = Summation over all customers

$\sum_{LSEc}$ = Summation over all customers of a LSE

$\sum_{Am}$ = Summation over all Wholesale Municipalities

If adjustments are made to the Hourly Load of an Attachment F-1 LSE in the ComEd Zone after the load reconciliation, ComEd may calculate the financial value of the adjustment and report that value to PJM. ComEd will also allocate the equal and opposite financial value to all Attachment F-1 LSEs in the ComEd Zone, on a load-ratio-share basis, and report the adjustments to PJM. PJM will include any adjustments in the next monthly billing statement issued by PJM to the affected LSE(s).

IV. Administrative Provisions for Retail Electric Service

The terms and conditions included in this Attachment M-2, Section IV are available only for such service in the ComEd Zone, and are not available under this RTO Tariff for any transmission service outside of the ComEd Zone. The rates, terms and conditions of the Transmission Provider's Open Access Transmission Tariff apply to the Illinois Retail Access Program except as amended below.

A Retail Electric Supplier (RES) is any Alternative Retail Supplier (ARES) under Section 16-102 of the Illinois Public Utilities Act, 220 ILCS 5/16-102 or any Illinois Electric Utility as defined in Section 16-102 of the Illinois Public Utilities Act, 220 ILCS 5/16-102 and, by reference, Section 3-105 of the Illinois Public Utilities Act, 220 ILCS

5/3-105 (or any agent of any such electric utility to the extent the electric utility provides tariff services to retail customers through that agent) A utility that is not an Illinois Electric Utility as defined above is not a RES unless it qualifies as an ARES, in accordance with Illinois law, rules and regulations.

RES De-certification: In the event that the State of Illinois de-certifies a Transmission Customer who is not a retail customer under Section 1.11(ii) of the PJM Tariff, then Transmission Provider may immediately terminate Transmission Service to the de-certified Transmission Customer for the load of the retail customers supplied by such Transmission Customer, provided that Transmission Owner's retail service tariffs subject to the jurisdiction of the State of Illinois provide for continuation of service to affected retail customers as described in Section 1.11(ii) of the PJM Tariff by another supplier that is a Transmission Customer.

In the event of a de-certification, and/or upon receipt of notification from PJM that a RES is in default under PJM Tariff Section 7.3, ComEd, as EDC of the ComEd zone, will immediately assume wholesale supply obligations consistent with the terms of the ICC-approved rate schedules.

Term of Network Integration Transmission Service: The minimum term for Network Integration Transmission Service is one year or for any shorter period necessary to accommodate retail access under Illinois law.

Commencement of Service: Service under a Service Agreement for Point-to-Point Transmission Service or under a Network Service Agreement shall not commence until customer qualifies as a Transmission Customer under Transmission Provider's OATT.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served by electronic mail a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 24th day of June 2022.

/s/ *Lisa B. Luftig*
Lisa B. Luftig
Exelon Corporation

FERC rendition of the electronically filed tariff records in Docket No. ER22-01520-001
Filing Data:
CID: C000030
Filing Title: Commonwealth Edison submits response to May 26 Deficiency Notice
Company Filing Identifier: 8270
Type of Filing Code: 180
Associated Filing Identifier: 8134
Tariff Title: Intra-PJM Tariffs
Tariff ID: 23
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
OATT ATT M-2 (ComEd), OATT ATTACHMENT M-2 (ComEd), 3.1.0, A
Record Narative Name: OATT Attachment M-2 (ComEd)Determination of Capacity Peak Load Contributions and Network Service Peak Load Contributions
Tariff Record ID: 1501
Tariff Record Collation Value: 426843837 Tariff Record Parent Identifier: 357
Proposed Date: 2022-09-01
Priority Order: 600
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT M-2 (ComEd)

Determination of Capacity Peak Load Contributions, Network Service Peak Load Contributions, Daily Peak Load Obligation , Daily Network Service Peak Load Obligation, and Hourly Load Obligations

I. CAPACITY AND NETWORK SERVICE PEAK LOAD CONTRIBUTIONS

Section 1 PURPOSE

The purpose of Part I. is to describe the methodology used to determine capacity and network service peak load contributions for electric power and energy attributable to customers located in the ComEd Zone.

Section 2 DEFINITIONS

The following definitions are for use in this Attachment M-2. Capitalized terms used and not defined in this Attachment M-2 but defined in other provisions of the PJM OATT have the meaning given them under those provisions. Capitalized terms used in this Attachment M-2 that are not defined in it or elsewhere in the PJM OATT have the meanings customarily attributed to such terms by the electric utility industry in PJM.

a) **Average ComEd Coincident Peak Load:** the average of the sum of the (i) five (5) ComEd Zonal Loads established during the PJM Five Peaks in a summer and (ii) the corresponding Load Drop Estimates for such PJM Five Peaks.

b) **Average ComEd Peak Load:** the average of the five (5) ComEd Zonal Loads established during the ComEd Five Peaks in a summer.

c) **Average Customer Coincident Peak Load:** the average of the sum of the (i)

five (5) customer loads established during the PJM Five Peaks in a summer and (ii) the corresponding Load Drop Estimates for such customer, with such sum adjusted to include applicable distribution and transmission system losses.

d) **Average Customer Peak Load:** the average of the five (5) loads established by the customer during the ComEd Five Peaks in a summer, with such loads adjusted to include applicable distribution and transmission system losses.

e) **ComEd Five Peaks:** the five hours occurring on different calendar days in a summer during which the electric system served by ComEd experiences its five highest daily summer demands.

f) **ComEd Weather Normalized Peak Load:** the expected ComEd Zonal Load at the time of the PJM system peak load in a summer under normal weather conditions as determined by PJM.

g) **ComEd Peak Load:** the highest ComEd Zonal Load established for PJM network service in a summer.

h) **ComEd Zonal Load:** the demand for electricity placed upon the interconnected electricity system operated by PJM that is attributable to customers located in the ComEd Zone.

i) **Load Drop Estimate:** the kilowatt (kW) value attributable to curtailed demand as determined by PJM.

j) **PJM Five Peaks:** the five hours occurring on different calendar days in a summer during which the electric system served by PJM experiences its five highest daily summer demands.

k) **Summer:** the period beginning June 1 and extending through September 30 in a calendar year.

Section 3 DETERMINATION OF THE CAPACITY PEAK LOAD CONTRIBUTION

If a customer's Average Customer Coincident Peak Load for Year Y is greater than or equal to such customer's Average Customer Peak Load for Year Y, then such customer's capacity peak load contribution (CPLC) for year Y+1 is equal to such customer's Average Customer Coincident Peak Load for Year Y.

If a customer's Average Customer Coincident Peak Load for Year Y is less than such customer's Average Customer Peak Load for Year Y, then such customer's CPLC for year Y+1 is determined in accordance with the following equation:

$$CPLC_{Y+1} = ACustCPL_Y + \left(ComEdNPL_Y - AComEdCPL_Y\right) \times \frac{ACustPL_Y - ACustCPL_Y}{\sum_{5Pc}\left(ACustPL_Y - ACustCPL_Y\right)}$$

Where:

$CPLC_{Y+1}$ = Capacity Peak Load Contribution for the customer, in kW, applicable for the period beginning with June in Year Y+1 and extending through May in Year Y+2.

$ACustCPL_Y$ = Average Customer Coincident Peak Load for the customer for Year Y, in kW.

$ACustPL_Y$ = Average Customer Peak Load for the customer for Year Y, in kW.

$ComEdNPL_Y$ = ComEd Weather Normalized Peak Load for Year Y, in kW.

$AComEdCPL_Y$ = Average ComEd Coincident Peak Load for Year Y, in kW.

$\sum_{5Pc}$ = Summation over all customers for which the Average Customer Coincident Peak Load for Year Y is less than the Average Customer Peak Load for Year Y.

Notwithstanding the previous provisions describing the determination of the $CPLC_{Y+1}$, for certain situations ComEd determines a customer's $CPLC_{Y+1}$ to be equal to (i) the average $CPLC_{Y+1}$ attributable to the delivery class applicable to such customer or (ii) the average $CPLC_{Y+1}$ attributable to the delivery class applicable to such customer scaled to reflect the amount of electricity delivered to such customer. Delivery classes are as described in the General Terms and Conditions of ComEd's Schedule of Rates filed with the Illinois Commerce Commission (Ill. C.C. No. 10). For purposes of this Attachment M-2 (ComEd), load attributable to net metering and community supply projects may reflect both consumption and generation in the CPLC, and therefore can result in a positive or negative value for any such individual customer's calculation.

Section 4 DETERMINATION OF THE NETWORK SERVICE PEAK LOAD CONTRIBUTION

A customer's Network Service Peak Load Contribution (NSPLC) for Year Y+1 is determined in accordance with the following equation:

$$NSPLC_{Y+1} = ACustPL_Y \times \frac{ComEdPL_Y}{\sum_{Ac} ACustPL_Y}$$

Where:

$NSPLC_{Y+1}$ = Network Service Peak Load Contribution for the customer, in kW, applicable for the period beginning with January in Year Y+1 and extending through December in Year Y+1.

$ComEdPL_Y$ = ComEd Peak Load for Year Y, in kW.

$\sum_{Ac}$ = Summation over all customers.

Notwithstanding the previous provisions describing the determination of the $NSPLC_{Y+1}$, for certain situations ComEd determines a customer's $NSPLC_{Y+1}$ to be equal to (i) the average $NSPLC_{Y+1}$ attributable to the delivery class applicable to such customer or (ii) the average $NSPLC_{Y+1}$ attributable to the delivery class applicable to such customer scaled to reflect the amount of electricity delivered to such customer. For purposes of this Attachment M-2 (ComEd), load attributable to net metering and community supply projects may reflect both consumption and generation in the NSPLC, and therefore can result in a positive or negative value for any such individual customer's calculation.

II. DAILY CAPACITY PEAK LOAD OBLIGATION AND DAILY NETWORK SERVICE PEAK LOAD OBLIGATION

Section 1 PURPOSE

The purpose of Part II is to describe the methodology used to calculate the Daily Capacity Peak Load Obligation (DCPLO) and Daily Network Service Peak Load Obligation (DNSPLO) for Load Serving Entities (LSEs) in the ComEd Zone.

Section 2 DETERMINATION OF THE DAILY CAPACITY PEAK LOAD OBLIGATION

The Daily Capacity Peak Load Obligation (DCPLO) for a LSE in the ComEd Zone taking service under Attachment F to the PJM Tariff, but not ComEd as the EDC for the ComEd Zone, ("Attachment F LSEs in the ComEd Zone") is determined in accordance with the following equation:

$$DCPLO_{LSE} = \sum_{LSEc} CPLC$$

The DCPLO for all other LSEs in the ComEd Zone, including ComEd as the EDC for the ComEd Zone, ("Attachment F-1 LSEs in the ComEd Zone") is determined in accordance with the following equation:

:

$$DCPLO_{LSE} = \sum_{LSEc} CPLC + \left(ComEdNPL_Y - \sum_{Ac} CPLC\right) \times \frac{\sum_{LSEc} CPLC}{\left(\sum_{Ac} CPLC - \sum_{Am} CPLC\right)}$$

Where:

$DCPLO_{LSE}$ = Daily Capacity Peak Load Obligation for a LSE

CPLC = Capacity Peak Load Contribution for a customer

$ComEdNPL_Y$ = ComEd Weather Normalized Peak Load for Year Y, in kW

$\sum_{Ac}$ = Summation over all customers

$\sum_{LSEc}$ = Summation over all customers of a LSE

$\sum_{Am}$ = Summation over all Wholesale Municipalities

Section 3 DETERMINATION OF DAILY NETWORK SERVICE PEAK LOAD OBLIGATION

The Daily Network Service Peak Load Obligation (DNSPLO) for Attachment F LSEs in the ComEd Zone is determined in accordance with the following equation:

$$DNSPLO_{LSE} = \sum_{LSEc} NSPLC$$

The DNSPLO for Attachment F-1 LSEs in the ComEd Zone, is determined in accordance with the following equation:

:

$$DNSPLO_{LSE} = \sum_{LSEc} NSPLC + \left(ComEdPL_Y - \sum_{Ac} NSPLC\right) \times \frac{\sum_{LSEc} NSPLC}{\left(\sum_{Ac} NSPLC - \sum_{Am} NSPLC\right)}$$

Where:

$DNSPLO_{LSE}$ = Daily Network Service Peak Load Obligation for a LSE

NSPLC = Network Service Peak Load Contribution for a customer

$ComEd\ PL_Y$ = ComEd Peak Load for Year Y, in kW

$\sum_{Ac}$ = Summation over all customers

$\sum_{LSEc}$ = Summation over all customers of a LSE

$\sum_{Am}$ = Summation over all Wholesale Municipalities

III. FINAL HOURLY LOAD OBLIGATIONS

Section 1 PURPOSE

The purpose of Part III is to describe the methodology used to calculate the Final Hourly Load Obligation for Load Serving Entities (LSEs) in the ComEd Zone.

Section 2 DETERMINING FINAL HOURLY LOAD OBLIGATION

ComEd, on a monthly basis, will perform a load reconciliation to determine the difference between the Scheduled Hourly Load Obligation and the Final Hourly Load Obligation for LSEs in the ComEd Zone. The results of the reconciliation will be reported to PJM Interconnection, LLC ("PJM") for billing and settlement purposes.

Hourly Loads for customers shall be determined using customer meter data, adjusted for applicable distribution and transmission losses. In the event customer meter data is not available, customer Hourly Loads may be estimated.

The Final Hourly Load Obligation (FHLO) for an Attachment F LSEs in the ComEd Zone is determined in accordance with the following equation:

$$FHLO_{LSE} = \sum_{LSEc} HL$$

The FHLO for an Attachment F-1 LSE in the ComEd Zone, is determined in accordance with the following equation:

:

$$FHLO_{LSE} = \sum_{LSEc} HL + \left(ZL - \sum_{Ac} HL\right) \times \frac{\sum_{LSEc} HL}{\left(\sum_{Ac} HL - \sum_{Am} HL\right)}$$

Where:

$FHLO_{LSE}$ = Final Hourly Load Obligation for a LSE

HL = Hourly Load for a customer, adjusted to include applicable distribution and transmission losses

ZL = ComEd Zone Load

$\sum_{Ac}$ = Summation over all customers

$\sum_{LSEc}$ = Summation over all customers of a LSE

$\sum_{Am}$ = Summation over all Wholesale Municipalities

If adjustments are made to the Hourly Load of an Attachment F-1 LSE in the ComEd Zone after the load reconciliation, ComEd may calculate the financial value of the adjustment and report that value to PJM. ComEd will also allocate the equal and opposite financial value to all Attachment F-1 LSEs in the ComEd Zone, on a load-ratio-share basis, and report the adjustments to PJM. PJM will include any adjustments in the next monthly billing statement issued by PJM to the affected LSE(s).

IV. Administrative Provisions for Retail Electric Service

The terms and conditions included in this Attachment M-2, Section IV are available only for such service in the ComEd Zone, and are not available under this RTO Tariff for any transmission service outside of the ComEd Zone. The rates, terms and conditions of the Transmission Provider's Open Access Transmission Tariff apply to the Illinois Retail Access Program except as amended below.

A Retail Electric Supplier (RES) is any Alternative Retail Supplier (ARES) under Section 16-102 of the Illinois Public Utilities Act, 220 ILCS 5/16-102 or any Illinois Electric Utility as defined in Section 16-102 of the Illinois Public Utilities Act, 220 ILCS 5/16-102 and, by reference, Section 3-105 of the Illinois Public Utilities Act, 220 ILCS 5/3-105 (or any agent of any such electric utility to the extent the electric utility provides tariff services to retail customers through that agent) A utility that is not an Illinois Electric Utility as defined above is not a RES unless it qualifies as an ARES, in accordance with Illinois law, rules and regulations.

RES De-certification: In the event that the State of Illinois de-certifies a Transmission Customer who is not a retail customer under Section 1.11(ii) of the PJM Tariff, then Transmission Provider may immediately terminate Transmission Service to the de-certified Transmission Customer for the load of the retail customers supplied by such Transmission Customer, provided that Transmission Owner's retail service tariffs subject to the jurisdiction of the State of Illinois provide for continuation of service to affected retail customers as described in Section 1.11(ii) of the PJM Tariff by another supplier that is a Transmission Customer.

In the event of a de-certification, and/or upon receipt of notification from PJM that a RES is in default under PJM Tariff Section 7.3, ComEd, as EDC of the ComEd zone, will immediately assume wholesale supply obligations consistent with the terms of the ICC-approved rate schedules.

Term of Network Integration Transmission Service: The minimum term for Network Integration Transmission Service is one year or for any shorter period necessary to accommodate retail access under Illinois law.

Commencement of Service: Service under a Service Agreement for Point-to-Point Transmission Service or under a Network Service Agreement shall not commence until customer qualifies as a Transmission Customer under Transmission Provider's OATT.

Document Content(s)

Transmittal Letter.pdf.....1
Exhibit 1(b).pdf.....8
Exhibit 2(b)(i).pdf.....10
Exhibit 2(b)(ii).pdf.....12
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FERC GENERATED TARIFF FILING.rtf.....31

JRB
EXHIBIT-7

PJM Actuals: 12/01/24 - 05/31/25 (Period of PJM actuals)
Calculated RTP: June 2025

Line #	Description of Component	MG3	Source	
	Generation			
1	LMP / kWh	$ 0.03803	PJM Website - Hourly LMP - Daily	Average of the daily LMP over the previous 6 months (Dec - May for the June calculation & Jun - Nov for the December calculation)
2	HP Adder	0.00433	GSC-2 Jun24-May25 Filing	Schedule A -Line 12 - Components by kWh for PTC column
3	E-factor	(0.00261)	GSC-2 Jun24-May25 Filing	Schedule A (Line 6/Line 8) - NOTE: negative if overcollected
4	Admin	0.00012	GSC-2 Jun24-May25 Filing	Total of Line 2 - Total Administrative Charges/Line 8 - Projected Total Retail kWh Sales to Customer
5	Total	$ 0.03987	*Calculation*	Sum of four lines above (Line 1 to Line 4)
	Transmission			
6	kWh charge	$ 0.02988	TSC Dec24-May25 Interim Filing	Schedule A - Line 13 (Energy Rate w/GRT)
7	kW charge		N/A for MG3	N/A for MG3
8	kW estimate		N/A for MG3	N/A for MG3
9	kWh Estimate		N/A for MG3	N/A for MG3
10	kWh rate	$ 0.02988	TSC Dec24-May25 Filing	Energy Rate w/GRT (Line 6)
11	Total kWh	$ 0.06975	*Calculation*	Total Generation plus Total kWh rate (Line 5 +Line 10)

The total kWh cashout value is the sum of the generation and transmission components.

The generation component is the sum of the PJM Locational Marginal Price (LMP) for the prior six month period and the HP Adder, E-factor, and Admin value from the GSC-2 filing in effect during the prior six month period. The sources of those values are outlined in the GSC-2 filing.

For the MG-3 rate class, the transmission component is the kWh charge from the TSC filing in effect during the prior six month period.

MG-3 is PPL Electric's internal billing code for GS-3 customers with a peak demand geater than 100 kW.

JRB
EXHIBIT-8

State	Transition Year	Legacy Period Duration	Legacy Eligibility Deadline	Legacy Rights Origin
AR	2023 (later voided by new legislation)	20 years from date of Phase 3 Order (June 1, 2020)	Applies to customers submitting a signed Standard Interconnection Agreement to the utility by December 31, 2022	Regulatory Decision
AZ	2017, or in rate case order issued thereafter	20 years from date of interconnection	Effective date of rate case decision establishing the applicable RCP rate (August 17, 2017 for APS)	Regulatory Decision
CA	2017, or when utility reached 5.0% cap, for moving from "NEM 1.0" to "NEM 2.0"	20 years from interconnection year	Interconnection before July 1, 2017, or date when utility cap reached, whichever comes first	Regulatory Decision
CT	2022	20 years (expires December 31, 2041)	December 31, 2021	Statutory
GA	2021 (when cap was hit, specific date unclear)	15 years (15 years starting January 1, 2023)	During 2021 (date when cap was hit, specific date unclear)	Regulatory Decision (Settlement)
HI	2015	Indefinite (lifetime of system)	October 12, 2015	Regulatory Decision
IA	Utilities may propose changes after July 1, 2027, or when the NEM cap is reached	20 years	Iowa Utilities Board Order adopting changes to compensation rate	Statutory
ID	2024 (Idaho Power)	25 years (through 2045 starting in December 2019)	December 21, 2019	Regulatory Decision
IL	2025	Indefinite (lifetime of system)	January 1, 2025	Statutory
IN	July 2022 at the latest	Up to 15-30 years (expires July 1, 2047 for all NEM customers enrolled by December 31, 2017; expires July 1, 2032 for NEM	System operating before July 1, 2022 (or earlier for utilities reaching net metering cap)	Statutory

		customers enrolled after 2017 through July 1, 2022)		
KS	Post-July 2014 NEM customers can be subjected to additional charges or alternative rate designs	15 years (Pre-July 2014 customers have a Legacy period through 2029 against reduced rate for monthly excess and additional charges)	System operating prior to July 1, 2014	Statutory
KY	Varies by utility, first starting in 2021	25 years	Date of PSC Order approving changes in utility rate case to NEM or rate design	Statutory
LA	2020	15 years (expires December 31, 2034)	Interconnection application and installation completed by December 31, 2019	Regulatory Decision
MA	2016	25 years (from date of interconnection)	September 26, 2016 (application deadline for cap allocation)	Statutory
MI	Varies by utility first starting in 2017	10 years from date of enrollment	Based on final order date in utility's rate case establishing NEM successor tariff	Statutory
NH	2017	At least 23 years (expires December 31, 2040)	June 23, 2017	Statutory
NV	2016 (later voided by statutory change, re-instating NEM)	20 years	February 28, 2017	Regulatory Decision
NY	2022	Indefinite (lifetime of system)	January 1, 2022	Regulatory Decision
SC	2021	Up to 10 years (Expires May 31, 2029 for all customers that enroll after May 16, 2019 through May 31, 2021; if enrolled before May 16,	Interconnection application filed on or before May 31, 2021	Statutory

		2019, expires December 31, 2025)		
UT	2017	18 years (expires in 2035)	September 29, 2017	Regulatory Decision (Settlement)
VA	TBD (may vary by utility but transition subject to Commission discretion)	Indefinite (lifetime of system)	TBD (if any changes are authorized by the Commission)	Statutory
WA	TBD (earlier of June 30, 2029 or when cap is met)	Indefinite (lifetime of system)	TBD (earlier of June 30, 2029 or when cap is met)	Statutory
WV	Varies by utility, first approved in 2024	25 years (25 years starting January 1, 2025)	Varies by utility (roughly 8 months after Commission decision)	Regulatory Decision (Settlement, but modified by the Commission)

JRB
EXHIBIT-9

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 7, 2025
Docket No. R-2025-3057164

JSA I-23

Refer to Direct Testimony of Andrew Castanaro, PPL St. No. 15, at 5:28-6:1, which states, "PPL Electric is projecting a substantial increase in the number of customer-generators participating in net metering who do not have independent load to offset their electric usage."

a. Define and explain the phrase "substantial increase" as used in the testimony cited above. Provide all Documents utilized and/or relied upon in your answer.

b. Identify, describe and quantify PPL's projection of increased net metering customer-generators and the assumptions used in developing this projection. Provide all Documents utilized and/or relied upon in your answer.

c. Identify, describe and provide a list of all entities developing NEM systems PPL has talked to or surveyed in an attempt to understand rates of project failure based on permitting, interconnection and new federal tax policy changes. Provide all Documents utilized and/or relied upon in your answer.

d. Identify, describe and explain how PPL has utilized any information received from entities described in 23(c) has been used and/or accounted for in PPL's projections related to NEM systems. Provide all Documents utilized and/or relied upon in your answer.

e. Provide the number and nameplate capacity of each NEM facility larger than 2 MW without substantial on-site load that is currently online and operational within PPL's service territory. Provide all Documents utilized and/or relied upon in your answer.

PPL Electric Response

a) “Substantial increase” reflects the increase of no-load DER interconnections from receiving 42 applications in 2022 to receiving 437 in 2025 as of November 12, 2025, or a 940% increase in applications. See JSA I-23 Attachment 1, Tab 1.

b) See response to JSA I-26, Part (i).

c) PPL Electric has not conducted formal surveys of developers to determine why they cancel NEM applications and/or projects. Instead, PPL Electric relies on internal data regarding cancellation rates and has not gathered information from external sources.

d) See Part (c) above.

e) PPL Electric has 6 NEM facilities larger than 2 MW without substantial on-site load that are currently online totaling 15.675 MW. See JSA I-23 Attachment 1, Tab 2. There are 596 pending no-load net metering (NEM) applications of 2 MW or greater in the interconnection process, totaling 1,552 MW.

Year	2020	2021	2022	2023	2024	2025	Total
Annual Cancellation Rate	0.00%	0.00%	59.52%	48.53%	33.97%	18.54%	32.38%
Application Count	0	2	42	272	365	437	1118
Percent Growth from 2021	-	0%	2000%	13500%	18150%	21750%	-
Percent Growth from 2022	-	-	0%	548%	769%	940%	-

NOTE: 2025 is YTD and does not forecast remaining potential applications

JRB
EXHIBIT-10

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set IV Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 26, 2025
Docket No. R-2025-3057164

JSA IV-2

Refer to the Secretarial Letter dated July 17, 2025 in Docket No. P-2024-3047290 related to the results of PPL's July 2025 AEC solicitations.

a. What was the average price of the long-term AEC bids that were rejected by the Commission because they were higher than futures market prices?
b. What were the futures market prices used in this price comparison?
c. Please provide estimates of the number of AECs that the Company expects to need to acquire in order to meet the Tier 1 and solar carve-out AEPS compliance obligations each year from Compliance Year 2026 to Compliance Year 2030.
d. Please provide estimates of the number of Tier 1 and solar AECs that the Company already has contracted for each Compliance Year from Compliance Year 2026 to Compliance Year 2030.
e. Provide all Documents used, relied upon and/or that support each answer in subparts (a)-(d) above.

PPL Electric Response

a. See results of the RFP at the following link: https://ppldsp.com/long-term-pa-solar-aec-rfp/rfp-results/?
b. The PA PUC made the determination using their own analysis. The Company is unaware of what market prices the PA PUC used in performing its analysis.
c. PPL Electric does not project the number of AECs needed to meet its AEPS Act compliance obligations associated with its load following contracts. Per the Company's DSP VI plan, AECs are included in supplier obligations as part of the full-requirements load following contracts. The Company does need to procure AECs for its 10-year, Long-Term Block product that serves Residential customers. It is estimated that the Company will need annually approximately 7,000 Tier I Solar

AECs, 100,000 Tier I Non-Solar AECs, and 103,000 Tier II AECs associated with the Long-Term Block product.

d. See response to Part c.
e. See response to Part a. and the documents submitted in the DSP VI proceeding at Docket P-2024-3047290.

JRB
EXHIBIT-11

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set IV Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 26, 2025
Docket No. R-2025-3057164

JSA IV-2

Refer to the Secretarial Letter dated July 17, 2025 in Docket No. P-2024-3047290 related to the results of PPL's July 2025 AEC solicitations.

a. What was the average price of the long-term AEC bids that were rejected by the Commission because they were higher than futures market prices?
b. What were the futures market prices used in this price comparison?
c. Please provide estimates of the number of AECs that the Company expects to need to acquire in order to meet the Tier 1 and solar carve-out AEPS compliance obligations each year from Compliance Year 2026 to Compliance Year 2030.
d. Please provide estimates of the number of Tier 1 and solar AECs that the Company already has contracted for each Compliance Year from Compliance Year 2026 to Compliance Year 2030.
e. Provide all Documents used, relied upon and/or that support each answer in subparts (a)-(d) above.

PPL Electric Response

a. See results of the RFP at the following link: https://ppldsp.com/long-term-pa-solar-aec-rfp/rfp-results/?
b. The PA PUC made the determination using their own analysis. The Company is unaware of what market prices the PA PUC used in performing its analysis.
c. PPL Electric does not project the number of AECs needed to meet its AEPS Act compliance obligations associated with its load following contracts. Per the Company's DSP VI plan, AECs are included in supplier obligations as part of the full-requirements load following contracts. The Company does need to procure AECs for its 10-year, Long-Term Block product that serves Residential customers. It is estimated that the Company will need annually approximately 7,000 Tier I Solar

AECs, 100,000 Tier I Non-Solar AECs, and 103,000 Tier II AECs associated with the Long-Term Block product.

d. See response to Part c.
e. See response to Part a. and the documents submitted in the DSP VI proceeding at Docket P-2024-3047290.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2025-3057164
v.	:	
	:	
PPL Electric Utilities Corporation	:	
	:	

Solar Energy Industries Association and the Coalition for Community Solar Access, the "Joint Solar Advocates"

Statement No. 2-SR

Surrebuttal Testimony of Justin R. Barnes

Topics Addressed: Responses to the Rebuttal Testimony of PPL and OCA

Date: February 9, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name, position, and business address.

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 203, Cary, North Carolina, 27511. I am employed by EQ Research LLC as its President. EQ Research provides energy-related research and consulting services, which include subscription-based activity tracking services as well as customized reports, analysis, and expert testimony.

Q. On whose behalf are you submitting Surrebuttal Testimony?

A. My testimony is provided on behalf of the Solar Energy Industries Association ("SEIA")[1] and the Coalition for Community Access ("CCSA"), jointly called the Joint Solar Advocates ("JSA") in this proceeding.

Q. Are you the same Justin Barnes that filed Direct Testimony in this case on December 22, 2025?

A. Yes.

Q. What is the purpose of your Surrebuttal Testimony?

A. My surrebuttal testimony primarily responds to the Rebuttal Testimony of Andrew Castanaro[2] ("Castanaro Rebuttal") on behalf of PPL Electric ("PPL" or "the Company") regarding his support for the Company's Maximum Registered Peak Load ("MRPL") proposal. I also briefly respond to the Rebuttal Testimony of Zachary F. Teti[3] ("Teti Rebuttal") on behalf of the Office of Consumer Advocate ("OCA") regarding his concern

[1] Capitalized terms used in this Surrebuttal Testimony that are not otherwise defined shall have the meanings specific in my earlier Direct Testimony, JSA Statement No. 2.
[2] Rebuttal Testimony of Andrew Castanaro on Behalf of PPL Electric Utilities Corporation, PPL Statement No. 15-R, January 23, 2026. ("Castanaro Rebuttal")
[3] Testimony of Zach Teti on Behalf of The Pennsylvania Office Of Consumer Advocate, OCA Statement No. 6-R, January 23, 2026. ("Teti Rebuttal")

about how my proposal to allow customers to register negative peak load contributions ("PLCs") could affect Generation Service Charge 1 ("GSC-1") customers. My response to Witness Teti is limited to clarifying that his apparent concern is unfounded, though well-intentioned.

Q. Please summarize your areas of disagreement with Witness Castanaro and his continued support of the Company's MRPL proposal.

A. I take issue with several aspects of Witness Castanaro's Rebuttal Testimony.

First, I object to his attempt to now characterize PPL's MRPL proposal as addressing the proper default service classification of net metering customer-generators rather than the relative value and costs of customer-generator excess generation and how, if at all, it impacts default service rates for GSC-1 customers. It is quite clear from both Mr. Castanaro's Direct and Rebuttal Testimony and the testimonies of numerous other supporters of the Company's MRPL proposal, that the matter of value/costs and potential subsidization by certain GSC-1 customers of PPL's cash-out payments to customer-generators for their excess generation is the central concern. In my Direct Testimony, I presented a conciliatory and balanced solution (the "JSA Proposal") that fully addresses subsidization and GSC-1 rate impact concerns through a series of targeted refinements to existing practices. Witness Castanaro's attempt to reframe the issue as a matter of proper customer classification is a thinly disguised attempt to avoid dealing with the merits of the JSA Proposal now that the errors and shortcomings of the MRPL proposal have been demonstrated.

Second, Witness Castanaro raises numerous objections to my proposal for allowing customer-generators to register negative PLCs in the context of both: (i) GSC-1 load

settlement, and (ii) the JSA proposal to allow negative PLCs to be used to provide value-based compensation for generation capacity under the GSC-2 rate. His objections to negative PLCs are ill-informed and supported by assertions and "beliefs" that are factually inaccurate or are irrelevant. Those misplaced objections include his dismissal of the example I provided explaining how Commonwealth Edison in Illinois ("ComEd IL") permits and utilizes negative PLCs for customer generation, and allegations that negative PLCs create market distortions and are contrary to PJM practices. In reality, allowing customer-generators to register negative PLCs alleviates market distortions produced by PPL's current practices and the ComEd IL example demonstrates precisely why such an improvement is needed and how it can be implemented.

Third, Witness Castanaro's objections to the Legacy Rights component of the JSA Proposal in which certain customer-generator projects currently under development could remain on the GSC-1 rate by, among other things, surrendering alternative energy credits ("AECs") to PPL lack merit. His objections are based on supposed implementation barriers that are either non-existent or superficial, and which arise from his apparent misunderstanding and mischaracterization of the JSA Proposal. Those misunderstandings, among others, include: (i) a suggestion that the JSA Proposal would require residential customers to subsidize GSC-1 Legacy Rights customer-generators, and (ii) that the proposal cannot be implemented due to a need to revise the Company's default service plan ("DSP").

Q. How do you respond in general to Witness Castanaro's objections to the JSA Proposal?

A. PPL's approach to the real challenges associated with the "claimed" proliferation of large customer-generators within the GSC-1 default service rate class amounts to taking a

bulldozer to a problem that merits a far more delicate and nuanced approach. It is akin to finding cracks in the foundation of a home and immediately deciding to tear it down without any consideration of the fact there are readily available fixes to such problems or the collateral damage associated with simply demolishing the structure. Witness Castanaro's approach to contesting the JSA Proposal in his Rebuttal Testimony is predicated upon specious arguments intended to show insurmountable barriers to implementing the balanced JSA Proposal that in reality do not exist. The JSA's recommended adjustments to the MRPL proposal are a sensible and prudent middle course available to PPL and the Commission that do not unduly risk either customer-generator legal rights or the future development of alternative energy, while mitigating concerns about the impacts of excess generation on GSC-1 customers. Further, PPL's refusal to recognize the benefits of customer generation, and viewing it as a harm that must be blunted, is neither in customers' nor the public's interest.

By contrast, the JSA's approach, as reflected in the JSA Proposal, is a carefully curated design that is based on fully acknowledging the present concern, identifying the root causes, and devising a practicable and balanced set of solutions reflective of resolving those root causes. Adopting the JSA Proposal would result in a far more favorable outcome by solving for PPL's concern about the upward pressure on the GSC-1 rate, while at the same time supporting Pennsylvania's mandated objective of supporting customer-generator deployment. Furthermore, the AEC transfer element of the Legacy Rights portion of the JSA Proposal would effectively source a greater portion of the AECs needed to meet Alternative Energy Portfolio Standard ("AEPS Act") requirements from PPL's territory,

concentrating the economic benefits among the same customers that pay for AEPS Act compliance costs.

Q. How is your Surrebuttal Testimony organized?

A. My Surrebuttal Testimony is organized by topic, as follows:

- Section II addresses the proper framing of the Company's MRPL proposal as a means of addressing subsidization issues and demonstrates how the JSA Proposal is specifically designed to eliminate such subsidization.
- Section III addresses the justification of allowing negative PLCs as a concept tethered in cost causation, and refutes the various arguments that Witness Castanaro makes in opposition to negative PLCs and the component of the JSA Proposal calling for the GSC-2 rate to be modified to provide a capacity credit to customer-generators that register negative PLCs. I also respond to OCA Witness Teti's concern about the impact of allowing customer-generators to register negative PLCs.
- Section IV addresses Witness Castanaro's objections to the Legacy Rights component of the JSA Proposal, including his concerns about the conceptual structure and supposed implementation complexities.

Q. Have you changed any of the recommendations you made in your Direct Testimony as a result of any other parties' testimony in this proceeding?

A. No.

II. THE OBJECTIVE OF THE MRPL PROPOSAL

Q. How does Witness Castanaro discuss the subject of the cost and value of customer-generator excess generation in his Rebuttal Testimony?

A. In general, he talks out of both sides of his mouth. On one hand, he disputes how I framed the central issue in my Direct Testimony as being improperly focused on the relative costs and benefits of excess generation produced by customer-generators, stating the Company's objective is "to maintain clean equitable standards for rate classification."[4] He makes a similar assertion responding to OCA Witness Teti stating "The Company's proposal is not about the value customer-generators add to the system, but rather the appropriate classification for providing default service to these customers."[5] These references are only a select set of examples; other instances expressing the same sentiment are present throughout his Rebuttal Testimony.

On the other hand, both his Direct Testimony and his Rebuttal Testimony extensively address the specter of claimed large increases in the GSC-1 rate brought on by the alleged proliferation of *large customer-generators* (not a term found anywhere in the AEPS Act) taking service in the GSC-1 rate class. For instance, Exhibits AC-1 through AC-3 represent scenarios of potential GSC-1 rate impacts, which JSA Witness Kevin Lucas has extensively shown to be flawed. Witness Castanaro also rebuts Walmart Witness Lyon in his Rebuttal Testimony by stating "Furthermore, the Company's analyses show that without its MRPL proposal being approved, the Small C&I PTC rate will increase significantly."[6] His Rebuttal Testimony further attempts to explain this phenomenon by discussing his view of

[4] Castanaro Rebuttal at 36:12-13.
[5] *Id.* at 4:10-12.
[6] *Id.* at 42:1-2.

how cash-outs of excess generation at the Price to Compare ("PTC") will always be at rates higher than the cost of GSC-1 default service supply because the PTC rate includes administrative costs, net metering costs, and true-ups of previous cost and revenue imbalances.[7] Again, these references are only a selection of examples.

Q. Please explain the conflict present in Witness Castanaro's description of the excess generation "problem" and the objective of the Company's claimed solution to that problem through the MRPL proposal.

A. The potential for negative GSC-1 rate impacts that he discusses at length are fundamentally driven by the costs of compensation for excess generation at the GSC-1 PTC rate (i.e., the cost rate) as compared to the value of that excess generation for reducing GSC-1 default supply costs (i.e., the value rate). The difference between those rates is what produces any GSC-1 rate impact, be it a positive or negative one. That is, if the two rates are equal, no impact would exist.

Q. What is the problem with framing the objective of the MRPL proposal as relating to proper customer classification, as Mr. Castanaro now proposes, rather than the questions of cost, value, and potential subsidization?

A. It is designed to supply a new justification for the Company's MRPL proposal based on a reason having nothing to do with the true objective and impact, which is to prevent upward pressure on the GSC-1 rate that might occur based on the status quo. By doing so, Witness Castanaro's framing of the MRPL proposal attempts to sidestep consideration of the solutions to the GSC-1 rate impact problem reflected in the JSA Proposal by deeming those solutions irrelevant. Moreover, the new PPL customer classification justification for the

[7] *Id.* at 7-8.

MRPL erroneously relies on classifying customers with small purchasing loads as customers who have large customer loads. This is inconsistent with how any other customer class is designed and a rationalization for moving small customers into a large customer default service category.

Q. Did Witness Castanaro dispute any aspects of your calculations with respect to the value of excess generation as a source of reductions in default supply costs?

A. No. He did not directly refute my estimate of how excess generation reduces GSC-1 default supply costs under current conditions (sometimes referred to as the status quo), which demonstrated that the rate associated with the reduction in default service supply costs exceeds the GSC-1 PTC rate if the value of AECs is considered (i.e., under the JSA Proposal for Legacy Rights). He also did not dispute my methodology or the results of my calculations of the wholesale value of excess generation under a scenario where negative PLCs are permitted, which also demonstrated that the value of excess generation exceeds the GSC-1 PTC if the value of AECs is considered.

Q. What should the Commission conclude from your discussion of the objective of the Company's MRPL proposal?

A. The Commission should reject Witness Castanaro's argument that the MRPL proposal relates to the question of appropriate customer classification. Witness Castanaro's assertions in this regard are merely a pretext designed to evade a thoughtful and evidence-based evaluation of the Company's case from the perspective of negative rate impacts on the GSC-1 rate class, and how the JSA Proposal is specifically designed to eliminate such negative impacts.

Q. Do you have any further responses to Witness Castanaro's characterization of the basis and motivation for the JSA's opposition to the Company's MRPL proposal?

A. Yes. In his Rebuttal Testimony, Witness Castanaro makes the following statement in reference to parties that oppose the Company's MRPL proposal: "Opponents, on the other hand, aim to maintain the status quo because it allows them to continue profiting from an inflated PTC."[8] This statement is a complete mischaracterization of the JSA's position. Rather, the JSA Proposal departs considerably from the status quo and establishes a new mechanism for protecting the interests of both: (i) GSC-1 customers, and (ii) the owners of mature, already under development customer-generator projects with considerable sunk investment costs that support the achievement of the state's renewable energy policy goals.[9] Under the JSA's proposal, those project owners would be required to make a considerable financial commitment (i.e., an enhanced interconnection cost deposit) and sacrifice future revenue (i.e., surrender AECs at no cost) in order to remain eligible for the GSC-1 rate. This arrangement is not "the status quo" by any objective interpretation.

III. ALLOWING NEGATIVE PLCS

A. Response to PPL Witness Castanaro

Q. Please summarize the arguments Witness Castanaro makes in opposition to the JSA's proposal to allow customer-generators to register a negative PLC.

A. He raises a series of objections, a number of which are centered on his view that the development and use of negative PLCs by ComEd IL is not comparable or otherwise relevant to the present circumstances. Witness Castanaro's objections are listed below:

[8] *Id.* at 9:9-10.

[9] The only portion of the JSA Proposal that contemplates the "status quo" is Legacy Rights for a small number of projects that are already operational or under construction.

- The ComEd IL example is not comparable because in Illinois the Illinois Power Agency ("IPA") procures default service supply, while in Pennsylvania PPL bears the financial and operational risks.[10]
- Negative PLCs are not used by ComEd IL for settlement purposes.[11]
- Negative PLCs in ComEd IL territory are used only to stimulate large customer renewable investments as part of a coordinated state policy.[12]
- Negative PLCs produce market distortion and are inconsistent with PJM practices.[13]

Q. How do you respond to Witness Castanaro's assertion[14] that the ComEd IL comparison is inapt due to the default service structure in Pennsylvania?

A. While it is true that the IPA procures default service supply in Illinois on behalf of ComEd IL customers, this approach is a distinction without a difference. Default service is a cost pass-through mechanism in both Illinois and Pennsylvania where customers and suppliers, rather than the procuring entity, bear the market risk. That is, neither PPL nor the IPA are exposed to market risk. Wholesale bidders to supply default service certainly bear a risk, since they commit to serving load at a price that might understate their actual costs during a future period. Customers bear a risk from the standpoint of receiving a fixed price for future supply that might be higher than actual market prices. But regardless of fluctuations in customer load or market prices, PPL and the IPA each recover their costs.

[10] Castanaro Rebuttal at 37:15 to 38:4.
[11] *Id.* at 38:18-19.
[12] *Id.* at 38:16-18.
[13] *Id.* at 38:4-15.
[14] *Id.* at 37:14-21.

Q. How do you respond to Witness Castanaro's assertion[15] that the negative PLCs are not used by ComEd IL to settle PJM capacity and transmission costs?

A. Witness Castanaro's assertion is inaccurate and incorrect. One of the primary purposes of a utility's Attachment M-2 is to define the protocols for peak load and energy obligation determinations for the purpose of market settlements. JRB Exhibit-6 of my Direct Testimony expressly articulates the logic of allowing negative PLCs for this specific purpose, i.e., ensuring that load-serving entities ("LSEs") with customers that have on-site generation or participate in community solar are assigned the peak load reductions associated with that generation as a reduction in the LSE's cost to serve them. As shown in JRB Exhibit-5 of my Direct Testimony, ComEd IL's Attachment M-2 expressly provides that negative PLCs are applied to both generation capacity and transmission capacity peak load determinations for ComEd IL customers.

Q. How do you respond to Witness Castanaro's understanding[16] that negative PLCs are used to "incentivize certain large customer renewable investments" tied to a "coordinated state policy"?

A. Witness Castanaro's understanding in this regard is inaccurate. As articulated in ComEd IL's Attachment M-2 provided as JRB Exhibit-5 of my Direct Testimony, the negative PLC construct encompasses all net metering customers and community solar facilities, not some narrow set of "large customer renewable investments." Furthermore, although it is true that ComEd IL's proposal to revise its Attachment M-2 to expressly allow negative PLCs was prompted by a legislative act, JRB Exhibit-6 of my Direct Testimony contains ComEd IL's explanation to the Federal Energy Regulatory Commission ("FERC") for the change and

[15] *Id.* at 38:18-19.
[16] *Id.*at 38:16-18.

clearly demonstrates its merits as a matter of cost causation. Among other things, ComEd IL asserted to the FERC:

> PJM's peak load forecast recognizes the value of net metering and community solar projects by reducing the peak demand forecasted for ComEd's zone. When PJM procures capacity, it does so on the basis of that reduced peak demand calculation. This peak demand reduction, and the resulting reduction in the cost of capacity procured, inures to the benefit of all customers in the ComEd zone. Nevertheless, net metering customers and community supply projects that produce more energy than they use during the five highest daily peaks may fail to receive the full value of providing that reduction because their contribution is artificially limited to zero.[17]

Furthermore, the AEPS Act is also a state policy that favors the development of renewable energy.

Q. How do you respond to Witness Castanaro's argument[18] that negative PLCs produce market distortions and are contrary to the PJM's practices?

A. To start with, a negative PLC represents an actual negative load (i.e., export to the grid) at the time of a system or zonal peak. Allowing for the registration of a PLC based on actual metered values during peak hours, whether negative or positive, is not a distortion. Rather, it remedies the market distortion that is created by the Company's current practice of assigning an artificial floor value of zero to peak loads in place of actual measured values. Furthermore, Witness Castanaro's assertion that negative PLCs are contrary to PJM practices is belied by the fact that (i) ComEd IL, one of the largest if not the largest utility member of the PJM, employs negative PLCs, and (ii) PJM's Manual 14D Appendix A, which addresses rules for behind the meter ("BTM") generation,[19] allows for BTM

[17] JRB Exhibit-6, p. 5.
[18] Castanaro Rebuttal at 38:4-12.
[19] PJM Manual 14D. December 17, 2025 Update. Available at: https://www.pjm.com/-/media/DotCom/documents/manuals/m14d.ashx Under PJM Manual 14D, all of Pennsylvania net metered projects – including those the JSA has characterized as FTM DG and BTM DG – are considered BTM generation. ComEd IL addresses this distinction in the context of community solar projects in its letter to the FERC that I provided as JEB Exhibit-6 to my Direct Testimony.

generation to be reflected as a load reduction without any zero floor value.[20] That Manual also allows for that load reduction to be subtracted from the LSE capacity obligations and incorporated into PJM transmission and resource adequacy planning models. And, to be clear, this is not only my interpretation of PJM Manual 14D. ComEd IL explained as much in its Attachment M-2 submission to the FERC included as JRB Exhibit-6 of my Direct Testimony.

Q. What should the Commission conclude regarding Witness Castanaro's opposition to the general concept of allowing customer-generators to register a negative PLC?

A. Witness Castanaro's assertions should be rejected. His arguments are based entirely on inaccuracies in his understanding of how the negative PLC construct can be - and in the case of ComEd IL is - used to reduce default service costs, PJM's rules regarding BTM generation, and the implications that negative PLCs would have for PPL as a procurement agent of default service.

Q. Please explain how the negative PLC construct relates to your recommendation for revisions to the GSC-2 tariff that would provide GSC-2 customer-generators compensation for the generation capacity benefits of excess generation.

A. As I explained in my Direct Testimony, the GSC-2 tariff charges customers for the generation capacity component of default supply service based on their PLC and the prevailing PJM capacity rate. However, the compensation rate for excess generation produced by GSC-2 customer-generators omits the generation capacity component. I recommended that the GSC-2 compensation rate for excess generation be modified to provide a capacity credit in the event that a customer registers a negative PLC. That is, any

[20] With the limitation that an LSE cannot have a negative capacity obligation, as I noted in my Direct Testimony.

capacity credit would be determined in the same manner as a capacity charge, but with the sign reversed if the customer's PLC is negative. This change would improve the alignment between the GSC-2 credit for excess generation and cost causation by making charges and credits symmetrical based on identical assessment of peak load contribution that is not distorted by an artificial minimum value of zero.

Q. How does Witness Castanaro respond to your GSC-2 capacity credit recommendation?

A. He first claims that such a capacity credit "would effectively compensate customer-generators for capacity when their capacity obligation is zero."[21] He then asserts that PLC measurements are presently only used to allocate capacity obligations to LSEs rather than calculate excess generation credits, and that implementing an equivalent credit "would misalign with cost-causation principles and introduce unnecessary complexity into billing and settlement processes."[22]

Q. What is your response to Witness Castanaro regarding the arguments against your GSC-2 capacity credit proposal?

A. The notions that a customer-generator's "capacity obligation" has a zero minimum value, and that the design is contrary to cost causation, are both products of Witness Castanaro's erroneous position that a customer cannot register a negative PLC. I have already discussed why this argument lacks merit. Turning to his assertion that PLC measurements are not used to calculate excess generation credits, his argument is circular. The omission of the generation capacity component of the GSC-2 supply rate from the GSC-2 compensation rate for excess generation is precisely the problem my recommendation is intended to

[21] Castanaro Rebuttal at 40:4-5
[22] *Id.* at 40:6-9.

solve. Using a customer's PLC, as is presently done for determining the charge for positive usage, is the most logical way to do so in the context of excess generation (i.e., negative usage).

His final argument, that my proposal would create "unnecessary complexity", is completely unsupported. I fail to see how establishing a credit that is identical to the present capacity charge except for the numerical sign is particularly complex given that PPL can accomplish this result for all other billing determinants within the PTC, and Witness Castanaro does not identify any specific reason why doing so presents a meaningful challenge.

Q. How should the Commission view Witness Castanaro's arguments against your recommendation to incorporate a capacity credit based on a negative PLC into the GSC-2 credit rate for excess generation?

A. The Commission should recognize that the Company's arguments essentially recycle their arguments in opposition to the conceptual basis for allowing negative PLCs, which I have already established are based on factual inaccuracies and therefore should be rejected.

B. Response to OCA Witness Teti

Q. Please summarize OCA Witness Teti's Rebuttal Testimony on your proposal to allow customers to register negative PLCs.

A. Witness Teti generally supported my proposal, finding it "to be equitable and more in the spirit of the AEPS Act."[23] However, he also observed that careful consideration would be needed to ensure that any customer-generators that remain on the GSC-1 rate would not

[23] Teti Rebuttal at 10:7-8.

receive double-compensation via the GSC-1 PTC rate along with compensation for registering a negative PLC.[24]

Q. How do you respond to Witness Teti's concern that allowing negative PLCs could produce double compensation for GSC-1 customer generators?

A. I appreciate and agree with the spirit of his concern. Allowing customer-generators to register negative PLCs should not be implemented in a way that creates double-compensation. However, the Commission should appreciate that no such risk actually exists under the JSA Proposal because a negative PLC would only affect excess generation compensation for customer-generators that take service under the GSC-2 rate, who do not presently receive any compensation for the generation capacity component of the default supply rate. Any customer-generator that remains on the GSC-1 rate would continue to receive the same GSC-1 PTC compensation that they do at present, which already includes the generation capacity component of the supply rate and which would not change under my proposal. The effect of the JSA's negative PLC proposal on GSC-1 customers would be limited to reducing the load obligations borne by GSC-1 wholesale default service suppliers so that their default service bids could reflect the cost savings benefits of excess generation by customer-generators as GSC-1 customers. This in turn supports least-cost procurement of default service supply.

[24] *Id.* at 10:8-10.

IV. JSA LEGACY RIGHTS PROPOSAL

Q. Please explain what you mean by the term "Legacy Rights".

A. I use the term Legacy Rights to refer to protections that allow customers to continue to take service under the terms of a previous utility rate schedule upon a prospective change to that rate schedule. In the current case, Legacy Rights denote the eligibility of current customer-generators and certain prospective customer-generators to take service under the GSC-1 rate schedule if the Company's MRPL proposal changing GSC-1 eligibility is approved.

Q. Please briefly summarize the JSA Proposal regarding Legacy Rights.

A. In brief, the JSA Proposal would allow all customer-generators with operational or under construction projects to continue to receive service under the GSC-1 rate, and permit projects under development to remain eligible for the GSC-1 rate conditioned on the project owner exercising a one-time election to both: (i) make a non-refundable deposit of 50% of the Company's estimated costs of distribution upgrades (cumulative), and (ii) transfer AECs produced by the project to PPL at no cost for the term of the legacy rights period. The conditions associated with Legacy Rights for under development customer-generator projects are intended to limit qualification to mature projects with significant sunk costs by way of the enhanced interconnection upgrade payment and use the value of transferred AECs for the benefit of GSC-1 customers to mitigate potential rate impacts. In my Direct Testimony, I used the term Existing Facilities to refer to operational or under construction projects that would be granted unconditional Legacy Rights, and the term Transition Facilities to refer to under development customer-generator projects that would be subject to the one-time election to secure Legacy Rights.

Q. Please summarize Witness Castanaro's position regarding Legacy Rights.

A. Witness Castanaro opposes the establishment of Legacy Rights in general and offers several critiques of the JSA Proposal regarding the transfer of AECs by potential Transition Facilities as a means of securing Legacy Rights. His general opposition to Legacy Rights is based on arguments that:

- Allowing Legacy Rights undermines equity and would force non-customer-generators to bear unreasonable costs;[25]
- Customer-generators could or should have anticipated the types of the changes the Company now proposes given that the Company's rates always change over time;[26] and
- The Commission did not expressly establish a Legacy Rights policy in decisions rendered on similar issues in UGI Electric's DSP V Case and Citizens Electric's 2025 rate case.[27]

With respect to the JSA Proposal specifically he raises the following concerns regarding the overall structure and implementation challenges:

- It would require residential customers to subsidize GSC-1 Legacy Rights Generators.[28]
- The need to establish a "proxy price" for surrendered AECs would require additional Commission resources.[29]
- The proposal requires revisions to the Company's DSP that cannot be accomplished in the time frame needed to implement the proposal.[30]

[25] Castanaro Rebuttal at 24:4-7.
[26] *Id.* at 24:7-10.
[27] *Id.* at 25-26.
[28] *Id.* at 28:13-17.
[29] *Id.* at 28:3-8.
[30] *Id.* at 27:17 to 28:2.

- The recommended timelines for implementing the customer-generator election are not practicable, referring to the 45-day deadline for customer-generators to make elections after receiving a notice from PPL.[31]
- Pennsylvania's net metering regulations prevent customer-generators from paying for the metering that would be necessary for measuring the production of surrendered AECs.[32]

Q. How do you respond to Witness Castanaro's arguments against Legacy Rights as a matter of general ratemaking policy?

A. Most significantly, the JSA Proposal is specifically designed to eliminate adverse rate impacts on the GSC-1 rate class, which renders his concerns regarding equity moot. With respect to his argument that prospective customer-generators could or should have known that the rules could change in a way that would considerably undermine their investments, I point to two undeniable facts. First, many of the projects that would be potentially eligible for Legacy Rights submitted interconnection applications before the first indication that rule changes could be in the offing in UGI Electric's DSP V case. Prior to that time, prospective customer-generators could not reasonably have had any way of knowing if or to what degree default service classification protocols could undermine their investments. Second, it should be obvious that they were not aware of the character or magnitude of the potential risk given the pattern and number of new interconnection requests. Third, there is a distinct difference between the type of garden-variety rate changes that occur frequently as a matter of general course and fundamental changes in rate structure, such as the Company's MRPL proposal. As I demonstrated in my Direct Testimony, the

[31] *Id.* at 27:19-21.
[32] *Id.* at 28:22 to 29:7.

establishment of Legacy Rights in the face of significant changes in net metering and distributed generation compensation policies is virtually universal in the national electric regulatory context.

Q. Please respond to Witness Castanaro's criticisms of the JSA Proposal for establishing Legacy Rights for Transition Facilities.

A. I will address each criticism in turn.

Residential Subsidization: As explained in my Direct Testimony, the use of AECs from Transition Facilities that avail themselves of Legacy Rights would reduce the volume of AECs that need to be procured from other sources on behalf of residential load. Accordingly, the JSA Proposal would result in more localized procurement of AECs at no incremental cost compared to procuring AECs through other means.

AEC Proxy Price: As I explained in my Direct Testimony, establishing the proxy price would not require any additional resources by the Commission relative to the current practice of evaluating AEC market prices to gauge the reasonableness of offers in PPL's annual AEC procurements. Developing a proxy price would simply be a different use case for the AEC market price evaluation that the Commission already performs.

Need for DSP Modifications: Witness Castanaro fails to identify any specific modifications to the Company's DSP that would be required to implement the AEC conveyance mechanism. In addition, even if the Commission were to determine that DSP modifications are required, there is ample time to do so for two reasons. First, the Transition Facilities are not yet operational so any conveyance and monetization of AECs will not even begin to occur until a future date. Second, the Company's existing tariff implementing its DSP already contains a provision allowing PPL to sell AECs and use that revenue to offset

default service supply costs.[33] That mechanism can be used for as long as is necessary if changes to the Company's DSP are determined to be necessary in order to apply Transition Facility AECs against AEPS Act compliance obligations for default service supply.

Customer-Generator Election Timeline: Witness Castanaro misunderstands the timelines for Transition Facilities elections.[34] The 45-day timeline that he references as being too short for actions required by PPL is not a timeline for PPL; it is a deadline for owners of potential Transition Facilities to make their election of whether or not to proceed with making the enhanced interconnection upgrade payment and agreeing to surrender AECs produced by the facility after PPL issues an election notice. Furthermore, if the Company believes that the process timelines are not practicable, it has the opportunity to suggest an alternative, which Witness Castanaro failed to do.

Metering Cost Responsibility: Witness Castanaro's concern regarding the responsibility for AEC metering costs is easily addressed. While it is true that the net metering regulations indicate the electric distribution company is responsible for metering costs if it desires to measure AECs conveyed by customer-generators that surrender AECs, the obvious purpose of this portion of the net metering regulations is to protect customer-generators against bearing AEC metering costs if they have no interest in dealing with AEC sales or retirements. There is no apparent bar preventing a customer-generator from voluntarily agreeing to reimburse PPL for metering costs if they wish to do so, which they may want to do in exchange for legacy rights.

[33] PPL Electric Tariff. Eighteenth Revised Page No. 19Z.4.
[34] Castanaro Rebuttal at 27:20-28:2.

Q. What should the Commission conclude regarding Witness Castanaro's criticisms of the Legacy Rights component of the JSA Proposal?

A. The Commission should first find that PPL's concerns regarding "equity" to GSC-1 customers are unfounded because the JSA Proposal is specifically designed to equalize the monetized values associated with excess generation with the costs of compensation for excess generation at the GSC-1 PTC. With this issue resolved, the Company's other arguments against the core concept of Legacy Rights are moot. Second, the Commission should conclude that PPL's criticisms of the AEC conveyance component of the Legacy Rights mechanism have no merit because those criticisms are based on a superficial analysis that misunderstands and mischaracterizes how the JSA Proposal would operate.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, but I reserve the right to file or provide such other additional testimony as many necessary or appropriate.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	
Coalition For Affordable Utility Services	
And Energy Efficiency in Pennsylvania	Docket Nos.
Office of Small Business Advocate	R-2025-3057164
Brad and Jennifer Woolley	C-2025-3057844
	C-2025-3057889
v.	C-2025-3057946
PPL Electric Utilities Corporation	

VERIFICATION

I, Justin R. Barnes, hereby declare that I am the President of EQ Research LLC; that, as such, I am authorized to make this verification on their behalf; that the facts set forth in the foregoing Surrebuttal Testimony are true and correct to the best of my knowledge, information and belief, and that I make this verification subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Date: February 9, 2026

By: _____

Justin R. Barnes, President
EQ Research LLC

WALMART STATEMENT NO. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3057164
	:	
PPL Electric Utilities Corporation	:	

REBUTTAL TESTIMONY OF

MATTHEW T. LYON

ON BEHALF OF

WALMART INC.

JANUARY 23, 2026

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I. Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Matthew T. Lyon. My business address is 814 Respect Drive, Bentonville, AR 72716. I am employed by Walmart Inc. ("Walmart") as a Senior Manager, Utility Partnerships – Regulatory.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of Walmart.

Q. ARE YOU THE SAME MATTHEW T. LYON WHO PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF WALMART?

A. Yes.

II. Purpose of Rebuttal Testimony and Summary of Recommendations

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimonies of other intervenors regarding the proposed reclassification of customer-generators based on Maximum Registered Peak Load ("MRPL"). Specifically, I address the arguments raised by the Office of Consumer Advocate ("OCA") regarding procurement efficiency. I also respond to Direct Testimony presented by the Solar Energy Industries Association ("SEIA") and the Coalition for Community Access (collectively, "Joint Solar Advocates" or "JSA") regarding grandfathering (legacy rights) eligibility, increasing the non-refundable deposit of estimated distribution

upgrade costs from 25 percent to 50 percent, and the transfer of Alternative Energy Credits ("AECs") to PPL Electric Utilities Corporation ("PPL" or "Company").

Q. ON THE TOPICS OF REBUTTAL, PLEASE SUMMARIZE WALMART'S RECOMMENDATIONS TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("COMMISSION").

A. Walmart's recommendations to the Commission are as follows:

Walmart respectfully recommends that the Commission reject the OCA's recommendation to change how customer-generators are classified under the Generation Supply Charge ("GSC"), as it:

(a) Abruptly and sharply shifts customer-generators above 100 kW to hourly Locational Marginal Pricing ("LMP")-based kWh generation valuation under GSC-2, which would fundamentally change project value propositions;

(b) Provides no evidence from PPL that supports the claim that inefficiencies will be improved by subjecting large customer-generators to GSC-2 real-time pricing;

(c) Mischaracterizes all large customer-generators as those whose output is uncertain; and

(d) Disincentivizes generation in PPL's territory at a time when capacity markets are seeing extremely high prices and forecasts are trending toward increasing demand.

If the Commission approves PPL's MRPL proposal – which Walmart continues to oppose:

(a) Walmart recommends that the threshold date for legacy rights eligibility should be twelve months after the Final Order in this case is issued, to avoid retroactive harm to investments already in progress. This would allow a reasonable time horizon for projects that are in-flight, whose project economics rely on the current tariff, to enter the interconnection queue without the risk of being blindsided mid-stream. The Commission must ensure that the transition mechanism captures all projects developed in reliance on the current tariff, not just those that happened to file paperwork before August 29, 2025.

(b) Walmart recommends that the Commission reject the provision proposed by the JSA that would require "Transition Facilities" to transfer AECs to PPL. Legacy rights or grandfathering should be based on the date of investment commitment and reliance on existing tariffs, as discussed in Section III of my Rebuttal Testimony, without requiring customer-generators to forfeit the environmental and economic value of the energy they generate.

(c) Walmart recommends that the Commission reject the JSA's proposal to increase the non-refundable deposit of estimated distribution upgrade costs from the current 25 percent to 50 percent for Transition Facilities. Eligibility for GSC-1 legacy rights should be determined based on the project's existence in the interconnection queue as of twelve months after the Final Order for this case has been issued – as I discuss in Section III – without

imposing retroactive financial penalties that increase the risk profile of renewable energy investments in Pennsylvania.

III. Response to the OCA Regarding MRPL Classification

Q. PLEASE SUMMARIZE THE OCA'S POSITION ON PPL'S MRPL PROPOSAL.

A. OCA witness Zach Teti recommends that the Commission approve PPL's proposed MRPL methodology. Mr. Teti argues that moving larger customer-generators to the GSC-2 rate would make default service procurement for the GSC-1 class more straightforward and efficient by removing the uncertainty of customer-generator output from full requirements contracts.[1]

Q. DOES WALMART AGREE WITH THE OCA'S METHODOLOGY?

A. No. Mr. Teti explicitly admits that he did not conduct an analysis on the risk premiums for PPL.[2] He is asking the Commission to fundamentally alter the economics of customer investments based on an assumption of inefficiency, rather than empirical evidence that large commercial and industrial ("C&I") projects actually caused higher risk premiums in PPL's recent auctions.

Walmart's decision to install solar is based on active evaluation and capital planning, not short-term market fluctuation. Therefore, the "switching risk" (the fear that these projects will suddenly leave default service for the wholesale market)

[1] *See* Direct Testimony of Zach Teti ("Teti Direct"), p. 3, lines 9-11.
[2] *See id.* at 11, lines 11-13.

cited by the OCA is overstated and not categorical for customers who prioritize long-term budget certainty and sustainability over short-term arbitrage.

While Walmart supports efficient procurement, the OCA's position ignores the detrimental impact this reclassification would have on distributed energy resource ("DER") solar development, which in turn would likely negatively impact Pennsylvania's Climate Action Plan 2024 for deploying onsite solar to meet ~80 percent reduction by 2050 of Greenhouse Gase emissions.[3]

As stated in my Direct Testimony, shifting customer-generators to hourly LMP under GSC-2 fundamentally alters the value proposition for onsite solar. This creates a disincentive for generation at a time when capacity markets are tightening and demand is increasing.

Q. WHAT IS WALMART'S RECOMMENDATION REGARDING THE OCA'S POSITION ON PPL'S MRPL PROPOSAL?

A. Walmart respectfully recommends that the Commission reject the OCA's recommendation to change how customer-generators are classified under the GSC, as it:

(a) Abruptly and sharply shifts customer-generators above 100 kW to hourly LMP-based kWh generation valuation under GSC-2, which would fundamentally change project value propositions;

[3] *See* Pennsylvania Climate Action Plan 2024, p. 80 https://greenport.pa.gov/elibrary/GetDocument?docId=9584245&DocName=PENNSYLVANIA%20CLIMATE%20ACTION%20PLAN%202024.PDF%20%20%3Cspan%20style%3D%22color%3Agreen%3B%22%3E%3C%2Fspan%3E%20%3Cspan%20style%3D%22color%3Ablue%3B%22%3E(NEW)%3C%2Fspan%3E.

(b) Provides no evidence from PPL that supports the claim that inefficiencies will be improved by subjecting large customer-generators to GSC-2 real-time pricing;

(c) Mischaracterizes all large customer-generators as those whose output is uncertain; and

(d) Disincentivizes generation in PPL's territory at a time when capacity markets are seeing extremely high prices and forecasts are trending toward increasing demand.

IV. Response to the JSA's Direct Testimony Regarding Legacy Rights Proposal

Q. PLEASE DESCRIBE THE LEGACY RIGHTS FRAMEWORK PROPOSED BY JSA WITNESS BARNES.

A. JSA witness Justin Barnes proposes a legacy rights framework that categorizes projects into "Existing Facilities" and "Transition Facilities." Mr. Barnes defines "Existing Facilities" as facilities that were either operational or for which interconnection upgrade work orders are under construction as of the date of PPL's rate filing in this proceeding.[4] He defines "Transition Facilities" as

> [front of the meter ("FTM") distributed generation ("DG")] facilities with pending interconnection requests submitted prior to the date of PPL's rate application in this proceeding, for which the FTM DG customer makes a one-time election to both: (i) make a non-refundable deposit of 50 percent of the Company's estimated costs of distribution upgrades (cumulative), and (ii) transfer AECs produced by the project to PPL at no cost for the term of the legacy

[4] *See* Direct Testimony of Justin R. Barnes ("Barnes Direct"), p. 37, lines 19-21.

rights period. Such "cumulative" amounts would include any non-refundable payments that have already been made.[5]

Any project not meeting these strict criteria, or if the project owner elects to retain AEC ownership or declines to pay the 50 percent enhanced distribution upgrade deposit, would be a Non-Legacy Facility – and classified as a "Non-Legacy Project" subject to the new GSC-2 rate classification.[6]

Q. HOW DOES THIS POSITION ALIGN WITH THE TESTIMONY OF OTHER INTERVENORS?

A. Aspen Power, 38 Egress, CVE North America, Syncarpha Capital, LLC, Twilight Renewables, Bollinger Solar, and CEP Renewables (collectively, "Customer-Generator Coalition" or "CGC") witness Guy Sharfman argues that existing customer-generators modeled the economic viability of their installations based on the GSC-1 Price to Compare ("PTC") revenue stream.[7] Mr. Sharfman contends that changing the rules now would effectively "renege on the promises made to these solar generators."[8] He specifically recommends that if the Commission adopts the rule change, it should apply only to new customer-generators to ensure existing investors are not "blindsided" and that existing investors are protected.[9]

Similarly, Professional Dairy Managers of PA ("PDMP") witness James Harbach testified that PPL's proposal changes the deal mid-stream to the detriment of customers who invested substantial sums of money based on the economics of

[5] *See id*. at 38, lines 2-8.
[6] *See id*. at 38, lines 12-14.
[7] *See* Direct Testimony of Guy Sharfman ("Sharfman Direct"), p. 29, lines 6-9.
[8] *See id*. at 22, lines 14-16.
[9] *See id*. at 29, lines 19-22.

the current tariff.[10] Mr. Harbach noted that his business has been "blindsided" by these proposed changes, which would destroy the economic model required to keep his operations sustainable.[11]

Q. DOES WALMART SUPPORT THE CUTOFF DATE OF AUGUST 29, 2025, PROPOSED BY MR. BARNES?

A. No. While Walmart agrees with the concept of legacy rights to protect investments made in reliance on existing tariffs, Mr. Barnes' proposal to use the rate filing date (August 29, 2025) as the eligibility cutoff is unreasonably restrictive and arbitrary. This retrospective cutoff fails to account for projects that are currently in advanced stages of development where capital has been budgeted – but which had not formally entered the PPL interconnection queue by the date PPL filed this case.

Q. WHY IS THE AUGUST 29, 2025, CUTOFF PROBLEMATIC FOR CUSTOMER-GENERATORS LIKE WALMART?

A. Walmart and perhaps other customers are victims of the timing of a base rate case filing for which, absent this filing, this issue would be non-existent. Commercial customer-generators like Walmart operate with long planning horizons. It actively evaluates onsite solar opportunities and can allocate capital months or even a year or more before an interconnection application is formally submitted to the utility.

The JSA proposal defines eligibility based on a date that has already passed and fails to account for projects that are currently in advanced development stages – where capital has been budgeted and design work has begun – but which had not

[10] *See* Direct Testimony of James Harbach ("Harbach Direct"), p. 9, lines 11-12.
[11] *See id.* at 6, lines 13-19.

formally entered the PPL interconnection queue by August 29, 2025. These projects in advanced development stages that may have been in planning and design work for up to a year or more should not be penalized because of the timing of the Company filing a general rate case. As CGC witness Sharfman notes, customers who made economic decisions based on the GSC-1 PTC should not be "blindsided" by rule changes. Establishing a retroactive cutoff date effectively blindsides any customer who invested in project development in 2025 under the assumption that current tariff rules would apply until the Commission issued a Final Order.

Q. WHAT IS WALMART'S RECOMMENDATION REGARDING THE GRANDFATHERING TIMELINE?

A. Walmart is concerned that JSA's specific definitions of "Existing Facilities" and "Transition Facilities" leaves a gap. It protects those already in the queue but abandons projects that are in-flight – up to a year or more in planning work – but not yet filed. Under the JSA proposal, these projects would be classified as "Non-Legacy Projects" and subjected to the GSC-2 rate, destroying the economics upon which the internal funding decisions were made.

To address this issue, Walmart recommends that the threshold date for legacy rights eligibility be twelve months after the Final Order in this rate case is issued, to avoid harm to investments already in progress. This would allow a reasonable time horizon for projects that are in-flight, whose project economics rely on the current tariff, to enter the interconnection queue without the risk of being blindsided mid-stream. The Commission must ensure that the transition mechanism

captures all projects developed in reliance on the current tariff, not just those that happened to file paperwork before August 29, 2025, or even before a Final Order.

V. Response to the JSA's Direct Testimony Regarding AEC Forfeiture

Q. DOES WALMART SUPPORT THE JSA'S PROPOSAL REGARDING AECs?

A. No, it does not. While Walmart appreciates the JSA's effort to create a pathway for projects currently in the interconnection queue to remain on the GSC-1 rate, specific conditions attached to the "Transition Facilities" classification would significantly limit Walmart's ability to develop future projects that do not qualify under that definition. Specifically, Walmart opposes the requirement that these customer-generators transfer their AECs to PPL at no cost for the operational life of the facility.

Q. WHY IS THE FORFEITURE OF AECs PROBLEMATIC FOR WALMART?

A. The forfeiture of AECs renders the "Transition Facility" classification economically and strategically unviable for Walmart, and potentially other commercial customers as well, for two primary reasons: (1) it removes a critical revenue stream that supports project economics, and (2) it undermines sustainability objectives that drive investment in onsite generation.

Q. PLEASE EXPLAIN THE ECONOMIC IMPACT OF FORFEITING AECs.

A. JSA witness Justin Barnes refers to recent Alternative Energy Portfolio Standards Act ("AEPS") compliance reporting data that AEC prices have risen significantly

in recent years, citing Tier 1 AEC prices rising from $6.31/MWh in 2019 to $31.01/MWh in 2024.[12] The AECs represent both a material environmental and financial component of a solar project's return on investment. Mr. Barnes argues that the transfer of the AECs is necessary to bridge a "value gap" between the GSC-1 cash-out rate and the cost reductions that excess generation provides.[13] However, from a customer-generator's perspective, this proposal effectively swaps one financial penalty for another. PPL's proposal threatens projects by moving them to the volatile GSC-2 rate. The JSA proposal attempts to "save" these projects by keeping them on GSC-1, but only if they surrender the valuable AEC asset. For a large commercial customer like Walmart, removing the AEC revenue stream can be just as damaging to project viability as the rate reclassification itself.

Q. HOW DOES THE PROPOSAL IMPACT WALMART'S SUSTAINABILITY GOALS?

A. As stated in my Direct Testimony, Walmart has set aggressive goals to be supplied 100 percent by renewable energy by 2035 and to achieve zero carbon emissions in its operations by 2040. Walmart has also announced a goal to enable 1 GW of new onsite solar plus storage by the end of 2030, which will require Walmart, the system owner, to retain and retire the AECs associated with that generation. If Walmart is forced to transfer these AECs to PPL as a condition of interconnection or rate classification, PPL – not Walmart – would hold the environmental attributes of that energy. Because PPL could use the AECs to reduce its own AEPS compliance

[12] *See* Barnes Direct, p. 44, lines 16-18.
[13] *See id.* at 42, lines 14-17.

volume, Walmart would be unable to count that generation toward its renewable energy targets. This undermines a key objective of implementing onsite solar solutions and effectively renders the JSA's "Transition" mechanism ineffective for customers like Walmart who have similar corporate sustainability requirements.

Q. WHAT IS WALMART'S RECOMMENDATION REGARDING THE AEC TRANSFER REQUIREMENT?

A. Walmart recommends that the Commission reject the provision in the JSA proposal that requires "Transition Facilities" to transfer AECs to PPL. Legacy rights or grandfathering should not require customer-generators to forfeit the environmental and economic value of the credit for the energy that they themselves – not the Company – generate.

VI. Response to the JSA's Direct Testimony Regarding Distribution Upgrade Deposits

Q. DOES WALMART SUPPORT THE FINANCIAL REQUIREMENTS PROPOSED BY THE JSA FOR "TRANSITION FACILITIES" TO MAINTAIN GSC-1 ELIGIBILITY?

A. No, it does not. In addition to the forfeiture of AECs discussed previously, JSA witness Justin Barnes proposes that for a project to qualify as a "Transition Facility" – and thereby retain GSC-1 classification – the customer must make a non-refundable deposit to PPL of 50 percent of PPL's estimated costs of distribution upgrades (cumulative).[14] Walmart opposes this requirement as it creates an

[14] *See id.* at 38, lines 2-6.

unreasonable financial barrier to interconnection and unfairly shifts risk onto the customer-generator.

Q. WHY DOES WALMART OPPOSE INCREASING THE DEPOSIT TO 50 PERCENT?

A. Increasing the non-refundable deposit of estimated distribution upgrade costs from the current 25 percent to 50 percent imposes an excessive financial penalty on projects that are already in the development pipeline. Large commercial customers like Walmart typically allocate capital based on project economics. To require 50 percent of the capital for upgrades is an unreasonable "Pay to Stay" premium and exposes the customer to significant risk should the project become unviable due to factors outside the customer's control, such as changes in PPL's cost estimates, timeline delays, changes to international trade tariffs, or other regulatory hurdles.

Furthermore, relying on PPL's estimated costs for this deposit is problematic. If PPL's cost estimates are inaccurate or subject to change, the customer is forced to lock up significant capital based on a moving target. Increasing the financial burden to simply retain eligibility for a rate class (GSC-1) that the customer was entitled to when they applied for interconnection is punitive.

Q. HOW DOES THIS PROPOSAL IMPACT WALMART'S ABILITY TO DEVELOP ONSITE GENERATION?

A. As stated in my Direct Testimony, Walmart seeks to avoid disincentivizing generation in PPL's territory. A requirement to pay a non-refundable 50 percent deposit effectively acts as a barrier to entry or a mechanism to force project cancellations. It changes the economic "rules of the game" mid-stream for projects

that have already been scoped and funded internally based on existing tariff requirements. Doubling the standard deposit requirement (from the current 25 percent noted by Mr. Barnes to 50 percent) and making it a condition of rate classification is an arbitrary hurdle that discourages investment.

Q. WHAT IS WALMART'S RECOMMENDATION?

A. Walmart recommends the Commission reject the JSA's proposal to increase the non-refundable deposit of estimated distribution upgrade costs from the current 25 percent to 50 percent for "Transition Facilities." Eligibility for GSC-1 legacy rights should be determined based on the project's presence on the interconnection queue as of twelve months after the Final Order for this case has been issued – as I discussed in Section III – without imposing retroactive financial penalties that increase the risk profile of renewable energy investments in Pennsylvania.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3057164
	:	
PPL Electric Utilities Corporation	:	

VERIFICATION

I, Matthew T. Lyon, hereby state that the facts in my Rebuttal Testimony, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at any hearing held in this matter. I understand the statements herein are made subject to the penalties of 18 Pa. C.S. §4904 (relating to falsification to authorities).

Date: 1/23/2026

Type text here

Matthew T. Lyon
Walmart Inc.

WALMART STATEMENT NO. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3057164
	:	
PPL Electric Utilities Corporation	:	

SURREBUTTAL TESTIMONY OF

MATTHEW T. LYON

ON BEHALF OF

WALMART INC.

FEBRUARY 9, 2026

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I. Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Matthew T. Lyon. My business address is 814 Respect Drive, Bentonville, AR 72716. I am employed by Walmart Inc. ("Walmart") as a Senior Manager, Utility Partnerships – Regulatory.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of Walmart.

Q. ARE YOU THE SAME MATTHEW T. LYON WHO PREVIOUSLY SUBMITTED DIRECT TESTIMONY AND REBUTTAL TESTIMONY IN THIS PROCEEDING ON BEHALF OF WALMART?

A. Yes.

II. Purpose of Surrebuttal Testimony and Summary of Recommendations

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimony of PPL Electric Utilities Corporation ("PPL" or "Company") regarding the proposed reclassification of customer-generators based on Maximum Registered Peak Load ("MRPL"). Specifically, I address the rebuttal arguments raised by Company witness Castanaro regarding proposed changes to compensation for solar energy produced by customer-generators, generation investment disincentivization and customer impacts, characterization of all large customer-generators as "merchant generators," materiality of impact, Exhibit AC-3R, and project viability.

III. Response To PPL Regarding Proposed Changes To Compensation For Solar Energy Produced By Customer-Generators

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED CHANGES TO COMPENSATION FOR SOLAR ENERGY PRODUCED BY CUSTOMER-GENERATORS?

A. The Company proposes significant changes to how customer-generators are classified under the Generation Supply Charge ("GSC") rate structure. The Company seeks to classify customers on the GSC into two distinct categories: Rate GSC-1 (Small Commercial and Industrial – < 100 kW) and GSC-2 (Large Commercial and Industrial – > 100 kW), based on their maximum registered peak load and PPL's revised definition of maximum registered peak load in the proposed tariff.[1]

Q. PPL ARGUES THAT THE PROPOSAL IS NOT INTENDED TO DISINCENTIVIZE SOLAR DEVELOPMENT AND STATES THAT ONLY 18 EXISTING CUSTOMERS WOULD BE RECLASSIFIED. DO YOU AGREE THAT THE IMPACT IS MINIMAL?

A. No. Company witness Castanaro testifies that "only 18 existing customer-generators would be reclassified from GSC-1 to GSC-2" to support his claim that the impact is limited.[2] However, this statistic ignores the "chilling effect" that the proposal has on the pipeline of future projects. As stated in my Direct Testimony, Walmart has aggressive goals to enable 1 GW of new onsite solar.[3] The fact that

[1] *See* Direct Testimony of Andrew Castanaro ("Castanaro Direct"), p. 2, lines 7-10.
[2] *See* Rebuttal Testimony of Andrew Castanaro ("Castanaro Rebuttal"), p. 17, lines 15-17.
[3] *See* Direct Testimony of Matthew T. Lyon ("Lyon Direct"), p. 19, lines 18-21.

few existing customers currently trigger the threshold is irrelevant to the decision-making process for future investments. By Mr. Castanaro's own admission, the proposal is intended to establish "forward-looking rate classifications."[4] Therefore, the relevant metric is not how many customers are affected today, but how many planned projects – like those Walmart is evaluating – will be rendered uneconomic, and thus terminated, due to this change.

Q. MR. CASTANARO DISAGREES WITH YOUR DIRECT TESTIMONY THAT THE PROPOSAL DISINCENTIVIZES GENERATION. WHAT IS YOUR RESPONSE?

A. Mr. Castanaro argues that the proposal is not intended to disincentivize onsite solar development but rather to ensure equitable classification; however, the intent is secondary to the economic reality.[5] Moving a customer from a stable GSC-1 credit structure to an hourly, volatile Locational Marginal Pricing ("LMP") structure under GSC-2 fundamentally alters the "value proposition" I described in my Direct Testimony.[6] For a large commercial customer, the administrative burden and financial risk of managing hourly wholesale settlements are significant barriers. If the economics of a project collapse because the compensation mechanism changes from a predictable Price to Compare ("PTC") structure to a volatile LMP structure, then the project is disincentivized regardless of PPL's stated intent.

[4] *See* Castanaro Rebuttal at 43, lines 18-20.
[5] *See id.* at 42, lines 9-13.
[6] *See* Lyon Direct, p. 20, lines 6-9.

IV. Response To Mr. Castanaro Regarding Generation Investment Disincentivization And Customer Impacts

Q. MR. CASTANARO ARGUES THAT IT IS "UNREASONABLE FOR CUSTOMER-GENERATORS TO RELY ON A STABLE PTC" BECAUSE RATES ALWAYS CHANGE.[7] WHAT IS YOUR RESPONSE?

A. Mr. Castanaro conflates *rate* volatility with *structural* volatility. He argues that because the PTC changes over time, customers have already accepted risk.[8] This is a false equivalence. Walmart understands that the value of the PTC ($/kWh) fluctuates with market conditions. However, Walmart has been relying on the structure of the GSC-1 rate remaining the compensation mechanism for onsite generation for the projects that Walmart has in development. This may be true for many other current and prospective customer-generators. There is a fundamental difference between a rate that fluctuates based on energy auctions (GSC-1) and a complete structural shift to hourly real-time market pricing (GSC-2) that removes capacity and transmission values from the credit. Mr. Castanaro asserts that existing investments do not "preclude necessary updates to rate design."[9] However, changing the fundamental compensation structure for projects that were developed and budgeted under a different regulatory compact constitutes harm to those projects. This is why Walmart proposes a 12-month transition window in my Rebuttal Testimony – to protect projects that relied on the GSC-1 structure during their development phase.

[7] Castanaro Rebuttal, p. 44, lines1-4.
[8] *See id.* at 15, lines 4-12.
[9] *See id.* at 43, line 21to p. 44, line 1.

V. Response To Characterization Of All Large Customer-Generators As "Merchant Generators"

Q. MR. CASTANARO REFERS TO LARGE CUSTOMER-GENERATORS AS "MERCHANT GENERATORS" WHO ARE BANKING ON HIGH RATES AND HAVE NO INCENTIVE TO MITIGATE RATE INCREASES.[10] IS THIS ACCURATE FOR WALMART?

A. No. Mr. Castanaro's characterization paints with too broad a brush and ignores certain customer-generators' broader relationship with PPL. Walmart, for instance, is one of the largest retail customers in PPL's Pennsylvania territory, with 37 retail stores, four distribution centers, six fuel stations, and related facilities.[11] While the specific accounts in question may be "no-load" generators, Walmart as an entity is a significant net consumer of electricity in Pennsylvania. Therefore, Mr. Castanaro's claim that we have "no financial incentive" to support measures that mitigate PTC increases is factually incorrect.[12] Walmart pays the PTC on its substantial retail load and has a vested interest in affordable and reasonable rates for all customers. Walmart's status as a "no-load" generator under specific accounts at specific sites results from oversizing production relative to load in order to maximize clean energy production. This strategy accelerates progress toward Walmart's 1 GW onsite generation goal and reduces emissions, which contributes to Pennsylvania's clean energy goals as well. Crucially, by injecting excess carbon-free power, Walmart helps alleviate strain on the load-constrained PJM

[10] *Id.* at p. 9, lines 1-18.
[11] https://corporate.walmart.com/about/location-facts/united-states/pennsylvania
[12] Castanaro Rebuttal, p. 13, lines 5-7.

Interconnection, LLC ("PJM"), grid, providing system-wide reliability benefits while meeting corporate clean energy targets.

Q. BUT MR. CASTANARO ARGUES THAT THESE PROJECTS ARE RELYING ON INFLATED PTC RATES TO BE PROFITABLE. HOW DO YOU RESPOND TO THE IMPLIED CRITICISM OF YOUR INVESTMENT MODEL?

A. Mr. Castanaro criticizes customers for making economic decisions based on the price signals that PPL's own tariff provided.[13] Whether a project is designed to offset immediate load or to generate credits toward corporate clean energy goals, the investment is calculated based on the regulatory structure in place – specifically, the value of the GSC-1 credit. Labeling these projects as "merchant generators" is a rhetorical attempt to justify retroactively changing that value proposition. Walmart's project evaluation is based on the "rules of the road" established by PPL and approved by the Pennsylvania Public Utility Commission ("Commission") and should not be penalized for this. PPL's proposal penalizes customers for responding rationally to those existing price signals. The issue is not whether the project "arbitrages" the rate; the issue is whether the utility should be permitted to upend the economic basis of an investment after deployment, and in at least 18 cases cited by Mr. Castanaro, projects that are already operational. This creates "stranded value" for customers who acted reasonably under the current rules.

[13] *See id.* at 9, lines 9-12.

VI. Response To Mr. Castanaro Regarding Materiality Of Impact

Q. MR. CASTANARO ARGUES THAT THE MRPL PROPOSAL IS NECESSARY TO ADDRESS CROSS-SUBSIDIZATION, YET HE STATES THAT ONLY 18 EXISTING CUSTOMER-GENERATORS WOULD BE RECLASSIFIED. DOES THIS STATISTIC SUPPORT THE COMPANY'S POSITION?

A. No, it effectively undermines it. Mr. Castanaro admits that of the approximately 1,250 commercial customer-generator installations on the system as of January 5, 2026, only 18 would be reclassified from GSC-1 to GSC-2 if the proposal were approved.[14] This means that PPL is proposing a fundamental restructuring of its default service rate applicability to address a subset of customers comprising just 1.44 percent of its commercial generating base. Furthermore, these 18 customers likely represent a small fraction of the total GSC-1 (Small Commercial and Industrial ("C&I")) rate class, which includes thousands of small businesses. Implementing a sweeping policy change to address an issue caused by less than two dozen customers that fundamentally alters the value proposition for current onsite generation, chills near-future investment, and creates unnecessary hurdles to achieving the Commonwealth's clean energy goals suggests that the Company's proposed remedy is overly broad and disproportionate to the current scope of the issue.

[14] *See* Castanaro Rebuttal at 17, lines 15-17.

Q. DOES THE CONTENTION THAT "ONLY 18" CUSTOMERS ARE AFFECTED MITIGATE THE HARM TO WALMART AND OTHERS?

A. No. Mr. Castanaro uses the "only 18" figure to imply the impact to projects is minimal. This ignores the pipeline of future investment. As noted in my Direct Testimony, Walmart has a goal to bring 1 GW of new clean energy projects online, with Pennsylvania projects playing a material role. The relevant metric is not the negative impact to a handful of customers today, but the negative impact to near-future projects that will be rendered uneconomic by this change. By focusing on the small number of current customers negatively impacted, PPL obscures the significant harm it would inflict on would-be customer-generators who acted in good faith by investing in the future of distributed generation and clean energy goals of Pennsylvania.

VII. Response To Mr. Castanaro Regarding Exhibit AC-3R And Project Viability

Q. MR. CASTANARO RELIES ON EXHIBIT AC-3R TO ARGUE THAT THE FINANCIAL IMPACT OF THE MRPL PROPOSAL ON CUSTOMER-GENERATORS IS INCONSISTENT. DOES THIS EXHIBIT SUPPORT HIS CONCLUSION THAT THE HARM IS UNRELIABLE OR OVERSTATED?

A. No. In fact, Exhibit AC-3R provides concrete evidence that the MRPL proposal is fatal to the economics of distributed generation projects, regardless of the specific variance among developers. Mr. Castanaro focuses on the range of the data – noting that revenue reduction projections vary from a low of 14.77 percent to a high of 57.18 percent – to argue that there is "great inconsistency" among the CGC

coalition members.[15] He uses this variance to dismiss their concerns. However, this interpretation ignores the severity of the floor. Even the most conservative impact shown in the exhibit – 14.77 percent – is likely to be economically devastating for long-term infrastructure assets.

Q. WHY IS A 14.77 PERCENT REVENUE REDUCTION SIGNIFICANT FOR THESE PROJECTS?

A. Solar energy projects are capital-intensive investments, often times with thin operating margins and financed over 20 to 30 years. A permanent 15 percent reduction in gross top-line revenue can exceed the project's entire profit margin. For many projects, a 15 percent drop in revenue would cause the project's Debt Service Coverage Ratio ("DSCR") to fall below lender requirements, triggering default or making the project unfinanceable from the start. Therefore, Mr. Castanaro's Exhibit AC-3R does not prove that the harm is "inconsistent;" it proves that the harm could be catastrophic. Whether a project loses 15 percent of its revenue or 57 percent of its revenue, the outcome is the same: the project becomes uneconomic and future development halts. Exhibit AC-3R confirms that the MRPL proposal effectively kills the economics for the entire asset class, validating Walmart's concern regarding the chilling effect on its future 1 GW goals and similar goals that other customers may share.

[15] *See* Castanaro Rebuttal at Exhibit AC-3R ("Exhibit AC-3R").

VIII. Conclusion

Q. DOES MR. CASTANARO'S REBUTTAL CHANGE YOUR RECOMMENDATIONS?

A. No. In fact, Mr. Castanaro's rebuttal reinforces the need for the Commission to reject the Company's proposal. By insisting on a strict application of the MRPL based on a static view of "18 existing customers," PPL ignores the dynamic reality of the energy market. Furthermore, Mr. Castanaro's referenced data in Exhibit AC-3R confirms that the proposal destroys the economic viability of distributed generation projects, rendering even the most robust projects unfinanceable. Mr. Castanaro's position effectively closes the door on future distributed generation development in PPL's territory. This outcome is directly at odds with Pennsylvania's clean energy goals and the clean energy goals of large customers like Walmart. At a time when the Commonwealth should be encouraging diverse generation resources to meet rising demand and capacity constraints, PPL's proposal creates a hostile economic environment that will halt new solar investment.

Q. WHAT IS WALMART'S FINAL RECOMMENDATION TO THE COMMISSION?

A. Walmart respectfully recommends that the Commission reject PPL's MRPL proposal. The proposal creates "stranded value" for existing investments and chills the pipeline for future projects necessary to meet corporate and state energy targets. However, should the Commission approve the MRPL methodology, it is critical

that the implementation includes the robust transition protections I outlined in my Rebuttal Testimony. Specifically:

1. A 12-Month Transition Window: The eligibility cutoff for legacy rights in which customer-generators may remain on GSC-1 should be set to twelve months after the date of the Final Order in this proceeding. This window is necessary to protect "in-flight" projects – those where capital has been committed based on the current GSC-1 structure but have not yet entered the interconnection queue – preventing developers and customers from being "blindsided" by a mid-stream rule change.
2. No Forfeiture of Alternative Energy Credits ("AECs"): The Commission should reject any requirement for customers to forfeit AECs as a condition of grandfathering. Forcing customers to surrender the environmental attributes of their generation undermines the very clean energy goals that drive these investments in the first place.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3057164
	:	
PPL Electric Utilities Corporation	:	

VERIFICATION

I, Matthew T. Lyon, hereby state that the facts in my Surrebuttal Testimony, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at any hearing held in this matter. I understand the statements herein are made subject to the penalties of 18 Pa. C.S. §4904 (relating to falsification to authorities).

Date: February 9, 2026

Matthew T Lyon

Matthew T. Lyon
Walmart Inc.

WALMART STATEMENT NO. SRJ-1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3057164
	:	
PPL Electric Utilities Corporation	:	

SURREJOINDER TESTIMONY OF

MATTHEW T. LYON

ON BEHALF OF

WALMART INC.

MARCH 2, 2026

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I. Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Matthew T. Lyon. My business address is 814 Respect Drive, Bentonville, AR 72716. I am employed by Walmart Inc. ("Walmart") as a Senior Manager, Utility Partnerships – Regulatory.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of Walmart.

Q. ARE YOU THE SAME MATTHEW T. LYON WHO PREVIOUSLY SUBMITTED DIRECT TESTIMONY, REBUTTAL TESTIMONY, AND SURREBUTTAL TESTIMONY IN THIS PROCEEDING ON BEHALF OF WALMART?

A. Yes.

II. Purpose of Surrejoinder Testimony

Q. WHAT IS THE PURPOSE OF YOUR SURREJOINDER TESTIMONY?

A. The purpose of my Surrejoinder Testimony is to respond to the Rejoinder Testimony of PPL Electric Utilities Corporation ("PPL") witness Andrew Castanaro (PPL Electric Statement No. 15-RJ). Specifically, I will address his mischaracterization of Walmart's corporate sustainability strategy, respond to his claim that a transition window is inappropriate due to his revised net metering cost projections, and evaluate PPL's concession to add a capacity component to the GSC-2 net metering cash-out rate.

III. Response to Mr. Castanaro Regarding Walmart's Motives

Q. MR. CASTANARO CLAIMS THAT IF WALMART'S GOAL WAS TRULY TO REDUCE EMISSIONS, NOTHING PREVENTS WALMART FROM INSTALLING SOLAR AT RETAIL SITES. HE CONCLUDES WALMART IS PURSUING "NO-LOAD" SITES SOLELY "TO MAXIMIZE THE AMOUNT OF COMPENSATION."[1] HOW DO YOU RESPOND?

A. Mr. Castanaro's claim fundamentally misrepresents Walmart's goals. As I stated in my Direct Testimony, Walmart has announced a goal to bring 10 GW of new clean energy projects online by the end of 2030, including 1 GW of new onsite solar plus storage. To achieve these massive sustainability targets, Walmart actively evaluates onsite solar opportunities across the United States. As noted in my previous testimony, our status as a "no-load" generator at specific sites is a deliberate strategy of oversizing production relative to load in order to maximize clean energy production.

[1] Rejoinder Testimony of Andrew Castanaro ("Castanaro Rejoinder"), p. 13, lines 14-17.

IV. Response to Mr. Castanaro Regarding the Transition Window

Q. IN HIS REJOINDER, MR. CASTANARO CORRECTED HIS MODELING, RESULTING IN PROJECTED NET METERING EXPENSES JUMPING TO $795 MILLION BY 2029. HE ARGUES THIS MEANS PPL MUST IMPLEMENT THE MAXIMUM REGISTERED PEAK LOAD ("MRPL") NOW AND IGNORES THE "CHILLING EFFECT" ON FUTURE PROJECTS. DOES THIS CHANGE YOUR POSITION ON THE 12-MONTH TRANSITION WINDOW?

A. No, it does not. In fact, if developers are investing at the scale Mr. Castanaro projects, it only highlights the significant amount of capital that has been committed in reliance on PPL's current tariff structure. As I stated in my Rebuttal Testimony, commercial customers operate with long planning horizons and allocate capital months or even a year before an interconnection application is formally filed. Changing the rules abruptly and retroactively alters the economics of these "in-flight" investments. Therefore, Walmart continues to strongly recommend that if the Pennsylvania Public Utility Commission ("Commission") approves the MRPL construct, the threshold date for legacy rights eligibility must be twelve months after the Final Order in this case is issued. This ensures that rational actors who made economic decisions based on the current rules are not "blindsided" mid-stream.

V. Evaluation of the GSC-2 Capacity Concession

Q. IN HIS REJOINDER, MR. CASTANARO STATED THAT PPL IS WILLING TO INCORPORATE A CAPACITY COMPONENT TO THE NET METERING COMPENSATION CALCULATION FOR RATE GSC-2 CUSTOMER-GENERATORS. DOES THIS RESOLVE WALMART'S CONCERNS?

A. No. While adding a capacity component attempts to address the "value gap" identified by other intervenors, it does not cure the fundamental harm of forcing existing and in-flight projects onto the GSC-2 rate. The proposed shift to the GSC-2 rate still relies on an hourly Locational Marginal Pricing ("LMP")-based generation valuation. This exposes customer-generators to wholesale market volatility and fundamentally changes the value proposition upon which these projects were planned, designed, and budgeted.

Q. WHAT IS YOUR FINAL RECOMMENDATION?

A. Walmart continues to recommend that the Commission reject PPL's MRPL proposal entirely. Should the Commission approve it, the Commission should also mandate a 12-month grandfathering transition window post-Final Order to protect in-flight capital, and must explicitly reject any requirement for customers to forfeit their Alternative Energy Credits ("AECs") or pay punitive distribution upgrade deposits to retain their legacy status.

Q. DOES THIS CONCLUDE YOUR SURREJOINDER TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3057164
	:	
PPL Electric Utilities Corporation	:	

VERIFICATION

I, Matthew T. Lyon, hereby state that the facts in my Surrejoinder Testimony, are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at any hearing held in this matter. I understand the statements herein are made subject to the penalties of 18 Pa. C.S. §4904 (relating to falsification to authorities).

Date: 3/2/26

Matthew T. Lyon
Walmart Inc.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 15

Direct Testimony of Andrew Castanaro

Topics: **Maximum Registered Peak Load**

Dated: September 30, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew Castanaro. My business address is 827 Hausman Road, Allentown, Pennsylvania 18104.

Q. By whom are you employed and in what capacity?

A. I am employed by PPL Services Corporation ("PPL Services"), an affiliate of PPL Electric Utilities Corporation ("PPL Electric" or the "Company") that provides services to PPL Electric, as the Energy Procurement Manager.

Q. What are your responsibilities as Energy Procurement Manager?

A: My primary responsibilities include managing PPL Electric's Default Service auctions and related activities; managing energy contracts and associated credit provisions; and managing the alternative energy credit ("AEC") contracts and associated state reporting obligations. I am also responsible for similar programs in other jurisdictions in which PPL Electric affiliates operate.

Q. What is your educational background?

A: I graduated from Columbia University in 2006 with a Bachelor of Arts in Economics.

Q. Please describe your professional experience.

A. I began my career in 2010 with PPL Services in the Risk Management Department as a Market Analyst. In 2015, I joined Talen Energy, where I held the same title. In 2016,

I returned to PPL Electric as a Financial Analyst. In 2017, I joined the Financial Planning & Analysis Department within PPL Services. In 2023, I was promoted to Manager of Energy Procurement within the Regulatory Affairs Department of PPL Services, which is the position I currently hold.

Q. What is the purpose of your testimony?

A. I will testify about the Company's proposal to assign default supply customers on the Generation Supply Charge ("GSC") to Rate GSC-1 and Rate GSC-2 based on their maximum registered peak load, as defined by the Company's proposed retail tariff submitted in this proceeding.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring PPL Electric Exhibits AC-1 through AC-3.

II. MAXIMUM REGISTERED PEAK LOAD

Q. Why is PPL Electric proposing to change how it classifies customers under GSC-1 and GSC-2?

A. When it comes to assigning a GSC rate schedule, accurate customer classification is essential to ensure that costs are allocated and recovered fairly and that the rate structure reflects the realities of energy usage and generation patterns. The Company is making changes to how customers are classified, specifically in response to evolving trends in net metering installations and their impact on the existing rate classes.

A key driver of this change is the notable increase in "no load" net metering installations. These projects typically feature generation capacities exceeding 1 MW and can reach up to the maximum allowed 3 MW. Unlike traditional commercial and industrial customers, these installations have little or no onsite electric load—meaning they consume minimal energy from the grid—but they generate large amounts of electricity, and export significant excess generation back to the system. Under the current structure, the split between GSC-1 ("Small C&I") and GSC-2 ("Large C&I") customers is determined by a threshold of 100 kW peak demand. Customers with demand below this limit are categorized as GSC-1. However, no load net metering installations, despite their substantial generation output, have negligible net demand and, therefore, fall into the GSC-1 Small C&I category.

This classification does not account for the true nature or impact of these projects. While labeled as "small," these customer-generators often have infrastructure, financial investment, and grid impacts more akin to those of Large C&I entities. Under net metering rules, when these customers generate excess energy and receive compensation, the costs associated with paying for this excess generation are recovered from the same customer class as the customer-generator. Currently, this means the costs are allocated to Small C&I (GSC-1) customers taking default service—even though the scale and influence of these installations align more closely with Large C&I customers. This misalignment can result in an unfair distribution of default service costs. Small C&I customers taking default service end up bearing the financial burden for projects that, by virtue of their size and output, should be classified as Large C&I. This undermines the principle of equity in cost recovery and can distort the rate structure for

default service customers in the Small C&I class. The Company is proposing to revise the definition of "maximum registered peak load" in its tariff to account for not only peak demand, but also peak export to rectify this misalignment.

Q. Could you please provide background on the "maximum registered peak load" as defined by the Commission's regulations?

A. Although I am not an attorney, my understanding is that the Commission's regulations define "maximum registered peak load" as "[t]he highest level of demand for a particular customer, based on the PJM Interconnection, LLC, 'Peak Load Contribution Standard,' or its equivalent, and as may be further defined by the [Electric Distribution Company ('EDC')] tariff in a particular service territory." 52 Pa. Code § 54.182. Based on this authority, PPL Electric proposes to further define "maximum registered peak load" in its retail electric service tariff and utilize that new definition for the purpose of classifying customers into their respective rate schedules.

Q. To your knowledge, are there any other regulatory provisions relevant to the "maximum registered peak load" and its impact on customer classification?

A. Yes. The Commission's regulations provide:

> (h) Default service rates may not be adjusted more frequently than on a quarterly basis for all customer classes with a maximum registered peak load up to 25 kW, to ensure the recovery of costs reasonably incurred in acquiring electricity at the least cost to customers over time. DSPs may propose alternative divisions of customers by maximum registered peak load to preserve existing customer classes.
>
> (i) Default service rates shall be adjusted on a quarterly basis, or more frequently, for all customer classes with a maximum registered peak load of 25 kW to 500 kW, to ensure the recovery of costs reasonably

> incurred in acquiring electricity at the least cost to customers over time. DSPs may propose alternative divisions of customers by maximum registered peak load to preserve existing customer classes.
>
> (j) Default service rates shall be adjusted on a monthly basis, or more frequently, for all customer classes with a registered peak load of equal to or greater than 500 kW to ensure the recovery of costs reasonably incurred in acquiring electricity at the least cost to customers over time. DSPs may propose alternative divisions of customers by registered peak load to preserve existing customer classes.

52. Pa. Code § 54.187(h)-(j).

Q. What is the Company proposing with respect to "maximum registered peak load"?

A. In its proposed retail tariff filed in this proceeding (PPL Electric Exhibit GEO-1), "maximum registered peak load" is defined as "a customer's net demand contribution impact to the Company's default service procurement activity, as determined upon the net power flow from or into the Company's distribution system." The maximum registered peak load used to assign customers to their applicable rate schedule will be the customer's highest maximum registered peak load (kW) in the most recent 12-month period ending September 30. For new customers without a 12-month billing history, the maximum registered peak load shall be based on the Company's estimate using factors such as, but not limited to, similarly equipped buildings, and similarly utilized buildings and square footage. As related to customer-generators, this estimate shall also be inclusive of the nameplate capacity of the generation system.

Q. Why is the Company making this proposal?

A. PPL Electric is projecting a substantial increase in the number of customer-generators participating in net metering who do not have independent load to offset their electric

usage. As a result, those customer-generators by design produce excess generation that is banked until the end of the PJM Planning Year on May 31, at which point their banked generation is cashed out at the Price-to-Compare. The costs associated with the net metering credits and cash-outs are recovered from the default service customers in the customer-generators' respective customer classes.

The Company's currently effective tariff, which was last updated in the 2015 Rate Case, does not classify customers based on their maximum registered peak load as set forth in the proposed retail tariff. Instead, for example, a small commercial customer's demand is determined based on their load independent of the nameplate capacity of any behind-the-meter generation. This current practice fails to reflect the stress that the behind-the-meter generation puts on PPL Electric's distribution system. Additionally, the current classification results in non-net metering Small C&I default service customers disproportionately subsidizing the annual cash-outs of customer-generators that are, effectively, merchant generators.

Q. You mentioned that the Company is projecting a substantial increase in the number of customer-generators participating in net metering that do not have independent load to offset their electric usage. What do you mean by independent load?

A. By independent load, I mean load that would rely on PPL Electric's system for a separate purpose other than to operate the customer's generation.

Q. What is the impact of such customer-generators on the annual net metering cash-outs for the Small C&I customer class?

A. As of March 31, 2025, the annual net metering cash-outs for the Small C&I customer class totaled approximately $11 million. However, based on the level of interconnections projected over the next few years, PPL Electric estimates that the annual cash-outs for the Small C&I customer class will be approximately $60 million to over $300 million by 2029. (PPL Electric Exhibits AC-1 through AC-3.)[1]

Q. If the proposal is approved, what will be the impact on the large no-load customer-generators?

A. The large no-load customer-generators will be reclassified as Rate Schedule GSC-2 customers. This means that their excess generation will be paid out based on the GSC-2 rate. Likewise, the costs to pay for the excess net-metered generation will be recovered from the GSC-2 rate class, as opposed to the Small C&I customers in the GSC-1 rate case. The GSC-2 is calculated using real-time pricing based on the hourly generation needs of the customer class. This differs from the Small C&I GSC-1 rate, which is based on a combination of load following 12 and 24 month full requirements contracts. The majority of Large C&I customers are more sophisticated in managing their energy needs and are less likely to be impacted by an increase in default service rates because of an influx of net-metered generation. The real-time nature of the GSC-2 rate, and the sophistication of the Large C&I customers in the GSC-2 rate class

[1] PPL Electric Exhibits AC-1, AC-2, and AC-3 show projections based on cancellation rates for interconnection projects of 36%, 50%, and 75%, respectively.

mitigates the risk that there will be cross-subsidization between Small C&I customers and the large no-load customer-generators.

Q. How would the Company implement its maximum registered peak load proposal?

A. The Company would calculate the customers' maximum registered peak load annually and provide that information to the billing team, which would then determine which accounts need to be reclassified. Updated classifications would then be communicated to the affected customers approximately 30-60 days before service under their new rate schedule begins in June.

Q. Has the Commission approved any proposals that are similar to the Company's maximum registered peak load proposal?

A. Yes. In the Default Service Plan V ("DSP V") proceeding for UGI Utilities, Inc. – Electric Division ("UGI Electric") at Docket No. P-2024-3049343, *et al.*, the Commission approved a very similar proposal, under which UGI Electric classifies customers based on their "supply peak load impact." Although the Company is using the term "maximum registered peak load" instead of "supply peak load impact," the customer classification methodologies are effectively the same. It is my understanding that the Commission's February 20, 2025 Opinion and Order in that proceeding is currently on appeal before the Commonwealth Court of Pennsylvania as of the date of submitting this testimony.

Q. Does the Company believe that any waivers of the Commission's regulations are required to implement its proposal?

A. No. As I noted above, the Company maintains that its proposal is authorized by the existing provisions in the Commission's regulations. However, to the extent necessary, PPL Electric respectfully requests a waiver of the customer groupings recommended in 52 Pa. Code §§ 54.187 and 69.1805, along with any other Commission regulations or requirements that may be necessary to implement its proposal.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Year of Reconciliation/Cashout:	2024	2025	2026	2027	2028	2029	PTC at 12/1/30	
SCI Excess kWh for MGs (kWh Cashed Out)			60,202,851	391,960,372	932,128,980	1,430,455,085		<-- Updated 8/20/25
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114	$ 0.12575	$ 0.15067	$ 0.20474	$ 0.29515	
SCI Net Metering Expense from MGs			$ 7,292,672	$ 49,287,057	$ 140,441,077	$ 292,867,083		
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 18,134,146	$ 60,128,531	$ 151,282,551	$ 303,708,557		<--cashout amount to be reflected in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each column year
	^ Actual expense	*^ Actual expense*						

NOTES:
The amount of the net metering expense that is included in the reconciliation is only through March of a given year and the cashout kWh is through May of that same year, so some estimation is necessary due to timing
Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

Year of Reconciliation/Cashout:	2024	2025	2026	2027	2028	2029	PTC at 12/1/30	
SCI Excess kWh for MGs (kWh Cashed Out)			30,101,426	195,980,186	466,064,490	715,227,542		<-- Updated 8/20/25
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114	$ 0.12358	$ 0.13580	$ 0.15898	$ 0.18888	
Incremental SCI Net Metering Expense			$ 3,646,336	$ 24,219,623	$ 63,291,558	$ 113,704,729		
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 14,487,810	$ 35,061,097	$ 74,133,032	$ 124,546,203		<--cashout amount to be reflected in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each column year
	^ Actual expense	*^ Actual expense*						

NOTES:
The amount of the net metering expense that is included in the reconciliation is only through March of a given year and the cashout kWh is through May of that same year, so some estimation is necessary due to timing
Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

Year of Reconciliation/Cashout:	2024	2025	2026	2027	2028	2029	PTC at 12/1/30	
SCI Excess kWh for MGs (kWh Cashed Out)	90,905,656	95,266,876	15,050,713	97,990,093	233,032,245	357,613,771		<-- Updated 8/20/25
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114	$ 0.12250	$ 0.12855	$ 0.13920	$ 0.15095	
Incremental SCI Net Metering Expense			$ 1,823,168	$ 12,003,786	$ 29,956,761	$ 49,779,837		
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 12,664,642	$ 22,845,260	$ 40,798,235	$ 60,621,311		<--cashout amount to be reflected in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each column year
	^ Actual expense	*^ Actual expense*						

NOTES:
The amount of the net metering expense that is included in the reconciliation is only through March of a given year and the cashout kWh is through May of that same year, so some estimation is necessary due to timing
Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

PPL Electric Statement No. 15-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

REBUTTAL TESTIMONY OF
ANDREW CASTANARO
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION

PUBLIC VERSION

Topics: **Maximum Registered Peak Load**
Value of EDI Transaction Information for Default Supply and Capacity Allocations

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew Castanaro. My business address is 827 Hausman Road, Allentown, Pennsylvania 18104.

Q. By whom are you employed and in what capacity?

A. I am employed by PPL Services Corporation ("PPL Services"), an affiliate of PPL Electric Utilities Corporation ("PPL Electric" or the "Company") that provides services to PPL Electric, as the Energy Procurement Manager.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted direct testimony on behalf of the Company, PPL Electric Statement No. 15.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Office of Consumer Advocate ("OCA") Witness Zach Teti (OCA St. 6), Office of Small Business Advocate ("OSBA") Witness Mark Ewen (OSBA St. No. 1), Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Witness Patrick Cicero (CAUSE-PA St. No. 1), Customer-Generator Coalition ("CGC") Witness Guy Sharfman (CGC St. No. 1), Joint Solar Advocates ("JSA") Witnesses Kevin Lucas (JSA St. No. 1) and Justin Barnes (JSA St. No. 2), Professional Dairy Managers of Pennsylvania ("PDMP")

Witnesses James Harbach (PDMP St. No. 1) and Timothy Rensch (PDMP St. No. 2), and Walmart Inc. ("Walmart") Witness Matthew T. Lyon (Walmart St. No. 1), concerning the Company's Maximum Registered Peak Load ("MRPL") proposal, which would assign default service customers on the Generation Supply Charge ("GSC") to Rate GSC-1 and Rate GSC-2 based on their MRPL, as defined by the Company's proposed retail tariff submitted in this proceeding. I also will respond to an allegation by Retail Energy Supply Association ("RESA") witness Frank Lacey (RESA St. No. 1) about the value of Electronic Data Interchange ("EDI") on default supply costs and capacity allocations.

Q. Have you prepared any exhibits or schedules in support of your rebuttal testimony?

A. Yes. Attached to my rebuttal testimony are PPL Electric Exhibits AC-1R and AC-2R as well as PPL Electric Exhibits AC-3R and 4R (HIGHLY CONFIDENTIAL).

II. MAXIMUM REGISTERED PEAK LOAD

Q. Would you please summarize the parties' stances on the Company's MRPL proposal?

A. In this proceeding, PPL Electric's proposal has received support from the OCA, OSBA, and CAUSE-PA. (*See* OCA St. 6, p. 3; OSBA St. No. 1, pp. 4, 13-15; CAUSE-PA St. No. 1, pp. 113-15.) Meanwhile, CGC, JSA, PDMP, and Walmart have expressed opposition to the Company's proposal. (CGC St. No. 1, pp. 5-30; JSA St. No. 1, pp. 4-49; JSA St. No. 2, pp. 4-46; PDMP St. No. 1, pp. 1-10; PDMP St. No. 2, pp. 3-8; Walmart St. No. 1, pp. 19-21.) I note that CGC and JSA offer alternative modifications to the Company's proposal as well. (CGC St. No. 1, pp. 29-30; JSA St. No. 2, pp. 37-46.)

Q. Could you please summarize OCA witness Teti's support for the Company's proposal?

A. Mr. Teti believes that the MRPL will make the Company's default service procurement more efficient by reducing uncertainty around volumetric procurement and avoid shifting risk included in supply contract premiums. He further asserts that approval of the proposal would create fairness across customers and customer classes in which compensation for customer generators would not "corrupt the efficiency of the procurement process." (OCA St. 6, pp. 3-4.)

Q. Do you agree with Mr. Teti that the MRPL proposal will mitigate the need for risk premiums in default service provider contracts to account for switching risk and volumetric risk (OCA St. 6, pp. 10-11)?

A. I agree that the MRPL will temper risk premiums for switching and volumetric risk, but it will not completely eliminate them. There will still be uncertainty related to these factors, given the ability of all customers to leave and return to default service.

Q. Mr. Teti also states that he "would like to better understand the process by which capacity costs and compensation to customer-generators are recovered by PPL customers." (OCA St. 6, pp. 12-13.) He recommends that the Company provide clearer explanation of: (1) how load reduction affects PJM Interconnection LLC ("PJM") costs; (2) how customer-generators are compensated at retail rates made up of wholesale components; and (3) the option for customer-generators to participate directly in the

wholesale market instead of the retail market. (OCA St. 6, p. 4.) Could you please respond?

A. Yes, and I will respond to each of Mr. Teti's questions below:

1. Load reduction and PJM costs – It is true that distributed generation can reduce peak load. This would have the effect of lessening the amount of energy needed to be procured under default service contracts and reduce PJM capacity obligations. Capacity and ancillary costs are determined at the wholesale level and allocated to load-serving entities. The Company is not disputing that customer-generators can reduce the amount of energy and capacity to be procured for default service. This is why customer-generators are compensated through load offsets and annual cash outs. The Company's proposal is not about the value customer-generators add to the system, but rather the appropriate classification for providing default service to these customers.

2. Retail rate components – Default service rates reflect bundled wholesale procurement costs for energy, capacity, and ancillary services. When bundled, these costs represent the retail rate charged to customers who are taking default service. Customer-generators are compensated at the full retail value for their excess generation when the Company uses the bundled default service rate (i.e., the Price to Compare or PTC) to calculate the amount of the excess generation payout.

3. Direct wholesale participation – Customer-generators have a variety of avenues to sell their generation. These customer-generators are able to enter into a Wholesale Market Participation Agreement ("WMPA") with PJM to sell their generation to the market. The WMPA would also allow these customer-generators to enter into bilateral power

purchase agreements ("PPAs") at a mutually negotiated rate. These wholesale options are in addition to customer-generators shopping for generation supply with an Electric Generation Supplier ("EGS") to potentially acquire a better rate for their excess generation than what the PTC would provide.

Q. Mr. Teti further states that the Company's MRPL proposal will "not substantially" impact residential customers with distributed energy resources ("DERs"). (OCA St. 6, p. 13.) Do you agree?

A. To clarify, no residential customers would be affected because residential customer-generators' alternative energy systems cannot have a nameplate capacity greater than 50 kW and would therefore not reach the threshold established for reclassification.

Q. Could you please summarize OSBA witness Ewen's support for PPL Electric's MRPL proposal?

A. Mr. Ewen agrees that the current classification of Small C&I default service customers are disproportionately subsidizing large customer-generators that should be classified as merchant generators in the Large C&I customer class. The current classification is causing the GSC-1 default service customers to incur a higher cost burden to pay for the net metering excess generation cashouts of minimal load customers.

Q. Please summarize CAUSE-PA witness Cicero's support for the Company's MRPL proposal?

A. Mr. Cicero expresses concerns about affordability, particularly to multifamily, subsidized housing providers to low-income households, as a result of excess compensation to merchant generators. In addition, he states concern for potential impacts being spread to residential customers if more customer generators come online.

Q. Why do you think the support of OCA, OSBA, and CAUSE-PA is important when evaluating the Company's proposal?

A. The support of these organizations is critical because they represent the interests of residential, small commercial, and low-income customers. These are the groups that are most affected by changes in default service and the subsidization created by current net metering cashout practices. It is important to note that PPL Electric does not earn a profit in procuring electric generation supply to serve default service customers. The Company's interest in proposing the MRPL is to ensure fair and equitable rate design to protect Small C&I customers from adverse pricing effects due to the cash-outs for the excess generation of no-load customer-generators. The Company's proposal demonstrates its commitment to fairness, affordability, and cost causation principles, intending to limit the burden placed upon default service customers by unintended cost shifts.

Q. What is the cost of procuring the default service supply to serve customers under Rate GSC-1 as opposed to the costs of paying no-load customer-generators year-end cash-outs for their excess generation?

A. PPL Electric purchases energy, capacity, transmission, ancillary services, transmission and distribution losses, congestion management costs, Alternative Energy Credits ("AECs"), and other services or products that are required to supply default service customers through a series of full-requirements, load following contracts at wholesale market rates. These costs are recovered by the Company through the GSC-1 charged to Residential and Small C&I default service customers. The GSC-1 is a reconcilable rider mechanism as described in Section 1307(e) of the Public Utility Code. *See* 66 Pa. C.S. § 1307(e). Separately, PPL Electric compensates customer-generators participating in net metering consistent with the AEPS Act and the Commission's regulations. As such, every kWh of electricity produced by a customer-generator's system offsets one kWh of electricity used by that customer-generator during the billing period. Any excess kWh produced by the customer-generator is banked and applied to future billing periods. At the end of the PJM Planning Year (i.e., May 31 in a given year), the Company cashes out the banked kWh at the PTC. For no-load customer-generators, they have little to no load independent of the alternative energy system to offset their generation. Therefore, they bank nearly all the kWh produced by their systems, and the no-load customer-generators in the Small C&I customer class have their banked generation paid out at the Small C&I PTC rate. Critically, that PTC rate is significantly higher than the wholesale market prices that these merchant generators would otherwise receive for their generation.

Q. So, at a dollar-per-kilowatt level, is it more expensive for PPL Electric to pay for those year-end cash-outs than it is to procure default service supply?

A. Yes, undoubtedly.

Q. Why is that?

A. The Small C&I PTC at which year-end cashouts are being paid to SC&I customer generators with excess generation is significantly higher than the wholesale market prices for default service supply procurement. This is because the Small C&I PTC includes costs in addition to the cost of generation supply, including administrative costs, net metering expenses, and an amount associated with the reconciliation of over/under recovered costs. Put simply, 1 MW of net-metered generation at the bundled PTC rate is always going to be more expensive than 1 MW of generation acquired from the Company's load following contracts which were obtained through a competitive auction. This is clearly illustrated in PPL Electric Exhibit AC-2R, which shows the calculation of the PTC by line item. Procurement costs for Small C&I are included on page 5, lines 1-5. Also, page 5, lines 6 through 14 include the additional costs included in the PTC for which these customers are compensated.

Q. From your perspective, what are the goals of PPL Electric and the supporters of its MRPL proposal compared to the goals of the opponents to the proposal?

A. PPL Electric and its supporters are advocating for reforms that protect non-customer generators from no-load customer-generator customers being misclassified and ensure cost

fairness for all customers. The current structure allows large merchant generators to receive compensation for excess generation and is creating an inequitable cost burden shift for Small C&I default service customers that subsidize these generators. PPL Electric's proposal seeks to reclassify these merchant generators based on their peak demand or export peak, aligning these customers with the appropriate rate class based on their impact to the system, costs to serve load, and reducing unnecessary subsidies. This approach ensures that customer-generators are grouped with other similarly situated customers for the purpose of receiving default service.

Opponents, on the other hand, aim to maintain the status quo because it allows them to continue profiting from an inflated PTC. Their position prioritizes preserving high PTC levels to sustain merchant generator profitability, rather than focusing on least-cost, reliable service for all customers. This stance conflicts with the Commission's statutory responsibility to ensure affordability and reliability, not to guarantee profitability for merchant generators. As noted in Mr. Cicero's testimony, net metering was never intended to serve as a mechanism for large-scale merchant generation to exploit retail pricing constructs and maximize their profits. The reforms proposed by PPL Electric are designed to restore the original purpose of net metering—supporting customer-owned generation—while limiting cost shifts that harm other ratepayers.

Q. Other parties' witnesses have questioned the lawfulness of PPL Electric's MRPL proposal, arguing, among other things, that the proposal conflicts with the Alternative Energy Portfolio Standards ("AEPS") Act of 2004. Could you please respond?

A. I am advised by counsel that nothing prevents PPL Electric from appropriately classifying customers for the purpose of providing default service and that the Commission agrees. To the contrary, the Company's proposal comports with PPL Electric's legal obligations, especially its duty under the Public Utility Code to procure default service supply that is designed to ensure adequate and reliable service to customers at the least cost to those customers over time. *See* 66 Pa. C.S. § 2807(e)(3.4). In fact, the Commission approved a substantially similar proposal in UGI Utilities, Inc. - Electric Division's ("UGI Electric") most recent Default Service Plan ("DSP") proceeding that is now on appeal before the Commonwealth Court of Pennsylvania, and even more recently approved a similar proposal by Citizens' Electric Company of Lewisburg ("Citizens' Electric") in its 2025 Rate Case on January 15, 2026. In both of those decisions, the Commission rejected solar developers' legal arguments, including their claims that the companies' proposals violated the AEPS Act. For these reasons, and as will be further explained in PPL Electric's briefs, the Company's MRPL proposal not only complies with the law but is required for the Company to meet its statutory obligation to provide adequate and reliable default service to customers at the least cost over time.

Q. Multiple parties in this case and individuals who testified at the public input hearings have raised concerns about the affordability of electric bills. How will the Company's MPRL proposal help mitigate the total bill impacts on customers?

A. The Company's proposal directly addresses affordability concerns by ensuring that costs are allocated fairly and transparently. As I noted in my direct testimony, PPL Electric projects

that the annual cash-outs for the Small C&I customer class will increase from approximately $11 million as of March 31, 2025, to between $60 million and $300 million by 2029. Those increased expenses will drive up the PTC paid by all other Small C&I customers by an estimated $0.01806 per kWh to $0.0836 per kWh, respectively. Based on the average monthly usage for a Small C&I customer, those incremental increases in the PTC would equate to increases in their average monthly bills between $29.81 to as high as $174.01, respectively. By implementing objective classification criteria and reclassifying these customers to the Large C&I customer class, pursuant to the MRPL, the Commission can help ensure that Small C&I customers' bills remain more affordable by approving the MRPL proposal.

Q. Has CGC produced any information in discovery that reinforces the Company's need to implement its MRPL proposal, including the affordability concerns you have identified?

A. Yes. PPL Electric propounded discovery on CGC asking its members for information about the revenues they project to receive for each of their no-load generating facilities if PPL Electric's MRPL proposal were denied, as well as the per kWh PTC rate they would need to be profitable. Those responses reinforce PPL Electric's concerns and further support the need to implement the Company's proposal.

Indeed, attached to my rebuttal testimony are PPL Electric Exhibits AC-3R (HIGHLY CONFIDENTIAL) and AC-4R (HIGHLY CONFIDENTIAL). The former is a table summarizing the data provided by CGC in response to PPL Electric's discovery requests on

these points, and the latter contains copies of CGC's actual discovery responses that were used to complete the table. Based on those exhibits, I note the following.

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Furthermore, as noted previously, parties and members of the public have raised affordability concerns about electric rates repeatedly in this proceeding. As seen in PPL Electric Exhibit AC-2R, the Company's current Small C&I PTC is $0.12681 per kWh, which is at historically high rates. PPL Electric earns no profit on its provision of default service

and complies with its default supply procurement plan to ensure the least cost reliable and adequate supply service is provided to customers.

Conversely, the profits of CGC members and similarly-situated customer-generators are tied to the Small C&I PTC rate, as that rate determines their year-end cash-out compensation for excess generation. Therefore, they have no financial incentive to support measures that could mitigate increases in the PTC. Rather, they have every financial incentive to make the PTC increase as much as possible. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** These projects were risky investments, and PPL Electric's ratepayers should not be forced to pay increased default service rates to ensure that no-load customer-generators earn a profit on those investments. Thus, the Commission should approve PPL Electric's MRPL proposal without modification.

Q. CGC witness Sharfman alleges that "tariff structure that governs solar crediting is a key factor that drives solar development in a market," that PPL Electric's "proposed tariff changes effectively renege on the solar crediting structure that drove solar expansion in the Company's service area," and "the proposed changes will harm many GSC-1 customers by reclassifying them as GSC-2 customers, thereby greatly lowering

the revenue they currently receive for excess solar generation." (CGC St. No. 1, pp. 5-6.) Please respond.

A. PPL Electric is required to provide least-cost, reliable electricity to non-shopping customers in its service territory. *See* 66 Pa. C.S. § 2807(e)(3.2)-(3.4). It is not the Company's responsibility to ensure profits for customers through excess generation revenue. Furthermore, the Company is not changing its solar crediting structure. Customer-generators will still have their on-site load offset by their generation, and any excess generation will be paid out at the end of the year using the applicable PTC for the customer. I am advised by counsel that nothing prevents PPL Electric from appropriately classifying customers for the purpose of providing default service and that the Commission agrees. In fact, as I noted previously, the Commission approved a substantially similar proposal in UGI Electric's most recent DSP proceeding that is now on appeal before the Commonwealth Court of Pennsylvania, and even more recently approved a similar proposal by Citizens' Electric in its 2025 Rate Case.

Q. Mr. Sharfman also asserts that the "reclassification of GSC-1 customers to GSC-2 would also expose these customers to a highly volatile and unpredictable wholesale electricity market," and because these customers "likely lack the tools to analyze and mitigate the risks associated with the wholesale market[,] they may be harmed as a result." (CGC St. No. 1, p. 6; *see id.*, pp. 11-12.) Please respond.

A. Exposure to price volatility is an inherent aspect of participating in any competitive market. Additionally, in the Company's experience, no load customer-generators are sophisticated well-funded corporate entities. Their involvement in this case proves that they should have

the tools to analyze and evaluate risk. The arguments presented are around price sensitivity for the viability of future projects, which is exactly the analysis that Mr. Sharfman claims that these entities are too unsophisticated to perform.

Further, the PTC can also be volatile and can change dramatically over the expected life of the no load customer-generator projects. For example, the Small C&I PTC increased from 7.541 cents/kWh for the period 6/1/2021-11/30/2021 to 10.285 cents/kWh for the period 12/1/2021-12/31/2021, an increase of almost 40%. See PPL Electric Exhibit AC-1R for the historical PTCs. If you accept the customer-generator parties' arguments that they need to be compensated at current PTC levels to be financially viable, then if the PTC were to fall to 2021 levels, many of these projects would be in financial distress anyway. These customer-generators have already accepted the risk of PTC fluctuations and decided to proceed despite this risk.

Finally, no load customer-generators have other options than the Company's PTC. What is at issue in this case is how these customers are classified for the purposes of default service. There is nothing preventing no-load customer-generators from entering into agreements with competitive suppliers to obtain compensation that is acceptable to them.

Q. Do you agree with Mr. Sharfman that the Company's "proposal could materially hinder solar development in PPL's service area since planned GSC-1 solar installs may be canceled if the array is no longer economically viable under GSC-2" and that those developers may focus on other utilities' service territories instead (CGC St. No. 1, p. 6.)?

A. No, the proposal may alter the economics of no-load customer-generator projects, but it will not have a material impact on overall solar installations. Customers remaining in the GSC-1 class will be evaluating economics under the same conditions as they currently do. As mentioned previously, there is also no requirement that these customers take default service, and they are free to shop if they do not think GSC-2 is appropriately compensating them for their excess generation. In addition to the retail net-metering compensation model, these customers can also sell their generation through the PJM markets.

Q. Mr. Sharfman also alleges that the Company's proposal artificially inflates the MRPL by bifurcating the MRPL derivation from the PJM ICAP and incorporating the customer-generator's nameplate capacity. (CGC St. No. 1, pp. 14-15.) Do you agree?

A. No, I do not agree with Mr. Sharfman's claim. The MRPL calculation is not intended to identify or assign PJM capacity obligations; rather, it is solely used to determine the appropriate default service rate class for customer-generators. PJM ICAP values serve a different purpose related to wholesale capacity obligations, which are not relevant to retail rate classification. Including nameplate capacity in the MRPL derivation ensures that customers with significant generation capability are classified correctly for pricing purposes, reflecting their potential impact on procurement and settlement processes.

Q. Mr. Sharfman contends that the Company's filings confirm that DERs reduce, rather than increase, customer demand and system load and argues that a resource that "reduces net load, improves demand forecasting, and mitigates load masking cannot, as

a matter of sound electric system analytics or cost-causation principles, be recharacterized as incremental customer demand." (CGC St. No. 1, p. 15.) Please respond.

A. The Company's focus is on the proper classification of customers, not on redefining system load or customer demand metrics. The purpose of my testimony is to ensure accurate categorization of customers within customer classes, independent of any demand forecasting considerations. Furthermore, to the extent that Mr. Sharfman is contending that customer-generators should be paid a premium for these alleged benefits, the PTC that is used to pay them today and the PTC that will be paid under PPL Electric's MRPL proposal is a premium, given that it is higher than the wholesale rate that they otherwise would be paid if net metering did not exist.

Q. Is Mr. Sharfman correct that under PPL Electric's proposal, "many GSC-1 customer-generators would be reclassified as GSC-2" (CGC St. No. 1, p. 16)?

A. No, of the approximately 1,250 commercial customer-generator installations on the system as of January 5, 2026, only 18 would be reclassified from GSC-1 to GSC-2 if the Company's MRPL proposal is approved.

Q. Mr. Sharfman raises a concern that "GSC-2 excess generation customers only receive the energy charge as a credit," while "GSC-1 customers receive the full PPL PTC which includes capacity, transmission, and ancillary services, ISO and administrative fees, and other attributes in addition to energy." (CGC St. No. 1, pp. 16-17.) Please respond.

A. I disagree with Mr. Sharfman's statement. Customer-generators being paid out at the GSC-2 PTC also includes transmission costs and administrative costs in addition to the energy costs.

Q. Do you agree with Mr. Sharfman that PPL Electric's MRPL proposal would "stand in opposition to Pennsylvania's AEPS compliance path" (CGC St. No. 1, p. 18)?

A. No, because Mr. Sharfman grossly oversimplifies the goals of the AEPS Act. According to Mr. Sharfman, the sole intent of the AEPS Act is to increase renewable generation in Pennsylvania. I am advised by counsel that the Alternative Energy Portfolio Standards seek to ensure that "a certain amount of energy sold from alternative energy sources is included as part of the sources of electric generation by electric utilities within this Commonwealth." 73 Pa. C.S. § 1648.2. Despite Mr. Sharfman's assertion, the goal of the AEPS Act was never to increase renewable generation in Pennsylvania regardless of cost or impact to the other customers. Rather, by setting specific targets, it was always the intent of the AEPS Act to promote alternative energy sources while balancing costs to other customers.

Q. Do you agree with Mr. Sharfman that "[o]utside of the fact that a solar array generates power and load consumes it, there is no reason to suggest that any industrial load would behave in the same manner as a solar generator that depends on hours of sunlight" (CGC St. No. 1, p. 19)?

A. Mr. Sharfman's contention lacks merit because all rate classes include users with dissimilar usage patterns. According to Mr. Sharfman's logic, no-load customer-generators should not be in the Small C&I class either as their operation has nothing in common with the usage of

patterns of other Small C&I customers. Ultimately, the question is whether the customer classification is reasonable. It is the Company's position that a no-load customer-generator with 3 MW (or 3,000 kW) of export is more akin to a large industrial user than a Small C&I customer with less than 100 kW of demand, so it is reasonable to group those no-load customer-generators with Large C&I default service customers as opposed to Small C&I default service customers.

Q. Mr. Sharfman points to issues that occurred in Texas due to Winter Storm Uri in February 2021, when residential customers were enrolled in rates that were tied to the ERCOT LMP market, noting that the rates spiked for those customers and that Texas banned residential customers from accessing real-time rates as a result. (CGC St. No. 1, pp. 20-21.) Do you think this example is relevant to the MRPL proposal?

A. The volatility that Mr. Sharfman references is a market function and would compensate the no load customer-generators more during times of grid stress. The Winter Storm Uri example proves PPL Electric's position that the GSC-2 rate will more accurately compensate no-load customer-generators for the value they are providing to the grid.

Q. Why does Mr. Sharfman claim that your testimony about the harm to non-customer-generators in GSC-1 is hard to follow?

A. He alleges that "[u]tility rate classes are generally set based on electric demand and usage pattern. It is not clear why a GSC-1 customer that behaves nothing like a GSC-2 customer should be forced to take service under GSC-2 just because they have a solar generator on-site

that produces more than 100kW of electricity." (CGC St. No. 1, p. 24.) Further, he reviews my assertion that GSC-1 customers pay the "financial burden" for projects is puzzling, as the installation and maintenance of solar generation is paid for by the customer generator and solar company. (*Id.*) The MWh associated with solar generation offsets the generation PPL Electric would be forced to purchase through load following contracts otherwise, so aside from the fact that offsetting market purchased generation was the goal of AEPS to begin with, the MWh generated by GSC-1 customer generators reduce the MWh PPL Electric must procure to supply the GSC-1 class. (*Id.*) As such, Mr. Sharfman expects the GSC-1 PTC to decline over time, which benefits the GSC-1 class. (*Id.*)

Q. Is Mr. Sharfman's position correct?

A. No. While the customer may not "behave" like a traditional GSC-2 load in terms of consumption, their generation capability creates planning and cost implications similar to those in GSC-2. Likewise, no-load customer-generators do not behave like other GSC-1 customers either. If anything, Mr. Sharfman is arguing that no-load customer-generators should be in a separate default service rate class by themselves. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

Q. Please also respond to Mr. Sharfman's claim that "PPL's assertion that existing GSC-1 customers impose a cost burden on other customers is also inconsistent with the Company's own evidence regarding the system-level benefits of distributed energy resources ('DERs')." (CGC St. No. 1, p. 25.)

A. PPL Electric's assertion regarding cost burden is based on the fact that existing GSC-1 customers with large-scale DERs receive full retail PTC payments for excess generation that is far above the wholesale market value of that energy. These inflated payouts are recovered from other default service customers, creating a direct cost shift. System-level benefits are real but generalized. They accrue to the grid as a whole and do not offset the incremental financial obligations imposed on non-participating customers under current tariff rules. Cost-causation principles require that compensation reflect the actual avoided costs and reliability impacts, not unrelated benefits. Therefore, recognizing DER benefits does not eliminate the need to address inequitable cost recovery and ensure that pricing aligns with market fundamentals. Additionally, the Company's proposal continues to compensate no-load customer-generators for their benefits in a manner consistent with the AEPS Act.

Q. Please address Mr. Sharfman's claims that PPL Electric has not provided any "empirical" evidence that its current tariff misaligns cost responsibility and that no-load customer-generators create a cost burden comparable to large industrial customers. (CGC St. No. 1, pp. 25-26.)

A. Mr. Sharfman confuses the Company's position that no-load customer-generators will drastically increase the cost of default service for Small C&I customers, with the costs that

these customer-generators will place on the distribution system. I have provided evidence that without the MRPL proposal the Small C&I PTC will continue to increase to unaffordable levels. I do not agree with Mr. Sharfman's statements about the benefits that no-load customer-generators will provide, and regardless, those alleged benefits are irrelevant to deciding whether to approve the Company's MRPL proposal.

Q. Mr. Sharfman also attempts to criticize your direct testimony by claiming that you provided no evidence that Small C&I customers suffer higher default-service procurement costs due to net metering exports and that you provided no study comparing the cost to serve a 3 MW net metered facility to a 3 MW load consistent industrial facility. (CGC St. No. 1, pp. 26-27.) Please respond.

A. Excess generation from net-metered customers is cashed out at the full retail PTC, which far exceeds the wholesale cost PPL Electric pays for default supply. This disparity creates incremental costs that must be recovered from other customers in the same class, regardless of facility size. This was demonstrated in the analysis provided in my direct testimony, projecting the increase in net metering cashouts and the impact on the Small C&I PTC, which is imposed as a cost burden to default service customers. The comparison to the cost to serve a 3 MW load customer is irrelevant because the Company is not proposing to change these customers' distribution rate schedule.

Q. Mr. Sharfman also rejects PPL Electric's evidence that the PTC could reach $300 per MWh by 2028, pointing to his Exhibit CGC 3.0 that provides Amerex peak forwards

for the PJM PPL zone and estimated GSC-1 PTC values based on the Amerex forwards. (CGC St. No. 1, pp. 27-28.) Please respond.

A. The analysis performed by the Company was not to be used as a PTC price forecast of an expected dollar per MWh value, but rather to show the directional and magnitude impact of the increase in net metering expense related to excess generation annual cashouts while holding all other PTC inputs constant. In addition, the analysis does not suggest a $300/MWh PTC in any scenario in 2028. The analysis shows a PTC of $150/MWh in the highest case scenario for 2028. The analysis included in the PTC the Transmission Service Charge ("TSC") and the cost of the full-requirements, load following contracts, which include energy, capacity, ancillary services, AECs, and other costs. In fact, the average full requirements price in the Company's analysis is $0.08064/kWh, and is almost the same as the average Amerex forward prices in Exhibit CGC 3.0 of $0.07894/kWh, which do not include the other aforementioned cost components included in the full requirements contracts. However, the power forwards referenced in Exhibit CGC 3.0 only include the energy component in their forecast and do not account for the additional cost elements. The GSC-1 rate also includes administrative costs, net metering costs, and the impact of reconciliation in addition to pure generation supply costs, as shown in PPL Electric Exhibit AC-2R.

Q. If the Commission adopts PPL Electric's MRPL proposal, Mr. Sharfman recommends that the Commission apply the MRPL to new customer-generators only, essentially grandfathering in the existing customer-generators. (CGC St. No. 1, pp. 29-30.) JSA Witness Barnes makes a similar recommendation that it is necessary to establish "legacy

rights" due to the financial investment made by customer-generators and the principle of "gradualism" to prevent "rate shock." (JSA St. No. 2, pp. 32-37.) Do you agree with these recommendations?

A. No, I do not. Grandfathering customer-generators would undermine cost equity and non-customer generators will continue to bear disproportionate costs. The Commission should apply the MRPL proposal uniformly to all customer-generators to ensure fairness for all customers. The Company changes its rates from time to time without grandfathering for other customers. Also, as explained in Mr. Olsen's rebuttal testimony (PPL Electric St. No. 14-R), it could have been anticipated that the compensation model may change for no load customer-generators which does not support these grandfathering proposals.

Additionally, Mr. Sharfman errs in relying on the stranded cost recovery that was permitted for electric utilities as part of restructuring of the retail electric market in Pennsylvania. (*See* CGC St. No. 1, p. 29.) Electric utilities, unlike these solar developers, are guaranteed an opportunity to earn a just and reasonable return on their investments. In exchange, the electric utilities' rates and services are regulated by the Commission. *See, e.g.*, 66 Pa. C.S. §§ 1301, 1501. I am advised by counsel that is why the General Assembly needed to ensure stranded cost recovery as part of the Electricity Generation Customer Choice and Competition Act ("Competition Act"). *See, e.g.*, 66 Pa. C.S. §§ 2803, 2804(13)-(14), 2808. Solar developers, however, operate in a competitive, unregulated market, and the Commission does not regulate their service or the rates they charge. Thus, in exchange, they are not guaranteed and should not be guaranteed any return on their investments, particularly when the Company's customers would be footing the bill for the developers' risky investments.

Q. JSA witness Barnes also contends that the "establishment of legacy rights for Existing facilities" is "consistent with [his] understanding of the Commission's determination in the UGI Proceeding and related default service plan," on the grounds that no existing customer-generators were affected by UGI Electric's change in customer classification. (JSA St. No. 2, p. 40.) Please respond.

A. Although no existing facilities were affected by the Commission's ruling in the UGI Electric Default Service Plan V ("DSP V") proceeding, Penn Renewables LLC ("Penn Renewables") had 12 solar array projects in development in UGI Electric's service territory that would be affected by UGI Electric's Supply Peak Load Impact ("SPLI") proposal in that proceeding. *See Petition of UGI Utilities, Inc. - Electric Division for Approval of a Default Service Plan for the Period of June 1, 2025 through May 31, 2029,* Docket Nos. P-2024-3049343, *et al.*, p. 24 (Order entered Feb. 20, 2025). Penn Renewables opposed the SPLI proposal and has continued to dispute the Commission's approval of that proposal on appeal to the Commonwealth Court.

Moreover, the Commission recently approved the Joint Petition for Approval of the Non-Unanimous Settlement in Citizens' Electric's 2025 Rate Case, as modified by the Commission. *See Pa. PUC v. Citizens' Electric Co.*, Docket Nos. R-2025-3054394, *et al.*, pp. 68-76 (Order entered Jan. 15, 2026) ("*Citizens' Electric*"). In that proceeding, several solar developers challenged Citizens' Electric's billing demand proposal, which is similar to UGI Electric's DSP V customer classification and PPL Electric's MRPL proposal. Notably, one of the solar developers' witnesses was JSA witness Lucas, who testified that "[t]he

practical effect" of Citizens' Electric's proposal "is that the 13 customer-generators on the GLP-1 tariff will see a massive increase in distribution costs, while the 1,124 non-customer generators on the GLP-1 tariff will see a non-trivial distribution bill reduction." (Solar Projects Main Brief, *Pa. PUC v. Citizens' Electric Co.*, Docket Nos. R-2025-3054394, *et al.*, p. 27) (quoting Solar Projects' St. No. 2-SR, p. 21).) In the end, the Commission rejected the Solar Projects' arguments and approved Citizens' Electric's billing demand proposal. Thus, the Citizens' Electric case directly undercuts Mr. Barnes's claim that the establishment of legacy rights may be supported by the Commission.

Q. Do you have any other concerns with JSA Witness Barnes's proposal to establish legacy rights for existing facilities and transition facilities?

A. Yes. Foremost, PPL Electric maintains that its MRPL proposal should be approved in full by the Commission, and nothing presented by the other parties' witnesses warrants deviating from the Commission's well-established precedent in the UGI Electric DSP V case and in the very recent Citizens' Electric 2025 Rate Case. Across the Commonwealth, utilities are sounding the alarm about the adverse impact that the no-load customer-generators are having and are projected to have on customers' default service rates. These concerns are heightened in PPL Electric's service territory, where the amount of existing and projected no-load customer-generators outpace peer electric utilities, including UGI Electric and Citizens' Electric, whose similar proposals to deal with this problem were approved by the Commission. No legacy rights were established for existing or transition facilities in those

cases, and none should be established here either, to ensure that non-customer-generators are not unduly harmed.

Moreover, all no-load customer generators impact the default service rates for non-customer generator customers, due to the increased costs incurred with compensating them for their excess generation as opposed to procuring cheaper supply on the wholesale market. Grandfathering any customer-generators would undermine cost equity, as non-customer generators would continue to bear disproportionate costs. The Commission should apply the MRPL proposal uniformly to all customer-generators to ensure fairness for all customers.

In addition, Mr. Barnes's alternative proposal has multiple issues. Mr. Barnes even highlights one of them in his direct testimony, as he states, "I appreciate that my proposal would not allow the Commission or PPL to know the full volume of Transition Facilities that may qualify for legacy rights in advance, prior to the election process." (JSA St. No. 2, p. 42.) Therefore, he offers that "the PaPUC could establish a maximum volume of project MWs in its final order in this case," which could be used to determine which transition facilities can qualify for legacy rights depending on the date that the applicant "executed the NoCI." (JSA St. No. 2, p. 42.) He fails to specify, however, what the maximum volume of project MWs would be under his proposal. Furthermore, there are numerous problems with the AEC conveyance aspect of his proposal, including, but not limited to, necessary modifications to PPL Electric's existing DSP Plan that would need to be approved by the Commission. Yet, Mr. Barnes's proposal envisions PPL Electric sending notices to transition facilities within 45 days of the Commission's approval of the compliance tariff supplement. Based on my

experience, there is no practical way for PPL Electric to petition for and receive approval of modifications to its DSP Plan in that timeframe.

On top of that, Mr. Barnes's proposed AEC transfer requirement is unnecessary, impractical, and inconsistent with existing AEPS compliance mechanisms. Mr. Barnes notes that his proposal would require the Commission to "establish a proxy AEC price for this transaction since in reality the AECs [would be] conveyed to PPL at a nominal zero cost." (JSA St. No. 2, p. 44.) Determining a proxy AEC price would require ongoing regulatory oversight and introduce complexity without delivering meaningful benefits. PPL Electric already satisfies AEPS obligations through its DSP procurement plan, making this proposal redundant. Moreover, compelling customers to transfer AECs without compensation could undermine incentives for distributed generation and create administrative burdens that are outside the scope of this proceeding.

Additionally, Mr. Barnes's proposal appears to contemplate subsidization by residential customers of small commercial customers' default service costs. On page 44 of his direct testimony, he states, "In other words, residential customers would pay for these AECs, the same as they would if PPL secured them through an RFP, and the resulting revenue would benefit the small commercial GSC-1 rate class." (JSA St. No. 2, p. 44.)

Mr. Barnes also fails to account for the time and expense that PPL Electric would need to devote to contracting individually with each of these transition facilities agreeing to convey their AECs to the Company, along with the time and expense needed to enforce those contracts if the facilities fail to timely convey their AECs to PPL Electric.

Finally, while Mr. Barnes cites Section 75.14(d) of the Commission's regulations as

support for his AEC conveyance proposal, he overlooks how the regulation contemplates that an EDC may need to "supply additional metering equipment" in order "to qualify the alternative energy credit." *Id.* The costs for additional metering equipment must be incurred at "the EDC's expense" under the regulation. *Id.* If the Company incurs costs additional metering costs would be passed onto ratepayers and are not factored into Mr. Barnes's analysis. Thus, Mr. Barnes's proposed alternative has too many unanswered questions to warrant further consideration.

Q. JSA witness Lucas opposes the Company's MRPL proposal and asserts that the Company has not sufficiently demonstrated the need for the proposal. (JSA St. No. 1, pp. 6-7.) As such, he recommends that the Commission reject the MRPL proposal. (JSA St. No. 1, p. 7.) What are some arguments that Mr. Lucas raises in support of his position?

A. He argues that the Company's proposal is unsupported, claiming that PPL Electric has not shown that front-of-the-meter distributed generation causes cost shifts or grid stress. He further asserts that the Company's "all-else-equal" analysis is flawed because it assumes purchasing more energy than needed. He identifies four alleged errors in the Company's cost-shift analysis: incorrect cancellation-rate assumptions, overstated generation forecasts, use of constant procurement costs, and failure to account for benefits from FTM DG. According to Mr. Lucas, these issues render the Company's analyses inconsistent with real-world procurement practices. (JSA St. No. 1, p. 6.)

Moreover, he asserts that the Company's testimony conflicts with its discovery responses, which he claims show that PPL Electric's distribution system can already accommodate FTM DG power flows and that any required upgrades are fully paid by customer-generators. He also argues that using MRPL is an inappropriate metric for assigning customers to GSC-1 or GSC-2, and contends that relying on the highest 15-minute annual load—rather than PJM peak-based measures tied to capacity costs—violates fundamental cost-causation principles. (*Id.*)

Q. Do you have any initial observations about the use of the term "FTM DG"?

A. Yes. FTM DG necessarily implies that the generation facility is not located behind the meter and, therefore, not being used to offset load at the customer location. In that respect, FTM DG is no different than any other generation facility that interconnects directly with an electric system. That only lends further support to classifying them in accordance with the proposed MRPL. They should not be treated the same as behind-the-meter generation because they are different.

Q. Do you have any other initial observations about Mr. Lucas's testimony?

A. Yes. As noted above, the Commission recently approved a proposal by Citizens' Electric that is similar to PPL Electric's MRPL on January 15, 2026, in Citizens' Electric's 2025 Rate Case. I note that Mr. Lucas testified on behalf of the "Solar Projects" in opposition to Citizens' Electric's proposal in that proceeding and raised arguments similar to the ones he offers in this proceeding. Ultimately, the Commission rejected the Solar Projects' arguments and

approved Citizens' Electric's billing demand proposal. From my perspective, the Commission should follow suit here and reject Mr. Lucas's claims.

Q. Please respond to Mr. Lucas's claim that the Company's proposal is poorly supported and that its argument that these no-load customer-generators cause a cost shift to non-customer-generators is not supported. (JSA St. No. 1, pp. 6, 17, 48-49.)

A. The Company's proposal addresses a real and measurable cost shift. Even fellow JSA witness Barnes acknowledges that the value of AECs must be considered to offset the gap. (*See* JSA St. No. 2, p. 42.) Mr. Barnes's testimony demonstrates that without incorporating AEC value, there is indeed a shortfall, or that a cost shift exists. The need to rely on AECs to "make up the gap" is an implicit admission that the current structure does not fully recover costs from customer-generators. This supports PPL Electric's position that the existing framework is inadequate and requires reform.

Q. Do you agree with Mr. Lucas you presented an "all else equal" analysis that results in the purchase of two units of energy to serve one unit of load (JSA St. No. 1, pp. 6, 44-45, 48-49)?

A. No, I do not agree with Mr. Lucas's characterization. The Company's analysis was intended to isolate the direction and magnitude of net metering expenses related to excess generation compensation. Although additional FTM DG could reduce overall supply procurement, other factors such as growing demand or customer switching could increase procurement requirements and offset the impact of FTM DG excess generation. For this reason, the

Company kept the other variables constant in its analysis. This approach ensures clarity in evaluating the incremental cost impact and counters the assertion that the analysis results in purchasing two units of energy to serve one unit of load.

Q. Mr. Lucas asserts that the Company's customer classification methodology runs contrary to cost causation principles and that NCP demand should be used in "extremely limited cases" in cost of service and rate design. (JSA St. No. 1, pp. 22, 33-36.) Please respond.

A. Mr. Lucas' analysis relies on the cost to serve no-load customer-generators from a distribution perspective and ignores the cost to serve these customers from a default service perspective. Additionally, in rate design the Company must consider equitably serving the entire class, not just one set of customers to the detriment of others. The MRPL proposal is intended to classify the large no-load customer-generators with similarly situated Large C&I customers for the purposes of default service. As such, the MRPL proposal prevents Small C&I customers from unduly subsidizing large industrial scale no load customer-generators. The Commission recently recognized the importance of eliminating that subsidy in the recent Citizens' Electric 2025 Rate Case, where the Commission cited Section 2807(e)(7) of the Public Utility Code and explained that the statute "prohibits a utility from charging default service rates to one class that subsidize the costs for other customer classes." *Citizens' Electric*, p. 71. Importantly, "Citizens' proposed new definition for Billing Demand," which is similar to PPL Electric's MRPL proposal, "offers a solution to the subsidization issue posed by large customer-generators." *Id.*

Q. Mr. Lucas asserts that PPL Electric treats "FTM DG customers as 'small' for purposes of their distribution rate as a customer, but inconsistently characterizes these same customers as 'large' for purposes of compensation for excess generation from their alternative energy systems." (JSA St. No. 1, p. 24.) Do you believe that such a criticism has merit?

A. No, and this is no different than what the Company does today. There are GS-3 customers with peak demands above and below 100 MW. These customers are segregated as Large C&I and Small C&I for default service purposes despite being in the same distribution rate schedule. Providing customers default service is fundamentally different than providing distribution service and it is reasonable to have different classifications for these two distinct services.

Q. Do you agree with the alleged four problems that Mr. Lucas identifies with respect to PPL Electric's analysis of the projected costs to be incurred by Rate GSC-1 non-customer-generators if the Company's proposal is denied (JSA St. No. 1, pp. 38-48)?

A. No.

Q. Why is that?

A. The first problem Mr. Lucas identifies is an error in the cancellation rate assumptions, particularly the 36% cancellation rate scenario. However, the 36% cancellation rate is the actual cancellation rate and is used as the base case, which essentially captures the cancelled

projects and therefore acts as 0% incremental cancellations. Next is an alleged overestimation of generation from FTM DG projects. The Company maintains that it used appropriate estimates for the amount of generation anticipated. Yet, even if it overestimated the amount of generation from no load customer-generators, it would only lessen the magnitude of the cross-subsidization, not negate the fact that it is occurring. The third issue identified is the use of constant energy procurement costs. The Company's analysis was intended to isolate the directionality and magnitude impact of one net metering expenses related to excess generation compensation. Although the addition of more FTM DG could reduce the overall supply procurement, there could be more load added to the procurement as a result of growing demand or customer switching, which would offset the FTM DG excess generation. Therefore, the Company kept the procurement cost variable constant. Finally, Mr. Lucas alleges the Company fails to recognize any benefits from FTM DG projects. As I addressed with the third concern, inputs were kept constant to isolate the impact of one variable and that although FTM DG could reduce forecasted peaks, other market factors, such as higher than projected peaks or FTM DG not being available during those peaks, could offset those benefits and were therefore not included.

Additionally, while the cost impact to the Small C&I default service rate class caused the Company to evaluate its classification of default service customers, the inclusion of no-load customer-generators would be appropriate even if the projected projects do not materialize. A 3-MW no-load customer-generator should be in the GSC-2 rate class regardless of how many of these kinds of customer-generators exist.

Q. JSA witness Barnes also testifies about the Company's MRPL proposal and presents an alternative to addressing the GSC-1 rate impacts due to FTM DG. (JSA St. No. 2, p. 4.) Could you please summarize his position and recommendation?

A. Mr. Barnes proposes three ways to protect GSC-1 customers and FTM DG owners: (1) reflect the value of excess NEM generation in GSC-1 load calculations; (2) adjust the GSC-2 rate to make excess-generation compensation cost-based; and (3) grant legacy rights to certain existing or advanced projects. He recommends allowing negative peak loads to reduce capacity and transmission allocations, revising GSC-2 compensation to include credits for negative peaks, and establishing legacy rights for operational, under-construction, or qualifying planned projects—subject in some cases to AEC transfers and additional deposit requirements. (JSA St. No. 1, p. 4.)

Q. Do you have any initial observations about Mr. Barnes's direct testimony?

A. Yes, Mr. Barnes appears to concede, unlike his fellow JSA witness, Mr. Lucas, that there is a cost shift to non-customer-generators in Rate GSC-1 due to no-load customer-generators. In fact, even under Mr. Barnes's assumptions and calculations, he admits that there is a "small gap between the market-based cost-savings value of FTM DG excess generation and the GSC-1 cash-out rate if AEC value is excluded." (JSA St. No. 2, p. 21.) That "small gap" is evidence of such a cost shift. As a result, he puts forward an AEC conveyance proposal to "bridge the 'value gap' between the GSC-1 excess generation cash-out rate and the cost reductions that excess generation produces for default service (inclusive of transmission)." (JSA St. No. 1,

pp. 42-43.) From that standpoint, it appears that the JSA witnesses' positions on whether a cost shift exists are inconsistent.

Q. Do you believe that Mr. Barnes accurately defines the "problem" that PPL Electric's proposal is intended to address (JSA St. No. 2, pp. 7-9)?

A. Mr. Barnes' characterization of the "problem" PPL Electric's proposal seeks to address does not accurately reflect the Company's intent. His framing centers on cost allocation and compensation for excess generation. The purpose of the proposal is to ensure that customers are classified into the appropriate rate schedules based on objective, measurable criteria, such as MRPL, rather than subjective interpretations of system economics. This approach promotes fairness, consistency, and transparency in rate design. It is not intended to redefine cost causation principles or alter demand forecasting methodologies, but to maintain clear and equitable standards for rate classification.

Q. Do you agree with Mr. Barnes that the Company's evaluation of how net metering excess generation affects generation supply and transmission costs is "incomplete and consequently biased," as it "fails to reflect that excess generation produces actual and readily quantifiable cost reductions that offset those costs" (JSA St. No. 2, pp. 10-11)?

A. No, I do not agree with Mr. Barnes' characterization. The Company's evaluation appropriately focuses on cost causation and PPL Electric's obligations in procuring capacity and transmission services to maintain reliable electric service for all customers. While excess generation may provide some energy-related benefits, those benefits do not eliminate the fixed

costs associated with capacity and transmission that remain necessary regardless of distributed generation output. The Small C&I customers who are paying higher default service costs do not realize the alleged benefits that Mr. Barnes discusses in his testimony.

Q. Mr. Barnes also criticizes the Company's practice of assigning zero load instead of negative load and argues that "nothing" in PPL Electric's Attachment M-2 of its OATT "precludes a customer from being designated with a negative PLC" and that nothing in the broader PJM rules precludes it either, pointing to ComEd receiving approval to use negative PLCs for NEM and community solar. (JSA St. No. 2, pp. 11-17.) Do you agree?

A. No, I do not agree with Mr. Barnes' assertion. While PJM rules do not explicitly prohibit negative PLCs, the Company's approach of assigning zero load is consistent with PJM's established methodology and the principles underlying capacity obligations. If negative tags are established, the costs would increase for all non-generating customers because the costs are still scaled to a single peak value. Importantly, the comparison to ComEd is not appropriate. In Illinois, the Illinois Power Agency ("IPA"), not the individual electric distribution companies ("EDCs"), is responsible for procuring supply to serve default service customers. This means ComEd does not procure or settle its own default supply in the PJM markets. As a result, ComEd does not carry the market exposure or settlement responsibility associated with the capacity and energy obligations tied to its customers' PLCs. Instead, the IPA, as the centralized state procurement entity, absorbs the risk associated with any volatility or distortions in PLC assignments, including negative PLC values.

This structure fundamentally differs from PPL Electric's role. PPL Electric is directly responsible for procuring full-requirements supply, managing PJM settlements, and carrying the financial and operational risk tied to PLC assignments for customers served under the Price-to-Compare ("PTC"). Assigning negative PLCs would artificially reduce the Company's load obligation in a way that does not reflect actual system capacity needs and would shift risk and cost inequities onto other customers. By contrast, PJM's PLC methodology is designed to measure a customer's contribution to system peak load. Setting PLCs to zero for customers whose net metering production exceeds their load preserves that principle without creating distortions in PJM settlement processes. Negative PLCs would improperly imply that a customer provides a capacity benefit to the system, even though behind-the-meter generation is not dispatchable by PJM and does not reduce PJM's forward capacity requirements. For these reasons, assigning a zero PLC aligns with PJM's framework, avoids introducing risks and settlement distortions for default service procurement, and is consistent with how capacity responsibilities function in jurisdictions, like Pennsylvania, where EDCs, not state agencies, procure and settle default supply.

Lastly, it is my understanding that the negative PLCs that ComEd use are for the purposes of incentivizing certain large customer renewable investments. The negative PLCs are part of a coordinated state renewable policy. Additionally, the negative PLCs are not used to settle the PJM market for capacity or transmission service. ComEd and PPL Electric both do not allow negative PLCs for capacity or transmission purposes. Furthermore, because Pennsylvania does not have a similar large customer renewables program like Illinois, it

would be inappropriate to copy the negative PLC model. As such, Mr. Barnes's reliance on the IPA's treatment of negative PLCs is misplaced.

Q. Mr. Barnes presents analyses for assessing the value of net metering excess generation (including his use of Demand Induced Market Price Effects ("DRIPE") and notes that he used two scenarios: one based on how PPL Electric presently accounts for NEM excess generation by small commercial GSC-1 customers in its default service supply plan, and a second based on a wholesale market value approach that reflects the value of NEM excess generation for a wholesale generation supplier that serves small commercial GSC-1 loads. (JSA St. No. 2, pp. 19-31.) Do you have any issues with Mr. Barnes's analyses?

A. Mr. Barnes' analyses, including his use of DRIPE and wholesale market valuation scenarios, are not relevant to this issue. These approaches introduce speculative assumptions and wholesale market constructs that fall outside the scope of this proceeding. The Company's proposal is focused on ensuring accurate and equitable classification of customers into rate schedules based on objective criteria, not on recalculating compensation for excess generation or embedding capacity values into retail rates. Accordingly, Mr. Barnes's valuation exercises should not influence the Commission's determination in this matter.

Q. Mr. Barnes also argues that the generation capacity portion of supply costs should be included in the GSC-2 NEM cash-out rate and explains how that would function, arguing that doing so would not involve "any significant additional complexities," as

"PPL is already measuring PJM 5CP demands for the purpose of establishing customer capacity charges." (JSA St. No. 2, pp. 29-32.) Do you agree?

A. No, I do not agree with Mr. Barnes' position. Including the generation capacity portion of supply costs in the GSC-2 NEM cashout rate would effectively compensate customer-generators for capacity when their capacity obligation is zero. While PPL Electric does measure PJM 5CP demands, those measurements are used solely to allocate capacity obligations for load-serving entities, not to calculate retail credits for excess generation. Incorporating capacity value into cashout rates would misalign with cost-causation principles and introduce unnecessary complexity into billing and settlement processes, contrary to Mr. Barnes' assertion.

Q. Mr. Harbach also claims that the Alternative Energy Portfolio Standards ("AEPS") Act does not authorize utilities or the Commission to modify procurement classes or rate classes in order to reduce the compensation to customer generators to offset the alleged cost of net metering. (PDMP St. No. 1, p. 9.) He further asserts that the Commission and PPL Electric should ensure that all elements of default service, not just the per kWh charge. (PDMP St. No. 1, p. 10.) Please respond.

A. As I explained previously, the Commission has rejected these legal arguments in the UGI Electric and Citizens' Electric cases. I am advised by counsel that PPL Electric's proposal comports with the AEPS Act and that the Company's proposal would continue to compensate customer-generators in compliance with the AEPS Act and the Commission's regulations. These legal issues will be further addressed in PPL Electric's briefs.

Q. PDMP witness Rensch alleges that without net metering compensation at the present level, digester projects would not be viable. (PDMP St. No. 2, p. 6.) He then presents a series of possible ramifications due to making digesters uneconomic. (PDMP St. No. 2, pp. 7-8.) Please respond.

A. The viability of digester projects and the broader policy implications raised by Mr. Rensch are outside the scope of designing default service rates. While these concerns are legitimate, they are more appropriately addressed through other mechanisms, such as environmental and energy policy frameworks administered by agencies like the Pennsylvania Department of Environmental Protection ("DEP"). The purpose of this case is to ensure fair and accurate rate design for default service, not to resolve issues related to renewable project economics or environmental compliance.

Q. Walmart witness Lyon recommends that the Commission reject the Company's MRPL proposal because it would "abruptly…shift customer-generators above 100kW to hourly LMP-based kWh generation valuation" and change project value propositions and "disincentivize generation in PPL territory when capacity markets are seeing extremely high prices and forecasts are trending toward increasing demand." (Walmart St. No. 1, p. 21.) Do you agree?

A. As I have explained previously, PPL Electric's proposal would properly classify no-load customer-generators and ensure that the Company can meet its obligations under the Public Utility Code to procure reasonable and adequate default service supply at the least cost to

customers over time. Furthermore, the Company's analyses show that without its MRPL proposal being approved, the Small C&I PTC rate will increase significantly. Also, only 18 existing customer-generators would be reclassified from GSC-1 to GSC-2 if the Company's proposal is approved.

Q. Do you agree with Mr. Lyon's claim that Pennsylvania does not have an over-supply of generation that could justify disincentivizing onsite solar development (Walmart St. No. 1, p. 20)?

A. No, I do not agree with Mr. Lyon's claim. The Company's proposal is not predicated on whether Pennsylvania has an over-supply of generation, nor is it intended to disincentivize onsite solar development. The purpose of the MRPL approach is to ensure accurate and equitable classification of customers into appropriate default service rate classes based on objective criteria. This methodology aligns pricing with actual market conditions and cost-causation principles, promoting fairness across all customer groups. Broader questions regarding generation adequacy and renewable energy incentives fall under state energy policy and other regulatory programs, not the design of default service rates.

Q. In alleged support of his opposition to PPL Electric's MRPL proposal, Mr. Lyon asserts that "Monitoring Analytics and PJM…analyses have documented tightening fundamentals, price signals of scarcity in recent capacity auctions, and scenarios where local constraints or retirements could cause shortfalls – especially if demand grows faster than expected." (Walmart St. No. 1, p. 20.) What is your response?

A. Mr. Lyon's reference to Monitoring Analytics and PJM analyses regarding tightening fundamentals and potential capacity shortfalls does not undermine the Company's MRPL proposal. While PJM market dynamics may fluctuate due to retirements or demand growth, these factors are addressed through PJM's capacity market mechanisms and regional planning processes, not through retail rate design. The Company's proposal does not attempt to influence generation adequacy or capacity market outcomes, which fall under PJM's jurisdiction. I would also note that the market fundamentals referenced by Mr. Lyon would likely result in higher compensation for customer-generators regardless of whether they were taking service under GSC-1 or GSC-2. Indeed, as I noted previously, no-load customer-generators' profits are tied to the PTC rate. Therefore, they have no financial incentive to support measures that could mitigate increases in the PTC. Rather, they have every financial incentive to make the PTC increase as much as possible.

Q. Please respond to Mr. Lyon's claim that "[c]hanging the classification of customer-generators under the GSC without robust transition protections would retroactively alter the economics of those investments" and "create stranded value for customers who acted reasonably under current rules." (Walmart St. No. 1, p. 21.)

A. The proposal does not retroactively alter the economics of existing investments; it establishes forward-looking rate classifications based on objective criteria such as Maximum Registered Peak Load. This approach ensures that customers are placed in the appropriate default service class consistent with cost-causation principles. The existence of prior investment decisions does not preclude necessary updates to rate design that promote equity and transparency for

all customers. Additionally, as I stated previously, the PTC is variable regardless of which rate class a customer-generator is in. It would be unreasonable for customer-generators to rely on a stable PTC to make investment decisions because there will always be changes to the Company's PTC.

III. VALUE OF EDI TRANSACTION INFORMATION FOR DEFAULT SUPPLY AND CAPACITY ALLOCATIONS

Q. What are your thoughts on RESA Witness Lacey's claim that PPL Electric benefits from the EDI transactions and without the information from them, the Company "could be saddled with excess default supply costs and capacity allocations from PJM" (RESA St. No. 1, pp. 30-31)?

A. PPL Electric does not rely on EDI transactions to determine its default service supply obligations or its PJM capacity allocations. These obligations are defined strictly by PJM's load and peak load contribution ("PLC") methodologies and are independent of supplier-initiated EDI activity. Even in the absence of EDI transactions, PPL Electric would continue to receive complete metering and settlement data that governs its capacity and default service requirements. RESA Witness Lacey's assertion incorrectly assumes that customer shopping information transmitted via EDI affects PJM cost assignments. No mechanism exists within PJM settlement rules that would cause PPL Electric to incur excess default supply or capacity costs due to lack of EDI transaction data.

IV. CONCLUSION

Q. Please summarize your rebuttal testimony.

A. PPL Electric's Maximum Registered Peak Load proposal ensures fair and transparent default service rate classification based on objective criteria, eliminating cost shifts caused by large customer-generators receiving retail-rate compensation for excess generation. It protects non-generating customers, addresses affordability concerns, and aligns with cost-causation principles without retroactively changing economics or disincentivizing renewable development. Alternative proposals like grandfathering and AEC transfers introduce unnecessary complexity and should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

PPL Electric Utilities Historical Price-to-Compare

Period	Residential PTC (c/kWh)	Change from Prior Period	Small C&I PTC (c/kWh)	Change from Prior Period
12/1/2025 -5/31/2026	12.953	3.71%	12.681	4.68%
6/1/2025 - 11/30/2025	12.490	15.96%	12.114	15.97%
12/1/2024 - 5/31/2025	10.771	7.28%	10.446	13.09%
6/1/2024 - 11/30/2024	10.040	-8.96%	9.237	-18.87%
12/1/2023 - 5/31/2024	11.028	-9.05%	11.386	-2.59%
6/1/2023 - 11/30/2023	12.126	-17.01%	11.689	-20.76%
12/1/2022 - 5/31/2023	14.612	18.16%	14.751	26.13%
6/1/2022 - 11/30/2022	12.366	38.31%	11.695	20.88%
1/1/2022 - 5/31/2022	8.941	-5.90%	9.675	-5.93%
12/1/2021 - 12/31/2021	9.502	25.95%	10.285	36.39%
6/1/2021 - 11/30/2021	7.544	3.10%	7.541	13.19%
12/1/2020 - 5/31/2021	7.317	0.45%	6.662	9.59%
6/1/2020 - 11/30/2020	7.284	-4.56%	6.079	-4.42%
12/1/2019 - 5/31/2020	7.632	0.62%	6.360	2.46%
6/1/2019 - 11/30/2019	7.585	7.76%	6.207	-14.32%
12/1/2018 - 5/31/2019	7.039	-5.50%	7.244	6.91%
6/1/2018 - 11/30/2018	7.449	-0.19%	6.776	-12.01%
12/1/2017 - 5/31/2018	7.463	-12.13%	7.701	2.82%
6/1/2017 - 11/30/2017	8.493	14.17%	7.490	4.07%
12/1/2016 - 5/31/2017	7.439	-0.69%	7.197	8.00%
6/1/2016 - 11/30/2016	7.491	-4.91%	6.664	-13.80%
12/1/2015 - 5/31/2016	7.878	-17.01%	7.731	-13.93%
6/1/2015-11/30/2015	9.493	-0.69%	8.982	-11.25%
3/1/2015-5/31/2015	9.559	2.59%	10.121	8.54%
12/1/2014-2/28/2015	9.318	4.04%	9.325	8.48%
10/1/2014-11/30/2014	8.956	1.61%	8.596	-2.15%
9/1/2014-9/30/2014	8.814	-2.46%	8.785	-8.35%
6/1/2014-8/31/2014	9.036	3.22%	9.585	-7.76%
3/1/2014-5/31/2014	8.754	0.00%	10.391	12.34%
12/1/2013-2/28/2014	8.754	-0.26%	9.250	21.63%
9/1/2013-11/30/2013	8.777	6.69%	7.605	-1.43%
6/1/2013-8/31/2013	8.227	13.68%	7.715	-28.66%
3/1/2013-5/31/2013	7.237	-4.20%	10.814	5.96%
12/1/2012-2/28/2013	7.554	-4.46%	10.206	-1.35%

PPL Electric Utilities Corporation
Estimated Price-to-Compare Sample Calculation
For Illustrative Purposes Only

Introduction:

The purpose of this document is to provide suppliers with an understanding of how the Price-to-Compare ("PTC") is calculated for all customer classes, pursuant to the Pennsylvania Public Utility Commission's ("PA PUC") Secretarial Letter issued on October 12, 2010. The data contained herein provides estimates of the PTC and reflects only a snap-shot in time.

The calculations of the PTC estimates are based on actual and estimated values. The Average Full Requirements and Average Block Prices are based on the results from the DSPP solicitations completed through July 2025. The E Factor Rate is based on the actual over/under-collection balances for April 2024 through March 2025. The Transmission Service Charge ("TSC") has been updated for the period of December 1, 2025 through November 30, 2026.

Disclaimer:

It should be noted that any and all data within this document are estimates, and actual charges will vary depending on customer demand, seasonal variations, or other factors. Forecast data is subject to change due to migration, customers leaving PPL Electric Utilities' service territory, or other events. In addition, all possible combinations of rates and surcharges have not been included in this document. Prices used in the PTC calculation are best-known values and will be updated pursuant to PPL Electric Utilities' tariff on file with the PA PUC. PPL Electric Utilities is not liable for any losses which may result from using the information contained in this document.

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Residential Class
Period: 12/1/2025 through 5/31/2026

1	Average Block Price	$	0.03443	(1)
2	Times portion of Residential Load		9.22%	
3	Total Weighted Block Price	$	0.00318	
4	Average Full Requirements Price	$	0.09433	(2)
5	Times portion of Residential Load		90.78%	(3)
6	Total Weighted Full Requirements Price	$	0.08563	
7	Subtotal (Line 3 + Line 6)	$	0.08880	
8	Multiplied by (1/(1-GRT)) *GRT = 5.9%*		1.062699	
9	Block and Full Requirements Price adjusted for GRT	$	0.09437	
10	E Factor Rate	$	(0.00188)	(4)
11	Administrative Charges Rate	$	0.00142	
12	Merchant Function Charge (MFC) Rate	$	0.00209	
13	Subtotal (Line 10 + Line 11 + Line 12)	$	0.00163	
14	Multiplied by (1/(1-GRT))		1.062699	
15	(E Factor + Admin Charges + MFC) x GRT	$	0.00173	
16	Generation Supply Charge (Line 9 + Line 15)	$	0.09610	
17	Transmission Service Charge (TSC)	$	0.03343	(5)
18	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 16 + Line 17) x 0.00001]	$	0.00000	(6)
19	PTC Estimate - Residential Class (Line 16 + Line 17 + Line 18)	$	0.12953	

Note: Data may not total due to rounding.

(1) The average Block price is adjusted for the Loss Factor and PJM deration factor.
(2) The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.
(3) After the Block load has been subtracted from total load, Full Requirements represents 100% of the load.
(4) Represents an over-collection of April 2024 through March 2025 actual revenue, which will be refunded over 12 months.
(5) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.
(6) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.

PPL Electric Utilities Corporation
Estimated Price-to-Compare Sample Calculation
For Illustrative Purposes Only
Residential Class

Line Item Explanations for the Residential Class:

Line 1 – An estimate of the average Block price for the applicable PTC period based on the solicitations completed.

Line 2 – Percentage represents the portion of total forecasted Residential load that is estimated to be supplied by the Block product for the applicable PTC period.

Line 3 – The weighted price of the Block product.

Line 4 – An estimate of the average Full Requirements price for the applicable PTC period based on the solicitations completed. Price includes all necessary energy, capacity, transmission other than Network Integration Transmission Service Charge ("NITS"), ancillary services, Pennsylvania Alternative Energy Portfolio Standard ("AEPS") requirement, transmission and distribution losses and congestion management costs, and such other services or products that are required to supply the specified percentage of a supplier's default load for a customer group set forth in a transaction confirmation pursuant to the Default Service Supply Master Agreement.

Line 5 - Percentage represents the portion of total forecasted Residential load that is estimated to be supplied by the Full Requirements product after deducting the Block product load, or 100% of the remaining Residential load.

Line 6 – The weighted price of the Full Requirements product.

Line 7 – The sum of the weighted prices for the Block, Full Requirements and Spot products.

Line 8 – Represents the gross-up effect of the statutory PA Gross Receipts Tax ("GRT") of 5.9%:

(1/1-5.9%) = 1.062699

Line 9 – An estimate of the Block and Full Requirements weighted price adjusted for the GRT.

Line 10 – The E factor rate represents the estimated over/under collection from the prior rate period that will be recovered during the current rate period.

Line 11 – The administrative charges rate for the Residential class.

Line 12 – Represents the Merchant Function Charge ("MFC") rate which is the provision for uncollectible accounts expense.

Line 13 – Sum of the estimate of the E factor, administrative charges and MFC.

Line 14 – Represents the gross-up effect of the statutory PA GRT of 5.9%:

(1/1-5.9%) = 1.062699

PPL Electric Utilities Corporation
Estimated Price-to-Compare Sample Calculation
For Illustrative Purposes Only
Residential Class

Line 15 – Sum of the estimate of the E factor, administrative charges and MFC adjusted for the GRT.

Line 16 – Represents the GSC by adding the Block and Full Requirements weighted price, including the E factor rate, administrative charges and the MFC. All components reflect the statutory PA GRT of 5.9%.

Line 17 – The Transmission Service Charge ("TSC") as filed with the PA PUC on October 31, 2025. This is the rate set forth in PPL Electric's tariff for December 1, 2025 through November 30, 2026 and reflects the statutory PA GRT of 5.9%.

Line 18 – The State Tax Adjustment Surcharge ("STAS") at 0.0001% multiplied by the subtotal of the GSC and TSC. All components reflect the statutory PA GRT of 5.9%.

Line 19 – The total PTC estimate for the Residential Class in $/kWh.

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Period: 12/1/2025 through 5/31/2026

1	Average Full Requirements Price	$	0.08414	(1)
2	Times portion of Small Commerical and Industrial Load		100.00%	
3	Total Weighted Full Requirements Price	$	0.08414	
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*		1.062699	
5	Block and Full Requirements Price adjusted for GRT	$	0.08942	
6	E Factor Rate	$	0.00038	(2)
7	Administrative Charges Rate	$	0.00353	
8	Merchant Function Charge (MFC) Rate	$	0.00020	
9	Subtotal (Line 6 + Line 7 + Line 8)	$	0.00411	
10	Multiplied by (1/(1-GRT))		1.062699	
11	(E Factor + Admin Charges + MFC) x GRT	$	0.00437	
12	Generation Supply Charge (Line 5 + Line 11)	$	0.09379	
13	Transmission Service Charge (TSC)	$	0.03302	(3), (5)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	$	0.00000	(4)
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	$	0.12681	

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.

(2) Represents an under-collection of April 2024 through March 2025 actual revenue, which will be collected over 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. LP4 transmission customers receive a demand charge of $21.647/kW.

PPL Electric Statement No. 15-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

SURREBUTTAL TESTIMONY OF
ANDREW CASTANARO
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION

Topics: **Maximum Registered Peak Load**

Dated: February 9, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew Castanaro. My business address is 827 Hausman Road, Allentown, Pennsylvania 18104.

Q. By whom are you employed and in what capacity?

A. I am employed by PPL Services Corporation ("PPL Services"), an affiliate of PPL Electric Utilities Corporation ("PPL Electric" or the "Company") that provides services to PPL Electric, as the Energy Procurement Manager.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted direct testimony (PPL Electric St. No. 15) and rebuttal testimony (PPL Electric St. No. 15-R) on behalf of the Company.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Office of Consumer Advocate ("OCA") Witness Zach Teti (OCA St. 6R), Customer-Generator Coalition ("CGC") Witness Guy Sharfman (CGC St. No. 1-R), Joint Solar Advocates ("JSA") Witnesses Kevin Lucas (JSA St. No. 1-R) and Walmart Inc. ("Walmart") Witness Matthew T. Lyon (Walmart St. No. 1-R), concerning the Company's Maximum Registered Peak Load ("MRPL") proposal, which would assign default service customers on the Generation Supply Charge ("GSC") to Rate GSC-1 and Rate GSC-2 based on their MRPL, as defined by the

Company's proposed retail tariff submitted in this proceeding.

Q. Have you prepared any exhibits or schedules in support of your surrebuttal testimony?

A. Yes. Attached to my surrebuttal testimony are PPL Electric Exhibits AC-1SR and AC-2SR.

II. MAXIMUM REGISTERED PEAK LOAD

Q. CGC Witness Sharman and Walmart Witness Lyon oppose JSA Witness Barnes's alternative proposal regarding the MRPL that would grandfather certain facilities and continue to advocate for their own grandfathering proposals. (CGC St. No. 1-R, pp. 8-12; Walmart St. No. 1-R, pp. 3, 9-10.) What is your response?

A. While I agree that JSA Witness Barnes's proposal should be rejected, I likewise maintain that CGC's and Walmart's grandfathering proposals should be denied for the reasons set forth in my rebuttal testimony. Nothing in CGC's or Walmart's rebuttal testimony alters my position that the MRPL should be approved and should apply to both existing and future interconnections to protect Small Commercial and Industrial ("C&I") from the adverse effects of these facilities on the Company's GSC-1 rate.

Q. Walmart Witness Lyon discounts OCA Witness Teti's concern about the "switching risk," claiming that "the fear that these projects will suddenly leave default service for the wholesale market" is "overstated." (Walmart St. No. 1-R, pp. 4-5.) Do you believe that is the "switching risk" that Mr. Teti is concerned about?

A. No. With respect to default service plans and procurement, "switching risk" pertains to customers switching from default service to Electric Generation Suppliers ("EGSs"). In that respect, Mr. Teti is concerned that the increases in the GSC-1 rate could cause non-customer-generators to switch to EGSs to insulate themselves from the rate increases caused by the compensation paid to no-load customer-generators. The "switching risk" is not, as alleged by Mr. Lyon, customer-generators "leav[ing] default service for the wholesale market."

The Company has several concerns about the dynamic between shopping and non-shopping Small C&I customers. First, as I stated in my direct and rebuttal testimony, the no load customer-generators are going to put upward pressure on the Small C&I Price to Compare ("PTC"). I am concerned that many EGSs set their offerings in relation to the Company's PTC, as evidenced by the offers on PA PowerSwitch.[1] A higher PTC will lead to higher EGS prices, leaving Small C&I customers nowhere to turn for affordable generation supply prices. Second, if there is a mass exodus of Small C&I customers from the GSC-1 rate, that will leave fewer and fewer customers to pay the net metering costs for no load customer-generators. This has the potential to accelerate the increase in Small C&I PTC prices.

Q. Mr. Lyon also alleges that PPL Electric's proposal "would likely negatively impact Pennsylvania's Climate Action Plan 2024 for deploying onsite solar to meet ~80 percent

[1] *See also* Dormady, Noah, et al., "Efficiency and Consumer Welfare Under Retail Electricity Deregulation: Analysis of Ohio's Retail Choice Markets," *Journal of Critical Infrastructure Policy*, vol. 6, no. 1, 2024, e12031, at 15, https://doi.org/10.1002/jci3.12031. ("We also find some evidence of price signaling, such that retail energy suppliers price not off of the wholesale market but rather price based upon the utility's default service.")

reduction by 2050 of Greenhouse Gase [sic] emissions." (Walmart St. No. 1-R, p. 5.) Please respond.

A. Foremost, I am advised by counsel that the strategies identified in the Climate Action Plan are not binding on any agency in Pennsylvania, including the Commission. Furthermore, Mr. Lyon fails to recognize the importance of the Climate Action Plan's use of the term "onsite solar." On page 80 of the Climate Action Plan, which Mr. Lyon cites in footnote 3 of his rebuttal testimony, it states that "[t]his strategy includes the installation of onsite distributed solar photovoltaics and storage in both the residential and commercial sectors, covering everything from single-family homes and shopping centers to schools and local government buildings."[2] Moreover, the Climate Action Plan goes on to emphasize that "most of the positive impacts" of such onsite solar "result from energy bill savings for households and business owners."[3] No-load customer-generator projects, which are advocated by opponents of the MRPL proposal, do not fit this description. They are not deploying solar onsite at existing buildings or homes to produce energy bill savings for themselves. Instead, they are interconnecting directly with the distribution system to profit off the net metering compensation structure in Pennsylvania. As explained in my direct and rebuttal testimony, the payouts to these customer-generators will drive up the PTC rate for Small C&I default service customers. Thus, from my perspective, PPL Electric's MRPL proposal does not

[2] *Pennsylvania Climate Action Plan Update 2024*, DEP'T OF ENVTL. PROT., p. 80 (Apr. 2025) (emphasis added), *available at* https://greenport.pa.gov/elibrary/GetDocument?docId=9584245&DocName=PENNSYLVANIA%20CLIMATE%20ACTION%20PLAN%202024.PDF%20%20%3Cspan%20style%3D%22color%3Agreen%3B%22%3E%3C%2Fspan%3E%20%3Cspan%20style%3D%22color%3Ablue%3B%22%3E(NEW)%3C%2Fspan%3E.

[3] *Id.* (emphasis added).

conflict with the Climate Action Plan, as it would help prevent business owners from paying an increased PTC rate to cover the costs of these payouts to no-load customer-generators.

Q. OCA Witness Teti asserts that JSA Witness Lucas's "concerns" that the Company allegedly "overstated the forecasted magnitude and value of excess generation" and "did not incorporate savings due to the reduction in load from net metering" are "valid." (OCA St. 6R, p. 5.) Do you agree?

A. No. As explained in my rebuttal testimony, the Commission should reject Mr. Lucas's criticisms about my analysis of the projected costs to be incurred by Rate GSC-1 non-customer-generators without the MRPL proposal in place. Nothing presented in Mr. Teti's rebuttal testimony alters or affects my position.

Q. Mr. Teti also agrees with JSA Witness Barnes's recommendations regarding negative Peak Load Contributions ("PLCs"). (OCA St. 6R, pp. 9-12.) Please respond.

A. I maintain that JSA Witness Barnes's recommendations regarding negative PLCs should be rejected. As explained in my rebuttal testimony, there are several flaws with Mr. Barnes's position, including his failure to recognize that negative PLCs would artificially reduce the Company's load obligation in a way that does not reflect actual system capacity needs and would shift risk and cost inequities onto other customers. Further, I noted that: (1) while PJM rules do not explicitly prohibit negative PLCs, the Company's approach of assigning zero load is consistent with PJM's established methodology and the principles underlying capacity obligations; and (2) if negative tags are established, the costs would increase for all non-

generating customers because the costs are still scaled to a single peak value. Moreover, Mr. Teti concedes that "the FERC-jurisdictional aspects of PJM's tariff and PPL's supplement to that tariff which address the negative PLC proposal may be beyond the scope of this proceeding." (OCA St. 6R, p. 11.) I agree, and for the reasons set forth in my rebuttal testimony, the Commission cannot and should not adopt Mr. Barnes's recommendations about negative PLCs in this proceeding.

Q. Do you observe any issues with Mr. Teti's OCA Exhibit ZT-1R, which he claims is a "numerical example" showing "the similarities and differences between the status quo and the MRPL proposal" (OCA St. 6R, p. 2)?

A. After reviewing Mr. Teti's OCA Exhibit ZT-1R, I believe he has made multiple errors when attempting to perform that calculation.

First, he is conflating a negative PLC with procurement load reduction, rather than with a reduction in capacity obligation. PLC is a determinant of the zonal capacity obligation and is assigned by PPL Electric to customers through their Installed Capacity ("ICAP") tags based on each customer's contribution during the Five Coincident Peaks ("5CP"). Mr. Teti errs by assuming that PPL Electric compensates for capacity. In fact, PPL Electric explained that it does not compensate for capacity in response to JSA V-4 in discovery. (*See* PPL Electric Exhibit AC-1SR [Answer to JSA V-4].)

Second, Mr. Teti fails to recognize that the Company already reflects an assumed level of net metering load reduction in its procurement forecast. Any variance between forecasted and actual load is addressed through the over-/under-collection mechanism and

refunded/recovered in a subsequent rate adjustment. To the extent actual load is lower than the load assumed for the procurement contracts, the Company would overcollect revenues, which would result in a reduction in a subsequent rate, with all else assumed equal.

Third, Mr. Teti mistakenly includes AEC costs as a separate component of the GSC-1 and GSC-2 procurement costs (see Lines F, G, P, and Q of OCA Exhibit ZT-1R). AECs are already included in the wholesale supplier obligations under the Company's Commission-approved DSP VI Plan. Therefore, Mr. Teti is double counting the costs associated with the AECs.

Due to these errors, Mr. Teti's calculations are flawed. Attached to my surrebuttal testimony as PPL Electric Exhibit AC-2SR is a presentation of OCA Exhibit ZT-1R with the calculations corrected to: (1) reflect the fact that PPL Electric does not compensate customer-generators for capacity; and (2) fix the net metering load reduction shown in his exhibit. Specifically, as you can see in PPL Electric Exhibit AC-2SR, I have zeroed out the 25,000 in hypothetical load reductions shown in Lines B and K of OCA Exhibit ZT-1R, have updated the "Customer-Generator Compensation" section of OCA Exhibit ZT-1R to reflect the correct components used to calculate customer-generators' compensation, and have zeroed out the AEC costs shown in Lines F and P of OCA Exhibit ZT-1R. It should also be noted that Mr. Teti's numerical example is limited in scope and reflects only the generation supply cost component in his GSC-1 and GSC-2 rate calculations. It does not represent the full PTC components. Excluded from the calculation are the E-factor, administrative charge, transmission service charge, the merchant function charge applicable to GSC-1 only, and the HP adder applicable to GSC-2 only. Because these components are omitted, Mr. Teti's

example does not reflect the full default service rate structure and should not be interpreted as a comparison of total default service prices.

Q. JSA Witness Lucas notes OCA Witness Teti's claims about an alleged lack of clarity surrounding the impact of PPL Electric's MRPL proposal. (JSA St. No. 1-R, pp. 2-3.) Do you believe PPL Electric addressed those concerns in its rebuttal testimony?

A. Yes. In fact, on pages 3 to 5 of my rebuttal testimony, I responded directly to Mr. Teti's requests for more clarity about the Company's proposal, including load reduction and PJM costs, retail rate components, and direct wholesale participation. Therefore, to the extent that Mr. Lucas relies on this alleged lack of clarity in support of his opposition to the MRPL proposal, it should be rejected.

Q. Do you agree with OCA Witness Teti that FERC Order 2222 provides an alternative construct for these generating facilities to receive compensation for their generation (OCA St. 6R, pp. 5, 10)?

A. Absolutely. As I noted in my rebuttal testimony, there is a variety of options for customer-generators to sell their generation. Participation as an aggregated DER resource in the wholesale market under FERC Order 2222 in the future is certainly an option that could be explored by customer-generators whose accounts would be reclassified from Rate GSC-1 to Rate GSC-2 under the MRPL proposal. I also agree with Mr. Teti that FERC Order 2222 would "ensur[e] wholesale market signals are at the right level and directly compensat[e] distributed energy resources for the provided service of capacity." (OCA St. 6R, p. 5.)

Q. Do you agree with JSA Witness Lucas that customer-generators do not need independent load to participate in net metering (JSA St. No. 1-R, p. 9)?

A. Yes, but whether a customer can participate in net metering is not at issue here. PPL Electric's MRPL proposal does not prohibit any customers from participating in net metering. The Company is simply updating the classification requirements for its default service rates to address the impact of certain customer-generators on its default service rates. Although some no-load customer-generators would be reclassified from Rate GSC-1 to Rate GSC-2, they would still be permitted to participate in net metering.

Q. JSA Witness Lucas also claims that "the AEPS Act contemplates that a *retail* value will be paid for power sold to the utility for resale – a *wholesale* transaction" and that "the point is not that excess electricity from customer-generators is purchased as the lowest cost supply." (JSA St. No. 1-R, p. 7.) Please respond.

A. I strongly disagree that the "the point is not that excess electricity from customer-generators is purchased as the lowest cost supply." That is exactly what PPL Electric is required to do under Chapter 28 of the Public Utility Code, and the need to comply with that obligation is the driving force behind PPL Electric's MRPL proposal.[4] Furthermore, it is indisputable that Rate GSC-2, which is paid by Large C&I default service customers, is a retail rate. Thus, there is no credible claim that PPL Electric's MRPL proposal somehow fails to compensate

[4] *See* 66 Pa. C.S.A. § 2807(e)(3.7)(ii) ("The default service provider's plan includes prudent steps necessary to obtain least cost generation supply…").

customer-generators for the full retail value of their excess generation.

III. CONCLUSION

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set V Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated December 3, 2025
Docket No. R-2025-3057164

JSA V-4	Identify, describe and explain why the rate paid per kWh for excess generation to net-metered customer generators does not include a capacity component if such component is included in the GSC-2 charge components. Provide all Documents used, relied upon and/or that support your answer.
PPL Electric Response	The capacity charge in the capacity calculation uses the customer's ICAP value. The calculation was developed based on the logic that net-metered customer generators are producing energy and that the ICAP value would be zero. Therefore, the zero ICAP value multiplied by the rate is zero, and the kWh component is the value that remains.

Maximum Registered Peak Load (MRPL) - Numerical Example

			[1] Status Quo		[2] MRPL Proposal		[3] = [2] - [1] Difference	
	GSC-1 SCI*							
[A]	Gross Load (w/ Losses)	*MWh*	500,000		500,000		0	
[B]	Net Metering (DSP Adjustment)	*MWh*	0		0		0	
[C] = [A] + [B]	**GSC-1 SCI Procured Amount**	*MWh*	**500,000**		**500,000**		**0**	
[D]	Weighted Price	*$/MWh*	**$ 73.50**		**$ 72.50**	$	(1.00)	See 'Risk Premium - Example' Tab
[E] = [C] x [D]	GSC-1 SCI Procurement Cost	*$*	$ 37,750,000	#	$ 37,250,000	$	(500,000)	
[F]	AEC	*$*	$ -		$ -	$	-	AECs included in wholesale supplier obligations per the approved DSP VI plan
[G] = [E] + [F]	**Procurement + AEC Cost**	*$*	**$ 37,750,000**		**$ 37,250,000**	**$**	**(500,000)**	
[H]	Customer Load (w/out Losses)	*MWh*	425,000		425,000		-	
[I] = [G] / ([H] x 1000)	**Rate**	*$/kWh*	**$ 0.08882**		**$ 0.08765**	**$**	**(0.00117)**	
	GSC-2*							
[J]	Gross Load (w/ Losses)	*MWh*	250,000		250,000		0	
[K]	Net Metering	*MWh*	0		0		0	
[L] = [J] + [K]	**GSC-2 Procured Amount**	*MWh*	**250,000**		**250,000**		**0**	
[M]	Capacity Price	*$/MWh*	$ 30.00		$ 30.00	$	-	
[N]	Energy Price	*$/MWh*	$ 40.00		$ 40.00	$	-	
[O] = L x ([M] + [N])	GSC-2 Procurement Cost	*$*	$ 18,000,000		$ 18,000,000	$	-	
[P]	AEC	*$*	$ -		$ -	$	-	AECs included in wholesale supplier obligations per the approved DSP VI plan
[Q] = [O] + [P]	**Procurement + AEC Cost**	*$*	**$ 18,000,000**		**$ 18,000,000**	**$**	**-**	
[R]	Customer Load (w/out Losses)	*MWh*	215,000		215,000		-	
[S] = [Q] / ([R] x 1000)	**Rate**	*$/kWh*	**$ 0.08372**		**$ 0.08372**	**$**	**-**	
	Customer-Generator Compensation							
[T] = [B] + [K]	Net Metering	*MWh*	85,000		85,000		0	
[U] = [D] or [N]	Compensation Rate - Supply	*$*	$ 0.0888		$ 0.0400	$	(0.05)	
[V]	Other Components**	*$*	$ 0.0355		$ 0.0317	$	(0)	
[W] = [T] x ([U] + [V])	Total Compensation	*$*	$ 10,563		$ 6,096	$	(4,467)	
	Total							
[X] = [G] + [V]	Effective GSC-1 Cost	*$*	$ 37,760,563		$ 37,256,096	$	(504,467)	
[Y] = [X] / ([H] x 1000)	*Effective GSC-1 Rate*	*$/kWh*	*$ 0.08885*		*$ 0.08766*	*$*	*(0.00119)*	
[Z] = [Q] + [W]	Effective GSC-2 Cost	*$*	$ 18,010,563		$ 18,006,096	$	(4,467)	
[AA] = [Z] / ([R] x 1000)	*Effective GSC-2 Rate*	*$/kWh*	*$ 0.08377*		*$ 0.08375*	*$*	*(0.00002)*	
[AB] = [Y] + [AA]	**Effective GSC-1 + GSC-2 Cost**	*$*	**$ 55,771,126**		**$ 55,262,192**	**$**	**(508,934)**	

* Negative peak load is a reduction to zonal capacity supply obligations that get allocated to customers and does not reduce procurement forecasted load, which has already been accounted for; variances from default load reductions resulting from excess NEM generation are captured in the over/under collection and impact the E-factor rate in the subsequent rate

** Other components include E-factor, administrative charges, MFC and transmission for GSC-1 from direct testimony exhibits tab Dec. '25 SCI PTC and HP adder, E-factor, admin and transmission for GSC-2 from discovery response to JSA II-10 Attachment 1

	Maximum Registered Peak Load (MRPL) - Numerical Example						
[A]	Gross Load (w/ Losses)	*MWh*	500,000				
[B]	Customer Load (w/out Losses)	*MWh*	425,000				
[C]	Current BTM Generation Nameplate Capacity	*MW*	15				
[D]	Pipeline BTM Generation Nameplate Capacity	*MW*	8				
[E]	DSP Supplier Cost	*$/MWh*	**$ 72.50**	*assumed marginal cost is flat (not increasing)*			
			[1]	**[2]**	**[3]**	**[4]**	**[5]**
			Scenario 1 PPL	**Scenario 2 Low Shortage Risk**	**Scenario 3 Med Shortage Risk**	**Scenario 4 High Shortage Risk**	**Average**
[F]	Scenario Likelihood	%	10%	30%	40%	20%	100%
[G]	Completion Rate	%	50%	30%	30%	15%	29%
[H]	Capacity Factor	%	30%	30%	20%	20%	24%
[I] = [A]	Gross Load (w/ Losses)	*MWh*	500,000	500,000	500,000	500,000	500,000
[J] = (([C] x [H]) + ([D] x [G]x[H])) x 4380	Net Metering	*MWh*	24,966	22,864	15,242	14,191	18,291
[K] = [I] - [J]	Net Energy Demand	*MWh*	**475,034**	477,136	484,758	485,809	481,709
[L] = [K-1]	**GSC-1 SCI Procured Amount**	*MWh*	**475,034**	**475,034**	**475,034**	**475,034**	**475,034**
[M] = [K] - [L]	Shortage	*MWh*	-	2,102	9,724	10,775	6,675
[N] = [E-1] x [L]	DSP Supplier Cost - GSC-1 SCI Procured Amount	*$*	$ 34,439,965	$ 34,439,965	$ 34,439,965	$ 34,439,965	$ 34,439,965
[O] = [E-1] x [M]	DSP Supplier Cost - Shortage Cost	*$*	$ -	$ 152,424	$ 704,961	$ 781,173	$ 483,946
[P] = [N] + [O]	**Total Cost**	*$*	**$ 34,439,965**	**$ 34,592,389**	**$ 35,144,926**	**$ 35,221,138**	**$ 34,923,911**
[Q] = [P] / [L]	**DSP Supplier Bid - Rate Requirement**	*$/MWh*	**$ 72.50**	**$ 72.82**	**$ 73.98**	**$ 74.14**	**$ 73.52**
[R] = [L] x [Q]	GSC-1 SCI Procurement Cost	*$*					**$ 34,923,911**
[S]	*Check*	*$*					*$ 37,750,000*

$ 1.02 *Risk Premium*

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

REJOINDER TESTIMONY OF ANDREW CASTANARO ON BEHALF OF PPL ELECTRIC UTILITIES CORPORATION

Topics: **Maximum Registered Peak Load**

Dated: February 13, 2026

31973192v1

Business Use

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew Castanaro. My business address is 827 Hausman Road, Allentown, Pennsylvania 18104.

Q. By whom are you employed and in what capacity?

A. I am employed by PPL Services Corporation ("PPL Services"), an affiliate of PPL Electric Utilities Corporation ("PPL Electric" or the "Company") that provides services to PPL Electric, as the Energy Procurement Manager.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted direct testimony on behalf of the Company, PPL Electric Statement No. 15, rebuttal testimony, PPL Electric Statement No. 15-R, and surrebuttal testimony, PPL Electric Statement No. 15-SR.

Q. What is the purpose of your rejoinder testimony?

A. The purpose of my rejoinder testimony is to respond to the surrebuttal testimony of Joint Solar Advocates Witnesses Lucas (JSA St. No. 1-SR) and Barnes (JSA St. No. 2-SR), Customer-Generator Coalition Witness Sharfman (CGC St. No. 1-SR), and Walmart Inc. ("Walmart") Witness Lyon (Walmart St. No. 1-SR) concerning the Company's Maximum Registered Peak Load ("MRPL") proposal. Moreover, in the course of reviewing their surrebuttal testimony,

I discovered certain corrections that I needed to make to my original analyses that were presented as part of my direct testimony as PPL Electric Exhibits AC-1 through AC-3. Based on those corrections and the other parties' surrebuttal testimony, I also have developed updated analyses that are discussed and presented as part of this rejoinder testimony.

Q. Have you prepared any exhibits in support of your rejoinder testimony?

A. Yes. As explained in my rejoinder testimony, I have prepared corrected versions of PPL Electric Exhibits AC-1 through AC-3. They are attached to my rejoinder testimony as PPL Electric Exhibits AC-1RJ through AC-3RJ, respectively. Additionally, in response to concerns raised by other parties about the Company's analyses, I have prepared updated analyses for these three scenarios using a 17.3% capacity factor and reflecting the impact of excess generation on the Company's default service supply requirements. Those analyses are shown in PPL Electric Exhibits AC-4RJ through AC-6RJ.

II. MAXIMUM REGISTERED PEAK LOAD

Q. Before addressing other parties' surrebuttal testimony more directly, could you please describe the corrections that you have made to PPL Electric Exhibits AC-1 through AC-3, which are reflected in PPL Electric Exhibits AC-1RJ through AC-3RJ?

A. Yes. In the process of reviewing other parties' surrebuttal testimony and preparing for the hearings, I discovered that there were two corrections that needed to be made. First, in PPL Electric Exhibit AC-1, the calculations were supposed to be based on a 36% cancellation rate,

which is the experienced cancellation rate for these projects. However, the analysis incorrectly used a 0% cancellation rate instead, which resulted in the excess generation, Price to Compare ("PTC"), and net metering compensation figures being overstated. This issue was also pointed out in JSA Witness Lucas's surrebuttal testimony (JSA St. No. 1-SR, p. 6.) Therefore, I have made this correction in PPL Electric Exhibit AC-1RJ. Further, because I relied on the PTC rate from PPL Electric Exhibit AC-1 in calculating the average bill increase for Small C&I customers in my rebuttal, I would like to clarify that the $174.01 average monthly bill impact figure on page 11 of my rebuttal testimony should be $97.42 instead.

Second, due to an error, PPL Electric Exhibits AC-1 through AC-3 significantly undercounted the amount of excess generation from the no-load customer-generator projects that are in the Company's interconnection queue. Specifically, the Company only included generation from distribution Rate Schedule GS-3 and default service Rate GSC-1 but not the projects with peak load less than 100 kW that would fall under distribution Rate Schedule LP-4 and default service Rate GSC-1. Thus, the analyses mistakenly failed to capture the excess generation attributable to Rate LP-4 no-load customer-generators' projects that would fall under Rate GSC-1. This resulted in a large understatement of the excess generation and, by extension, the impact on the Price to Compare ("PTC") and net metering compensation paid to no-load customer-generators.

For example, when incorporating the Rate LP-4/Rate GSC-1 excess generation in the 36% cancellation rate scenario, the total kWh of excess generation increases from 1,430,455,085 kWh to 2,615,689,298 kWh in 2029, the PTC increases from $0.20474 per

kWh to $0.29980 per kWh in 2029, and total net metering compensation paid to the no-load customer-generators increases from approximately $303,708,557 million to $795,012,047 million in 2029 (see PPL Electric Exhibits AC-1 and AC-1RJ).

Q. Given those significant increases reflected in PPL Electric Exhibits AC-1RJ through AC-3RJ, along with concerns parties have raised concerning the Company's analyses in their surrebuttal testimony, have you prepared any updated analyses in response?

A. Yes. I have prepared updates analyses of these three cancellation rate scenarios. Although I maintain that the Company's original methodology was sound, I recognize that the corrected data shows significant increases in the impact of these no-load customer-generators on total excess generation, the PTC, and net metering compensation. Additionally, I thought it would be beneficial to incorporate a couple adjustments to the analyses. First, instead of the 29.8% capacity factor used in PPL Electric Exhibits AC-1 through AC-3 and AC-1RJ through AC-3RJ, the updated analyses utilize a 17.3% capacity factor. That equals the fixed tilt capacity factor suggested by JSA Witness Lucas. (*See* JSA St. No. 1, p. 41.) Second, other parties have criticized my analyses for not reflecting how the excess generation reduces the Company's default service supply requirements. Both of these adjustments place downward pressure on the PTC projections in my analyses over time, as shown when comparing the corrected analyses in PPL Electric Exhibits AC-1RJ through AC-3RJ to the updated analyses in PPL Electric Exhibits AC-4RJ through AC-6RJ.

Q. Do you have any observations about the results of the corrected analyses?

A. Yes. As you can see, these analyses reinforce the need to approve PPL Electric's MRPL proposal. With the corrected excess generation data, my original methodology shows the total net metering expense for no-load customer-generators under Rate GSC-1 increasing from approximately $10,841,474 in 2025 to $795,012,047 in 2029 under the 36% cancellation rate, $523,406,225 in 2029 under the 50% cancellation rate, and $192,256,897 in 2029 under the 75% cancellation rate. (*See* PPL Electric Exhibits AC-1RJ through AC-3RJ.) Under each of those three cancellation rate scenarios, the PTC in effect is calculated as rising significantly to the following rates at May 31, 2030: (1) $0.29980 per kWh under the 36% cancellation rate; (2) $0.25083 per kWh under the 50% cancellation rate; and (3) $0.17755 per kWh under the 75% cancellation rate.

I recognize that these PTC rate increases are substantial, and if they came to fruition, would likely cause catastrophic impacts in the retail electric market for Small C&I customers. Non-customer-generators under Rate GSC-1 would be paying exorbitant rates and likely forced to seek an alternative supplier. Such an outcome would create a significant switching risk from a default service supply procurement standpoint and lead to fewer customers on Rate GSC-1 being able to absorb these costs in the PTC rate, in turn leading to the rate increasing even further. Compounding the harm, I expect that EGSs would increase their rate offerings to customers based on the increased level of the PTC, leaving non-customer-generators in the Small C&I class likely without an option to avoid these cost increases.

For these reasons, and in response to other parties' criticisms, I believe it would be helpful to present how the PTC rate and net metering compensation would be affected when incorporating other assumptions that have been raised by other parties. Those assumptions, while tempering the PTC rate and net metering compensation somewhat, still show that PPL Electric's MRPL proposal should be approved.

Q. Could you please provide more detail about the results of the updated analyses?

A. As seen in PPL Electric Exhibits AC-4RJ through AC-6RJ, the lower capacity factor of 17.3% and the offsetting of default service supply procurements due to the excess generation place downward pressure on the net metering compensation and the PTC compared to the corrected analyses. However, there is a clear "bell curve" effect. Under the 36% cancellation rate scenario, the PTC peaks at $0.30562 per kWh in 2029 in the analysis. However, the rate then drops significantly to $0.03158 per kWh in 2030. This is due to the amount of excess generation from these no-load customer-generator projects surpassing the entire default service supply requirements for the Rate GSC-1 class of 895,765 MWh. That could be viewed as welcome news to non-customer-generators, but the path to get there is through paying significantly higher rates for years in the interim. In fact, PPL Electric would be paying an annual premium of approximately $414,198,666 by 2029 for the supply from the no-load customer-generators, compared to the cost of the supply that PPL Electric could obtain through its full requirements contracts. That equates to a PTC rate premium of $0.22032 per

kWh (i.e., the PTC rate of $0.30562 per kWh minus the procurement rate under the full requirements contracts).

Due to the risk that customers would switch to get off the increased PTC rates during that period, it is unclear when the lower rates would come to pass, if ever. Moreover, the lower rates would reduce the compensation paid to the no-load customer-generators significantly. As opponents of the MRPL proposal have argued that any reduction in the no-load customer-generators' compensation from the current rate construct would render projects unprofitable, I have to expect a PTC rate of $0.03158 per kWh would be a negative outcome for them financially.

The 50% and 75% cancellation rate scenarios are not much better. The increases in the PTC rate and total net metering compensation are more gradual: a PTC of $0.23423 per kWh in 2029 and $354,868,530 in total net metering compensation in 2029 under the 50% cancellation rate scenario, and a PTC of $0.16178 per kWh in 2029 and $118,804,292 in total net metering compensation in 2029 under the 75% cancellation rate scenario. However, over time, the story remains the same. The more no-load customer-generators added to the system, the more the Small C&I PTC rate will increase over time. Eventually, once the excess generation from the no-load customer-generators eclipses the Rate GSC-1 default service supply requirements, the bottom would fall out, and the PTC rate would drop. As I explain above, however, such an outcome may not come to pass and would force non-customer-customers to bear significant cost increases for years.

Q. Could you please explain why under the 50% cancellation rate scenario, the PTC rate as of May 31, 2030, is $1.32804 per kWh?

A. As the net metering compensation costs increase, those costs are recovered through the reconciliation of the Rate GSC-1 which is reflected in the "E-Factor" value in the PTC calculation. Under this scenario, the excess generation in 2028 would exceed the Small C&I default service supply requirements by approximately 551,600 MWh. PPL Electric is required to compensate customer-generators for the value of that excess generation, even if it exceeds the Company's supply requirements. The compensation costs associated with that excess generation of approximately 551,600 MWh would then be reflected in and recovered through the next reconciliation of the Rate GSC-1, leading to a substantial increase in the subsequent PTC rate. Ultimately, that rate provides further evidence of the significant volatility and risk that these no-load customer-generators are injecting into the PTC rate paid by Small C&I customers.

Q. In his surrebuttal testimony, JSA Witness Lucas criticizes your all-else-equal approach in PPL Electric Exhibits AC-1 through AC-3 because it does not reflect the corresponding decrease in procurement and subsequent procurement costs. (JSA St. No. 1-SR, pp. 5-6.) Could you please respond?

A. Yes. I believe Mr. Lucas's criticism has been appropriately addressed through my updated analyses in PPL Electric Exhibits AC-4RJ through AC-6RJ. As shown in those analyses and as explained above, the decrease in procurement requirements places downward pressure on

the PTC rate, but not enough to cover the costs of paying the net metering compensation to the no-load customer-generators and keep the PTC rate from rising significantly. Also, the excess generation from no-load customer-generators that is currently in the interconnection queue would, assuming the Company's actual cancellation rate of 36%, equal the entire default service supply requirements for Rate GSC-1 by 2029. As I noted previously, that would create serious issues for the no-load customer-generators and the retail electric market.

Q. Mr. Lucas also points out that PPL Electric Exhibit AC-1 used an incorrect cancellation rate of 0% instead of 36% and questions if the cancellation rates of 50% and 75% used in PPL Electric Exhibits AC-2 and AC-3, respectively, were correct. (JSA St. No. 1-SR, pp. 6-10.) Please respond.

A. As stated previously, attached as PPL Electric Exhibit AC-1RJ is a corrected version of PPL Electric Exhibit AC-1. In PPL Electric Exhibit AC-1RJ, I have included the correction of the 36% cancellation rate. Also, I have reviewed and confirmed that the cancellation rates used in PPL Electric Exhibit AC-2 and AC-3 contained no errors. However, I made corrections to the excess generation data used in PPL Electric Exhibits AC-1 through AC-3 as well, which are reflected in PPL Electric Exhibits AC-1RJ through AC-3RJ.

Q. Mr. Lucas also argues that PPL Electric has used "unrealistic assumptions" when calculating the amount of excess generation that would be produced by the no-load customer-generators. (JSA St. No. 1-SR, pp. 10-12.) Would you please respond?

A. As I have explained above, my original analyses actually undercounted the amount of total excess generation from the no-load customer-generator projects in the interconnection queue, due to the distribution Rate LP-4 projects not being included. When making that correction, it resulted in a significant increase in the projected excess generation. However, in response to Mr. Lucas's concerns about the generation projected on a per-project basis that were set forth in his surrebuttal testimony, my updated analyses use the 17.3% fixed tilt capacity factor that he suggested in his direct testimony instead of the 29.8% capacity factor used in my original and corrected analyses. While I maintain that the 29.8% capacity factor is reasonable and appropriate, I believe the use of the 17.3% capacity factor in the updated analyses should resolve Mr. Lucas's concern about that assumption.

Q. In attempted support of his reference to the practices of the Illinois Power Agency ("IPA") and Commonwealth Edison ("ComEd") in Illinois, JSA Witness Barnes asserts that the differences you identified in the default service structure in Pennsylvania are a "distinction without a difference" because in "both Illinois and Pennsylvania," it is the "customers and suppliers, rather than the procuring entity," that "bear[s] the market risk." (JSA St. No. 2-SR, p. 10.) Please respond.

A. Mr. Barnes misses my point. In my rebuttal, I explained that IPA, as the centralized state procurement entity, absorbs the risk associated with any volatility or distortions in Peak Load Contribution ("PLC") assignments, including negative PLC values. This is important because Mr. Barnes continues to push for PPL Electric to incorporate negative PLCs into its FERC

Open Access Transmission Tariff ("OATT"). (*See* JSA St. No. 2-SR, pp. 11-13.) Therefore, Mr. Barnes would force PPL Electric, not some state entity that handles procurement for all electric utilities, to directly bear the risk associated with any volatility or distortions in the PLC assignments, including negative PLC values.

Q. Mr. Barnes maintains his recommendation that the Rate GSC-2 rate should be modified to provide a capacity credit if the customer registers a negative PLC. (JSA St. No. 2-SR, pp. 13-15.) Relatedly, CGC Witness Sharfman contends that "if customer-generators are moved to GSC-2, the record raises questions as to whether excess generation credits under GSC-2 reflect the same retail price components charged to those customers, including capacity." (CGC St. No. 1-SR, p. 15.) Would you please respond?

A. I continue to disagree that there are issues with PPL Electric's current net metering compensation structure under Rate GSC-2 and with Mr. Barnes's reasoning for his proposal. However, as a means of trying to address these witnesses' concerns, PPL Electric would be willing to incorporate a capacity component to the net metering compensation calculation for Rate GSC-2 customer-generators as part of its compliance retail tariff filing in this case.

Q. CGC Witness Sharfman also asserts that "PPL's asserted justification for MPRL in this proceeding should be evaluated based on the quantitative and operational evidence in the record, rather than assumed." (CGC St. No. 1-SR, p. 3.) Please respond.

A. I agree that the MRPL proposal should be evaluated based on quantitative and operational evidence. PPL Electric has put forward that evidence in this proceeding, most recently with the corrected and updated analyses attached as PPL Electric Exhibits AC-1RJ through AC-6RJ. Mr. Sharfman's claim that there is no "record evidence establishing causal link between GSC-1 customer-generators and harm to non-customer-generators" has no merit and should be rejected. (CGC St. No. 1-SR, p. 3.)

Q. Walmart Witness Lyon argues that your statement that the MRPL would only affect 18 existing customer-generators "ignores the 'chilling effect' that the proposal has on the pipeline of future projects." (Walmart St. No. 1-SR, pp. 7-8.) Please respond.

A. As evidenced by my corrected and updated analyses, PPL Electric needs to implement the MRPL now to get ahead of the problems that will be caused by the large influx of no-load customer-generators. These no-load customer-generators also appear to be unaware that the amount of excess generation they will put onto the distribution system will eventually equal and then exceed the entire default service supply requirements of the Small C&I class, which would have a dramatic effect on the PTC rate, for the reasons I explained previously.

Further, there is an ever-growing number of electric utilities in Pennsylvania who have adopted or proposed to adopt methodologies like the MRPL, specifically, UGI Utilities, Inc. – Electric Division, Citizens' Electric Company, PPL Electric, and, most recently, FirstEnergy Pennsylvania Electric Company, which recently made an MRPL proposal as part of its Default Service Plan ("DSP") VII proceeding at Docket No. P-2026-3060298. Additionally,

there remains the prospect that legislation is passed that prohibits generating facilities with no independent load from participating in net metering.

For all these reasons, the developers' continued efforts to pursue these projects is a risky proposition, and while they may have "acted in good faith by investing in the future of distributed generation and clean energy goals of Pennsylvania," there are, at the very least, unintended consequences to these projects that will adversely affect non-customer-generators unless PPL Electric's MRPL proposal and other utilities' proposals like it are implemented.

Q. Mr. Lyon asserts that "Walmart pays the PTC on its substantial retail load and has a vested interest in affordable and reasonable rates for all customers" and that its "status as a 'no-load' generator under specific accounts at specific sites results from oversizing production relative to load in order to maximize clean energy production." (Walmart St. No. 1-SR, p. 5.) Please respond.

A. If Walmart's goal were to increase "onsite generation and reduce[] emissions," nothing is preventing Walmart from installing alternative energy sources at the sites of its load (e.g., retail stores, distribution centers). However, it appears Walmart is pursuing these no-load customer-generator projects to maximize the amount of compensation that it can receive. In that respect, every default service Small C&I competitor of Walmart in PPL Electric's service territory would be forced to cover the costs of that compensation paid to Walmart.

III. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

2024

Cashout goes out 5/31/24
Reconciled 3/31/24
Half of reconciliation hits 6/1/24
Other half hits 12/1/24

Excess generation 6/1/23 - 5/31/24
Net metering expenses April 2023 - March 2024

2025

Cashout goes out 5/31/25
Reconciled 3/31/25
Half of reconciliation hits 6/1/25
Other half hits 12/1/25

Excess generation 6/1/24 - 5/31/25
Net metering expenses April 2024 - March 2025

2026

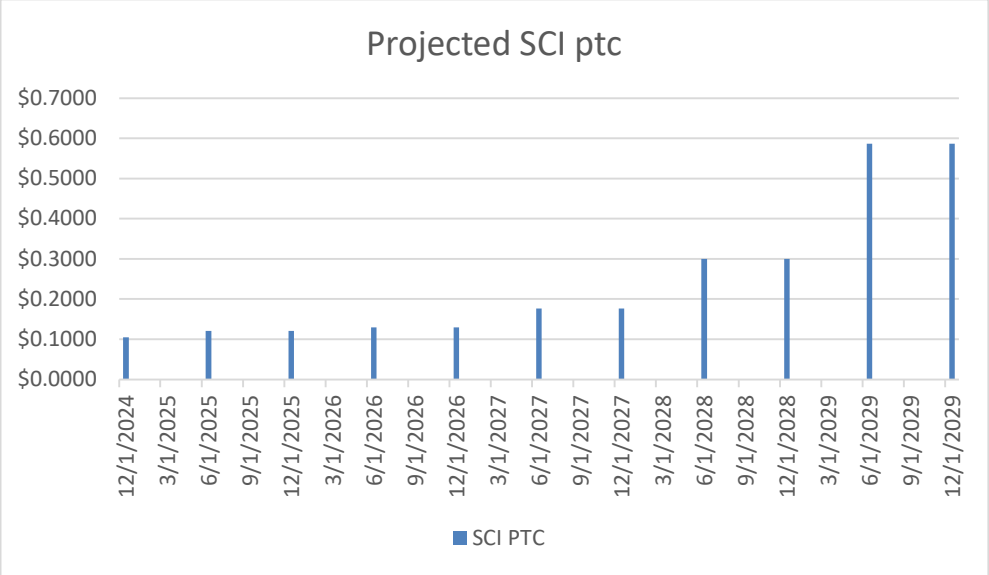
Cashout goes out 5/31/26
Reconciled 3/31/26
Half of reconciliation hits 6/1/26
Other half hits 12/1/26

Excess generation 6/1/25 - 5/31/26
Net metering expenses April 2025 - March 2026

PROJECTED:	12/1/2024	6/1/2025	12/1/2025	6/1/2026
SCI PTC	$ 0.10446	0.12114	$ 0.12114	$ 0.12933

PROJECTED:	2024	2025	20
SCI Net Metering Expense[(1)]	$ 10,350,518	$ 10,841,474	$

[(1)] Net Metering expense reflected in each SCI PTC is 1/2 of the amount filed in the March GSC-1 reconcil (ex. in June '24, the PTC included 1/2 the reconciliation amount for the GSC-1 reconciliation filed in Marc April '23-March '24)



12/1/2026	6/1/2027	12/1/2027	6/1/2028	12/1/2028	6/1/2029
$ 0.12933	$ 0.17642	$ 0.17642	$ 0.29980	$ 0.29980	$ 0.58659

26	2027	2028	20
13,335,172	$ 92,693,656	$ 300,694,795	$

iation, includes expenses from April - March of year
:h '24, which included net metering expenses from

45.64%
796%

12/1/2029
$ 0.58659

29
784,170,573

	Total
Projected 2025 kWh Bank	49,842,515
Projected 2025 kWh Bank w/ Cancellation Rate ~36%	31,899,209
Projected 2026 kWh Bank	172,008,146
Projected 2026 kWh Bank w/ Cancellation Rate ~36%	110,085,214
Projected 2027 kWh Bank	1,119,886,777
Projected 2027 kWh Bank w/ Cancellation Rate ~36%	716,727,537
Projected 2028 kWh Bank	2,663,225,657
Projected 2028 kWh Bank w/ Cancellation Rate ~36%	1,704,464,420
Projected 2029 kWh Bank	4,087,014,528
Projected 2029 kWh Bank w/ Cancellation Rate ~36%	2,615,689,298

Cancellation Rate	36%
Percentage of SCI Load in Queue	35%

(1) SCI accounts for roughly 38% of new service applications for solar (GS3) and the other are LP4
team; but these are smaller applications than LP-4, so adjusting to 35% of total kWh (estimate) p
Planning)

SCI Only(1)
49,842,515
31,899,209
172,008,146
110,085,214
1,119,886,777
716,727,537
2,663,225,657
1,704,464,420
4,087,014,528
2,615,689,298

cancellation rate now incorporated into kWH projection

according to the Interconnections
er Micah Clarke (Distribution

Year of Reconciliation/Cashout:	2024	2025	2026
SCI Excess kWh for MGs (kWh Cashed Out)			110,085,214
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114
SCI Net Metering Expense from MGs			$ 13,335,172
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 24,176,646
	^ Actual expense	*^ Actual expense*	

NOTES:
The amount of the net metering expense that is included in the reconciliation is only through March of a given Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

2027	2028	2029	PTC at 12/1/30	
716,727,537	1,704,464,420	2,615,689,298		<-- Updated 2/10/26
$ 0.12933	$ 0.17642	$ 0.29980	$ 0.58659	
$ 92,693,656	$ 300,694,795	$ 784,170,573		
$ 103,535,130	$ 311,536,269	$ 795,012,047		<--cashout amount to be reflected

year and the cashout kWh is through May of that same year, so there is some estimation happening here wi

in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each colur

th timing

mn year

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/29 & 12/1/29

1	Average Full Requirements Price	
2	Times portion of Small Commerical and Industrial Load	
3	Total Weighted Full Requirements Price	
4	Multiplied by (1/(1-GRT))	*GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT	
6	E Factor Rate	
7	Administrative Charges Rate	
8	Merchant Function Charge (MFC) Rate	
9	Subtotal (Line 6 + Line 7 + Line 8)	
10	Multiplied by (1/(1-GRT))	
11	(E Factor + Admin Charges + MFC) x GRT	
12	Generation Supply Charge (Line 5 + Line 11)	
13	Transmission Service Charge (TSC)	
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.43832	(2)
$	0.00311	
$	0.00019	
$	0.44162	
	1.062699	
$	0.469309	
$	0.55501	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.58659	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2028 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	797,112,655
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	1,593,360,089
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(749,714,619)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (746,808,912)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (754,009,855)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2029

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	151,681,672	
654,715,616	136,851,235	
3,449,574	(22,283)	
2,100,608	795,012,047	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	932,066,445	
30,670,154	(780,384,773)	
2,472,504	433,203	
$ 33,142,658	$ (779,951,570)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (785,258,234)	
$ 15,624,190	$ (392,629,117)	
$ 15,624,190	$ (392,629,117)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/28 & 12/1/28

1	Average Full Requirements Price	
2	Times portion of Small Commerical and Industrial Load	
3	Total Weighted Full Requirements Price	
4	Multiplied by (1/(1-GRT))	*GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT	
6	E Factor Rate	
7	Administrative Charges Rate	
8	Merchant Function Charge (MFC) Rate	
9	Subtotal (Line 6 + Line 7 + Line 8)	
10	Multiplied by (1/(1-GRT))	
11	(E Factor + Admin Charges + MFC) x GRT	
12	Generation Supply Charge (Line 5 + Line 11)	
13	Transmission Service Charge (TSC)	
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.16845	(2)
$	0.00311	
$	0.00019	
$	0.17175	
	1.062699	
$	0.182519	
$	0.26821	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.29980	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2027 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	313,636,877
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	1,109,884,311
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(266,238,841)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (263,333,134)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (270,534,077)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2028

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	151,681,672	
654,715,616	136,851,235	
3,449,574	(22,283)	
2,100,608	311,536,269	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	448,590,667	
30,670,154	(296,908,995)	
2,472,504	433,203	
$ 33,142,658	$ (296,475,792)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (301,782,456)	
$ 15,624,190	$ (150,891,228)	
$ 15,624,190	$ (150,891,228)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/27 & 12/1/27

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.05235	(2)
$	0.00311	
$	0.00019	
$	0.05565	
	1.062699	
$	0.059139	
$	0.14484	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.17642	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2026 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	105,635,738
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	901,883,172
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(58,237,702)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (55,331,995)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (62,532,938)

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2027

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	151,681,672
654,715,616	136,851,235
3,449,574	(22,283)
2,100,608	103,535,130
1,027,846	225,446
661,293,644	240,589,528
30,670,154	(88,907,856)
2,472,504	433,203
$ 33,142,658	$ (88,474,653)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (93,781,317)
$ 15,624,190	$ (46,890,658)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/26 & 12/1/26

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.00805	(2)
$	0.00311	
$	0.00019	
$	0.01135	
	1.062699	
$	0.01206	
$	0.09776	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.12933	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2025 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	26,277,254
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	822,524,688
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	21,120,782
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 24,026,489
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 16,825,546

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2026

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	151,681,672
654,715,616	136,851,235
3,449,574	(22,283)
2,100,608	24,176,646
1,027,846	225,446
661,293,644	161,231,044
30,670,154	(9,549,372)
2,472,504	433,203
$ 33,142,658	$ (9,116,169)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (14,422,833)
$ 15,624,190	$ (7,211,417)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/25 (ACTUAL) & 12/1/25 (ASSUMED)

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.00034	(2)
$	0.00311	
$	0.00019	
$	0.00364	
	1.062699	
$	0.00387	
$	0.08956	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.12114	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Period: 6/01/2025 through 11/30/2025
ACTUAL

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)	
	100.00%		
$	0.08064		
	1.062699		
$	0.08570		
$	0.00034	(2)	0%
$	0.00311		
$	0.00019		
$	0.00364		
	1.062699		
$	0.00387		
			ROUNDING
$	0.08956		$ 0.00001
$	0.03158	(3), (5)	
$	0.00000	(4)	
$	0.12114		

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2024 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	706,417,743
2	Energy Procurement (Schedule 2, Line 2A, Column M)	685,698,006
	PJM Expenses (Schedule 2, Line 2B, Column M)	1,280,073
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	10,739,509
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,033,360
	Total Expenses to Recover	698,750,948
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	7,666,795
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	434,063
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 8,100,858
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	8,208,302
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 16,309,160

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2025

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
590,614,561	115,803,182
576,751,936	108,946,070
1,583,491	(303,418)
1,782,496	8,957,013
859,444	173,916
580,977,367	117,773,581
9,637,194	(1,970,399)
679,147	(245,084)
$ 10,316,341	$ (2,215,483)
6,603,351	1,604,951
$ 16,919,692	$ (610,532)
$ 8,459,846	$ (305,266)
$ 8,459,846	$ (305,266)

PPL ELECTRIC
TRANSMISSION SER
Report For The Perio

Line No.			Total
1	Revenues available for current expenses (Schedule 2, Column M, Lines 1, 6, 10 & 14	$	250,154,035
2	Actual PJM-Billed Transmission Service Expenses (Schedule 2, Column M, Lines 2, 7, 11 & 15)		251,907,507
3	Actual PJM Costs Directly Assigned (Schedule 2, Column M, Line 3)		14,109,161
4	Actual Net Metering Expenses (Schedule 2, Column M, Lines 4, 8, 12 & 16)		4,400,782
5	Over/(Under) Collection (Schedule 2, Column M, Lines 5, 9, 13 & 17)		(20,263,415)
5a	Revenue Adj. - Susquehanna Nuclear, LLC (1)		0
5b	Over/(Under) Collection (Line 5 + Line 5a)		(20,263,415)
6	Interest on Over/(Under) Collection (Schedule 5, Line 14, Columns D, F, H, J & L)		(1,158,586)
6A	Interim Rate Filing (2)		18,812,700
7	Over/(Under) Collection plus Interest (Excluding GRT) (Line 5b plus Li		(2,609,301)
8	Remaining E-Factor Balance (Schedule 3, Line 14, Columns B, D, F, I		(5,728,790)
9	Over/(Under) Collection (Excluding GRT) (Line 7 plus Line 8)	$	(8,338,091)

(1) Represents dollars paid by Susquehanna Nuclear, LLC for backup service related to a behind the meter data cer

(2) Represents the under-collection, including applicable interest, at September 30, 2024, as set forth on Schedule A

: UTILITIES CORPORATION
RVICE CHARGE RECONCILIATION
od April 1, 2024 to March 31, 2025

	Residential	Small Commercial & Industrial	Large Commercial & Industrial - Primary
$	208,504,605	$ 37,206,527	$ 2,780,224
	207,328,577	40,532,404	3,278,142
	14,109,161	-	-
	619,692	1,884,461	1,896,629
	(13,552,825)	(5,210,338)	(2,394,547)
	863,109	189,895	22,112
	(12,689,716)	(5,020,443)	(2,372,435)
	(760,316)	(267,696)	(117,093)
	15,779,145	2,410,452	897,977
	2,329,113	(2,877,687)	(1,591,551)
	(3,480,116)	(630,444)	(535,722)
$	(1,151,003)	$ (3,508,131)	$ (2,127,273)

nter. The adjustment was recorded in the GSC and TSC riders in May of 2024.

A, Line 4A of the Company's October 30, 2024 rate filing at Docket No. M-2024-3051913.

Large Commercial & Industrial - Transmission
$ 1,662,679
768,384
-
-
894,295
(1,075,116)
(180,821)
(13,481)
(274,874)
(469,176)
(1,082,508)
$ (1,551,684)

Line No.	
1	Transmission Service Charge
2	TCd = Total Demand-related Portion of Projected PJM-Billed Trans Service Expenses (Schedule B)
3	TCe = Total Energy-related Portion of Projected PJM-Billed Transn Service Expenses (Schedule B)
3A	Total Directly Assignable PJM Expenses - Residential only (Schedı
3B	Net Metering Expenses (Schedule B)
4	E = Experienced Net Over/(Under) Collections, Including Interest and Audit Adjustment (C), Net Prior Period Remaining Balance
5	Net Over(Under) Collection Amount
6	Total Amount to be Recovered (Line 2 plus Line 3 plus Line 3A plu
7	Total Amount to be Recovered, Including MFC (Line 6 times MFC)
8	S = Projected Total Retail KWH Sales to Customers
9	Billing Demand kW
10	Peak Load Contribution (MW)
11	Merchant Function Charge Factor (MFC) Residential Small Commercial & Industrial
12	$\frac{1}{(1 - T)}$ = (T = 5.9% Gross Receipts Tax)

13 TSC = Transmission Service Charge ($/ KWH)

Energy Rate ($/KWH) (w/o GRT)
Demand Rate ($/kW) (w/o GRT)

Energy Rate ($/KWH) (w/ GRT)
Demand Rate ($/kW) (w/ GRT)

(A) TSC=[TCe/S + TCd/S - E/S] x 1/(1-T)

(B) TSC=TSCd + TSCe
TSCd=[TCd/D] x 1/(1-T)
TSCe=[TCe/S-E/S] x 1/(1-T)

(C) Schedule 1 of the Transmission Service Charge Reconciliation Rep

(D) In accordance with the Commission's approval of PPL Electric's De
filing a new TSC to be effective for the 6-month period of June 1, 2

PPL ELECTRIC UTILITIES CORPORATION
COMPUTATION OF PROPOSED TRANSMISSION SERVIC
COMPUTATION PERIOD: JUNE 1, 2025 THROUGH NOVEM

		Total	
smission	$	135,974,385	$
nission		679,203	
ule B-1)		6,488,889	
		1,166,436	
		(8,338,091)	
		-	
		(8,338,091)	
s Line 3B less Line 5)	$	152,647,004	$
	$	155,494,198	$
		4,951,994,998	

1/(1 - .0231) =
1/(1 - .0023) =

x 1.062699

$

$

port

efault Service Program and Procurement Plan for the Period June 1, 2025 th
025 through November 30, 2025. The subsequent price period will be Dece

CE CHARGE
MBER 30, 2025

Residential		Small Commercial & Industrial		Large Commercial & Industrial - Primary	
(A)		(A)		(B)	
109,459,380	$	23,142,840	$	3,045,826	$
679,203		-		-	
6,488,889		-		-	
-		335,134		831,302	
(1,151,003)	C.1	(3,508,131)	C.2	(2,127,273)	C.3
		-		-	
(1,151,003)		(3,508,131)		(2,127,273)	
117,778,475	$	26,986,105	$	6,004,401	$
120,563,465	$	27,048,308	$	6,004,401	$
3,853,968,201	A1.1	910,091,326	A2.1	100,207,675	A3.1
				298,874	E.6
1.023646		1.002305			

0.03128	$	0.02972	$	-	$
			$	20.090	$
0.03324	$	0.03158	$	-	$
			$	21.350	$

ırough May 31, 2029 at Docket No. P-2024-3047290, PPL Electric is
mber 1, 2025 through November 30, 2026, for a 12-month period.

Large Commercial & Industrial - Transmission	
(B)	
326,339	
-	
-	
-	
(1,551,684)	C.4
-	
(1,551,684)	
1,878,023	
1,878,023	
87,727,796	A3.2
70.8	E.1 x 12

-
26.526

-
28.189

Schedule A

2024

Cashout goes out 5/31/24
Reconciled 3/31/24
Half of reconciliation hits 6/1/24
Other half hits 12/1/24

Excess generation 6/1/23 - 5/31/24
Net metering expenses April 2023 - March 2024

2025

Cashout goes out 5/31/25
Reconciled 3/31/25
Half of reconciliation hits 6/1/25
Other half hits 12/1/25

Excess generation 6/1/24 - 5/31/25
Net metering expenses April 2024 - March 2025

2026

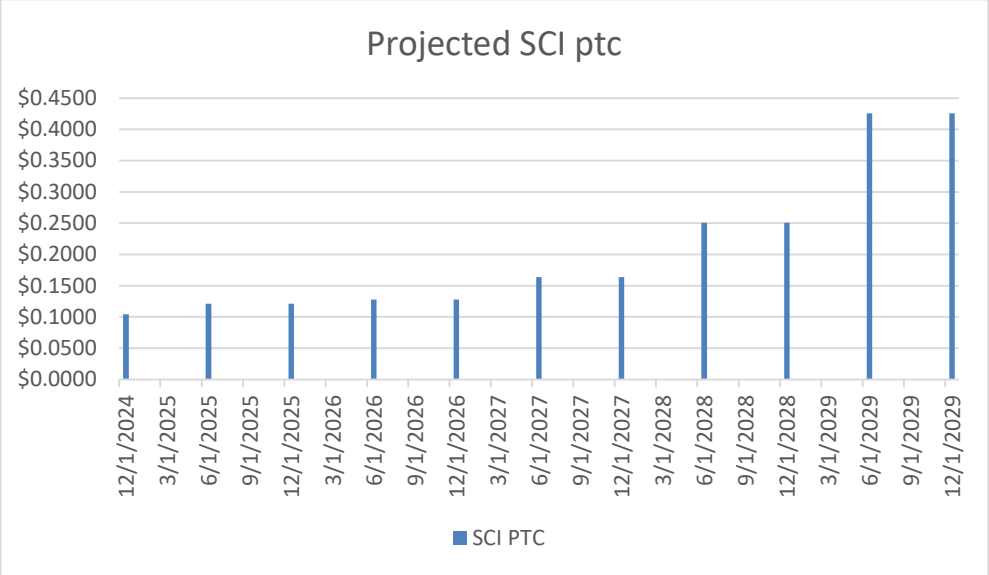
Cashout goes out 5/31/26
Reconciled 3/31/26
Half of reconciliation hits 6/1/26
Other half hits 12/1/26

Excess generation 6/1/25 - 5/31/26
Net metering expenses April 2025 - March 2026

PROJECTED:	12/1/2024	6/1/2025	12/1/2025	6/1/2026
SCI PTC	$ 0.10446	0.12114	$ 0.12114	$ 0.12760

PROJECTED:	2024	2025	20
SCI Net Metering Expense[(1)]	$ 10,350,518	$ 10,841,474	$

[(1)] Net Metering expense reflected in each SCI PTC is 1/2 of the amount filed in the March GSC-1 reconcil (ex. in June '24, the PTC included 1/2 the reconciliation amount for the GSC-1 reconciliation filed in Marc April '23-March '24)



12/1/2026	6/1/2027	12/1/2027	6/1/2028	12/1/2028	6/1/2029
$ 0.12760	$ 0.16381	$ 0.16381	$ 0.25083	$ 0.25083	$ 0.42547

26	2027	2028	20
10,418,103	$ 71,448,216	$ 218,134,161	$

iation, includes expenses from April - March of year
:h '24, which included net metering expenses from

35.23%
590%

12/1/2029
$ 0.42547

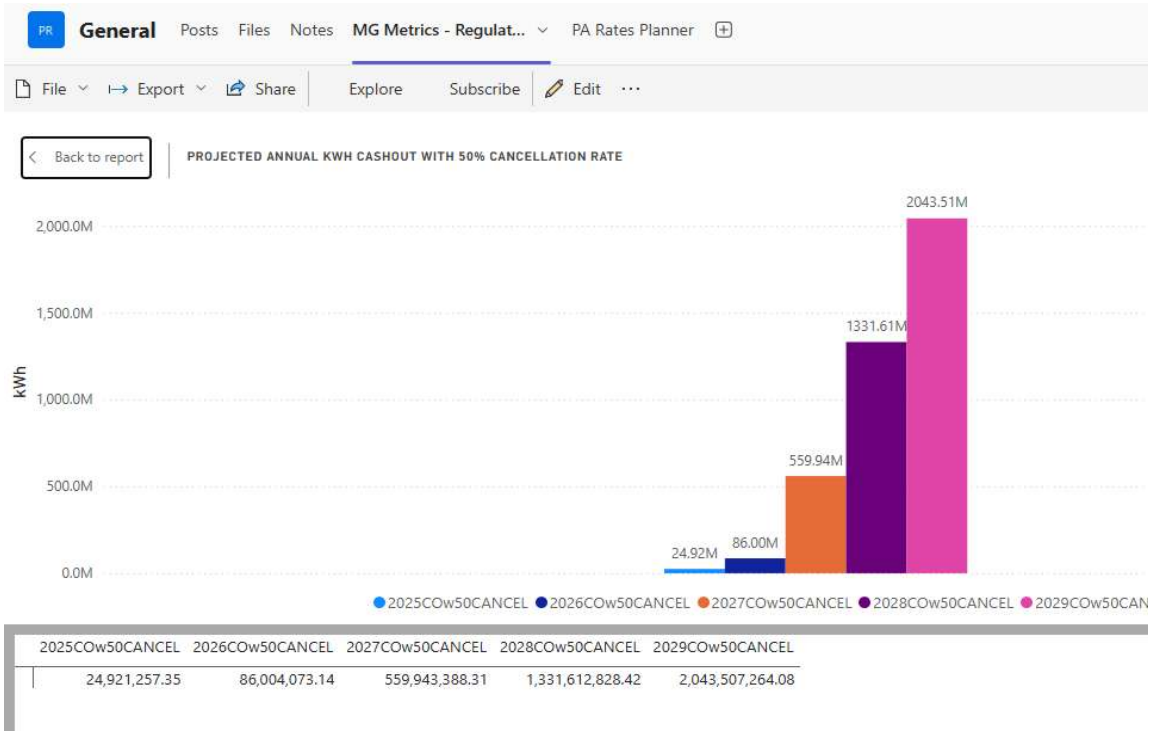
29
512,564,753

	Total
Projected 2025 kWh Bank	49,842,515
Projected 2025 kWh Bank w/ Cancellation Rate ~36%	24,921,257
Projected 2026 kWh Bank	172,008,146
Projected 2026 kWh Bank w/ Cancellation Rate ~36%	86,004,073
Projected 2027 kWh Bank	1,119,886,777
Projected 2027 kWh Bank w/ Cancellation Rate ~36%	559,943,388
Projected 2028 kWh Bank	2,663,225,657
Projected 2028 kWh Bank w/ Cancellation Rate ~36%	1,331,612,828
Projected 2029 kWh Bank	4,087,014,528
Projected 2029 kWh Bank w/ Cancellation Rate ~36%	2,043,507,264

Cancellation Rate	50%
Percentage of SCI Load in Queue	35%

[1] SCI accounts for roughly 38% of new service applications for solar (GS3) and the other are LP4 Interconnections team; but these are smaller applications than LP-4, so adjusting to 35% of total (Distribution Planning)

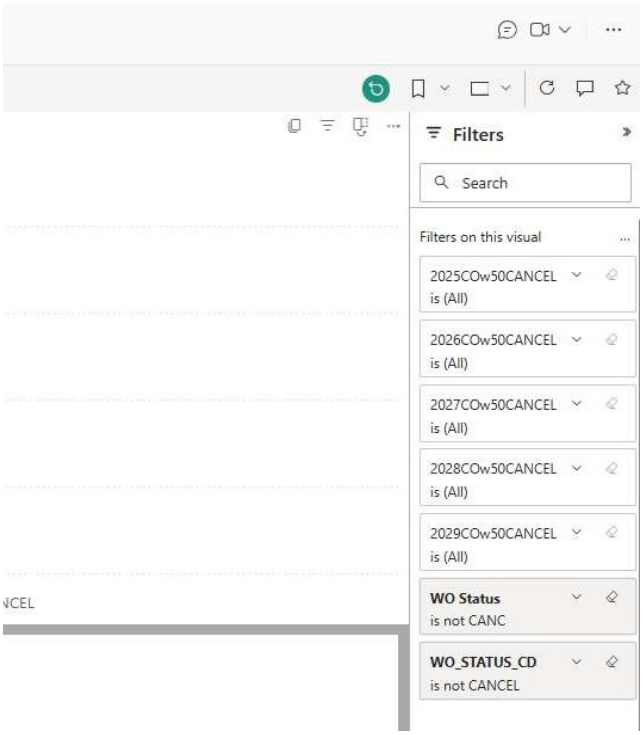
Source:



SCI Only(1)
49,842,515
24,921,257
172,008,146
86,004,073
1,119,886,777
559,943,388
2,663,225,657
1,331,612,828
4,087,014,528
2,043,507,264

cancellation rate now incorporated into kWH projection

according to the
kWh (estimate) per Micah Clarke



Year of Reconciliation/Cashout:	2024	2025	2026
SCI Excess kWh for MGs (kWh Cashed Out)			86,004,073
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114
Incremental SCI Net Metering Expense			$ 10,418,103
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 21,259,577
	^ Actual expense	*^ Actual expense*	

NOTES:
The amount of the net metering expense that is included in the reconciliation is only through March of a given
Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

2027	2028	2029	PTC at 12/1/30	
559,943,388	1,331,612,828	2,043,507,264		<-- Updated 8/20/25
$ 0.12760	$ 0.16381	$ 0.25083	$ 0.42547	
$ 71,448,216	$ 218,134,161	$ 512,564,753		
$ 82,289,690	$ 228,975,635	$ 523,406,227		<--cashout amount to be reflected

ı year and the cashout kWh is through May of that same year, so there is some estimation happening here with

in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each colur

timing

mn year

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/29 & 12/1/29

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.28671	(2)
$	0.00311	
$	0.00019	
$	0.29001	
	1.062699	
$	0.308193	
$	0.39389	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.42547	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2028 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	525,506,835
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	1,321,754,269
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(478,108,799)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (475,203,092)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (482,404,035)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2029

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	151,681,672	
654,715,616	136,851,235	
3,449,574	(22,283)	
2,100,608	523,406,227	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	660,460,625	
30,670,154	(508,778,953)	
2,472,504	433,203	
$ 33,142,658	$ (508,345,750)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (513,652,414)	
$ 15,624,190	$ (256,826,207)	
$ 15,624,190	$ (256,826,207)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/28 & 12/1/28

1	Average Full Requirements Price	
2	Times portion of Small Commerical and Industrial Load	
3	Total Weighted Full Requirements Price	
4	Multiplied by (1/(1-GRT))	*GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT	
6	E Factor Rate	
7	Administrative Charges Rate	
8	Merchant Function Charge (MFC) Rate	
9	Subtotal (Line 6 + Line 7 + Line 8)	
10	Multiplied by (1/(1-GRT))	
11	(E Factor + Admin Charges + MFC) x GRT	
12	Generation Supply Charge (Line 5 + Line 11)	
13	Transmission Service Charge (TSC)	
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.12237	(2)
$	0.00311	
$	0.00019	
$	0.12567	
	1.062699	
$	0.133549	
$	0.21925	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.25083	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2027 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	231,076,243
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	1,027,323,677
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(183,678,207)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (180,772,500)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (187,973,443)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2028

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	151,681,672	
654,715,616	136,851,235	
3,449,574	(22,283)	
2,100,608	228,975,635	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	366,030,033	
30,670,154	(214,348,361)	
2,472,504	433,203	
$ 33,142,658	$ (213,915,158)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (219,221,822)	
$ 15,624,190	$ (109,610,911)	
$ 15,624,190	$ (109,610,911)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/27 & 12/1/27

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.04049	(2)
$	0.00311	
$	0.00019	
$	0.04379	
	1.062699	
$	0.046536	
$	0.13223	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.16381	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2026 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	84,390,298
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	880,637,732
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(36,992,262)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (34,086,555)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (41,287,498)

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2027

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	151,681,672
654,715,616	136,851,235
3,449,574	(22,283)
2,100,608	82,289,690
1,027,846	225,446
661,293,644	219,344,088
30,670,154	(67,662,416)
2,472,504	433,203
$ 33,142,658	$ (67,229,213)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (72,535,877)
$ 15,624,190	$ (36,267,939)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/26 & 12/1/26

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.00642	(2)
$	0.00311	
$	0.00019	
$	0.00972	
	1.062699	
$	0.01033	
$	0.09603	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.12760	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2025 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	23,360,185
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	819,607,619
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	24,037,851
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 26,943,558
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 19,742,615

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2026

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	151,681,672
654,715,616	136,851,235
3,449,574	(22,283)
2,100,608	21,259,577
1,027,846	225,446
661,293,644	158,313,975
30,670,154	(6,632,303)
2,472,504	433,203
$ 33,142,658	$ (6,199,100)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (11,505,764)
$ 15,624,190	$ (5,752,882)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/25 (ACTUAL) & 12/1/25 (ASSUMED)

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.00034	(2)
$	0.00311	
$	0.00019	
$	0.00364	
	1.062699	
$	0.00387	
$	0.08956	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.12114	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Period: 6/01/2025 through 11/30/2025
ACTUAL

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)	
	100.00%		
$	0.08064		
	1.062699		
$	0.08570		
$	0.00034	(2)	0%
$	0.00311		
$	0.00019		
$	0.00364		
	1.062699		
$	0.00387		
			ROUNDING
$	0.08956		$ 0.00001
$	0.03158	(3), (5)	
$	0.00000	(4)	
$	0.12114		

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2024 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	705,909,169
2	Energy Procurement (Schedule 2, Line 2A, Column M)	685,698,006
	PJM Expenses (Schedule 2, Line 2B, Column M)	1,280,073
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	10,739,509
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,033,360
	Total Expenses to Recover	698,750,948
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	7,158,221
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	406,091
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 7,564,312
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	8,716,876
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 16,281,188

Schedule 1

)N
)NCILIATION
31, 2025*

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
590,099,010	115,810,159
576,751,936	108,946,070
1,583,491	(303,418)
1,782,496	8,957,013
859,444	173,916
580,977,367	117,773,581
9,121,643	(1,963,422)
650,791	(244,700)
$ 9,772,434	$ (2,208,122)
7,118,902	1,597,974
$ 16,891,336	$ (610,148)
$ 8,445,668	$ (305,074)

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2024 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	706,417,743
2	Energy Procurement (Schedule 2, Line 2A, Column M)	685,698,006
	PJM Expenses (Schedule 2, Line 2B, Column M)	1,280,073
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	10,739,509
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,033,360
	Total Expenses to Recover	698,750,948
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	7,666,795
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	434,063
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 8,100,858
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	8,208,302
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 16,309,160

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2025

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
590,614,561	115,803,182
576,751,936	108,946,070
1,583,491	(303,418)
1,782,496	8,957,013
859,444	173,916
580,977,367	117,773,581
9,637,194	(1,970,399)
679,147	(245,084)
$ 10,316,341	$ (2,215,483)
6,603,351	1,604,951
$ 16,919,692	$ (610,532)
$ 8,459,846	$ (305,266)
$ 8,459,846	$ (305,266)

PPL ELECTRIC
TRANSMISSION SER
Report For The Perio

Line No.		Total
1	Revenues available for current expenses (Schedule 2, Column M, Lines 1, 6, 10 & 14	$ 250,154,035
2	Actual PJM-Billed Transmission Service Expenses (Schedule 2, Column M, Lines 2, 7, 11 & 15)	251,907,507
3	Actual PJM Costs Directly Assigned (Schedule 2, Column M, Line 3)	14,109,161
4	Actual Net Metering Expenses (Schedule 2, Column M, Lines 4, 8, 12 & 16)	4,400,782
5	Over/(Under) Collection (Schedule 2, Column M, Lines 5, 9, 13 & 17)	(20,263,415)
5a	Revenue Adj. - Susquehanna Nuclear, LLC (1)	0
5b	Over/(Under) Collection (Line 5 + Line 5a)	(20,263,415)
6	Interest on Over/(Under) Collection (Schedule 5, Line 14, Columns D, F, H, J & L)	(1,158,586)
6A	Interim Rate Filing (2)	18,812,700
7	Over/(Under) Collection plus Interest (Excluding GRT) (Line 5b plus Li	(2,609,301)
8	Remaining E-Factor Balance (Schedule 3, Line 14, Columns B, D, F, I	(5,728,790)
9	Over/(Under) Collection (Excluding GRT) (Line 7 plus Line 8)	$ (8,338,091)

(1) Represents dollars paid by Susquehanna Nuclear, LLC for backup service related to a behind the meter data cer

(2) Represents the under-collection, including applicable interest, at September 30, 2024, as set forth on Schedule A

: UTILITIES CORPORATION
RVICE CHARGE RECONCILIATION
od April 1, 2024 to March 31, 2025

	Residential	Small Commercial & Industrial	Large Commercial & Industrial - Primary
$	208,504,605	$ 37,206,527	$ 2,780,224
	207,328,577	40,532,404	3,278,142
	14,109,161	-	-
	619,692	1,884,461	1,896,629
	(13,552,825)	(5,210,338)	(2,394,547)
	863,109	189,895	22,112
	(12,689,716)	(5,020,443)	(2,372,435)
	(760,316)	(267,696)	(117,093)
	15,779,145	2,410,452	897,977
	2,329,113	(2,877,687)	(1,591,551)
	(3,480,116)	(630,444)	(535,722)
$	(1,151,003)	$ (3,508,131)	$ (2,127,273)

nter. The adjustment was recorded in the GSC and TSC riders in May of 2024.

A, Line 4A of the Company's October 30, 2024 rate filing at Docket No. M-2024-3051913.

Large Commercial & Industrial - Transmission
$ 1,662,679
768,384
-
-
894,295
(1,075,116)
(180,821)
(13,481)
(274,874)
(469,176)
(1,082,508)
$ (1,551,684)

Line No.	
1	Transmission Service Charge
2	TCd = Total Demand-related Portion of Projected PJM-Billed Trans Service Expenses (Schedule B)
3	TCe = Total Energy-related Portion of Projected PJM-Billed Transn Service Expenses (Schedule B)
3A	Total Directly Assignable PJM Expenses - Residential only (Schedı
3B	Net Metering Expenses (Schedule B)
4	E = Experienced Net Over/(Under) Collections, Including Interest and Audit Adjustment (C), Net Prior Period Remaining Balance
5	Net Over(Under) Collection Amount
6	Total Amount to be Recovered (Line 2 plus Line 3 plus Line 3A plu
7	Total Amount to be Recovered, Including MFC (Line 6 times MFC)
8	S = Projected Total Retail KWH Sales to Customers
9	Billing Demand kW
10	Peak Load Contribution (MW)
11	Merchant Function Charge Factor (MFC) Residential Small Commercial & Industrial
12	$\frac{1}{(1 - T)}$ = (T = 5.9% Gross Receipts Tax)

13 TSC = Transmission Service Charge ($/ KWH)

Energy Rate ($/KWH) (w/o GRT)
Demand Rate ($/kW) (w/o GRT)

Energy Rate ($/KWH) (w/ GRT)
Demand Rate ($/kW) (w/ GRT)

(A) TSC=[TCe/S + TCd/S - E/S] x 1/(1-T)

(B) TSC=TSCd + TSCe
TSCd=[TCd/D] x 1/(1-T)
TSCe=[TCe/S-E/S] x 1/(1-T)

(C) Schedule 1 of the Transmission Service Charge Reconciliation Rep

(D) In accordance with the Commission's approval of PPL Electric's De
filing a new TSC to be effective for the 6-month period of June 1, 2

PPL ELECTRIC UTILITIES CORPORATION
COMPUTATION OF PROPOSED TRANSMISSION SERVIC
COMPUTATION PERIOD: JUNE 1, 2025 THROUGH NOVEM

		Total	
smission	$	135,974,385	$
nission		679,203	
ule B-1)		6,488,889	
		1,166,436	
		(8,338,091)	
		-	
		(8,338,091)	
s Line 3B less Line 5)	$	152,647,004	$
	$	155,494,198	$
		4,951,994,998	

1/(1 - .0231) =
1/(1 - .0023) =

x 1.062699

$

$

port

efault Service Program and Procurement Plan for the Period June 1, 2025 th
025 through November 30, 2025. The subsequent price period will be Dece

CE CHARGE
MBER 30, 2025

Residential		Small Commercial & Industrial		Large Commercial & Industrial - Primary	
(A)		(A)		(B)	
109,459,380	$	23,142,840	$	3,045,826	$
679,203		-		-	
6,488,889		-		-	
-		335,134		831,302	
(1,151,003)	C.1	(3,508,131)	C.2	(2,127,273)	C.3
		-		-	
(1,151,003)		(3,508,131)		(2,127,273)	
117,778,475	$	26,986,105	$	6,004,401	$
120,563,465	$	27,048,308	$	6,004,401	$
3,853,968,201	A1.1	910,091,326	A2.1	100,207,675	A3.1
				298,874	E.6
1.023646		1.002305			

0.03128	$	0.02972	$	-	$
			$	20.090	$
0.03324	$	0.03158	$	-	$
			$	21.350	$

ırough May 31, 2029 at Docket No. P-2024-3047290, PPL Electric is
mber 1, 2025 through November 30, 2026, for a 12-month period.

Large Commercial & Industrial - Transmission	
(B)	
326,339	
-	
-	
-	
(1,551,684)	C.4
-	
(1,551,684)	
1,878,023	
1,878,023	
87,727,796	A3.2
70.8	E.1 x 12

-
26.526

-
28.189

Schedule A

2024

Cashout goes out 5/31/24
Reconciled 3/31/24
Half of reconciliation hits 6/1/24
Other half hits 12/1/24

Excess generation 6/1/23 - 5/31/24
Net metering expenses April 2023 - March 2024

2025

Cashout goes out 5/31/25
Reconciled 3/31/25
Half of reconciliation hits 6/1/25
Other half hits 12/1/25

Excess generation 6/1/24 - 5/31/25
Net metering expenses April 2024 - March 2025

2026

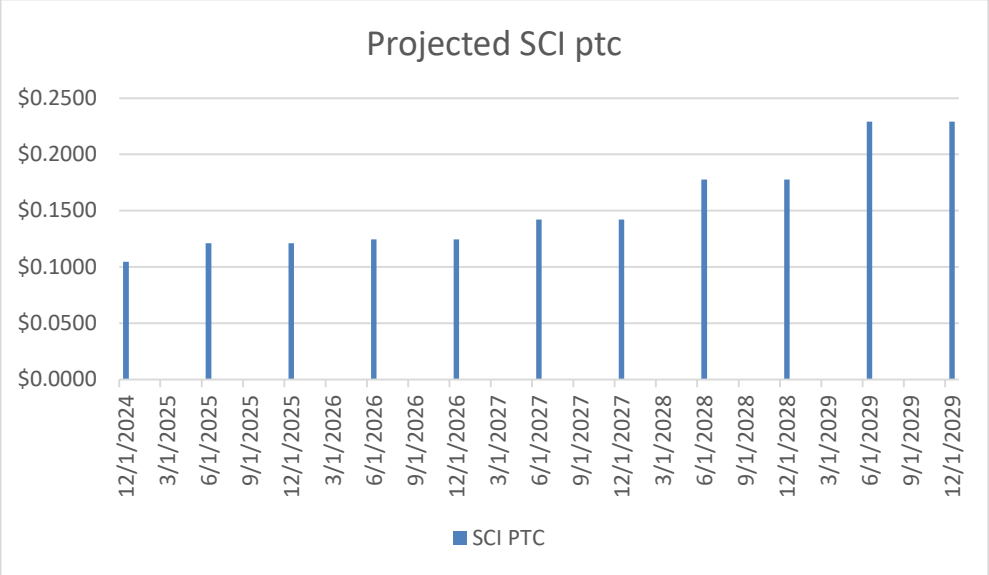
Cashout goes out 5/31/26
Reconciled 3/31/26
Half of reconciliation hits 6/1/26
Other half hits 12/1/26

Excess generation 6/1/25 - 5/31/26
Net metering expenses April 2025 - March 2026

PROJECTED:	12/1/2024	6/1/2025	12/1/2025	6/1/2026
SCI PTC	$ 0.10446	0.12114	$ 0.12114	$ 0.12451

PROJECTED:	2024	2025	20
SCI Net Metering Expense[(1)]	$ 10,350,518	$ 10,841,474	$

[(1)] Net Metering expense reflected in each SCI PTC is 1/2 of the amount filed in the March GSC-1 reconcil (ex. in June '24, the PTC included 1/2 the reconciliation amount for the GSC-1 reconciliation filed in Marc April '23-March '24)



12/1/2026	6/1/2027	12/1/2027	6/1/2028	12/1/2028	6/1/2029
$ 0.12451	$ 0.14210	$ 0.14210	$ 0.17755	$ 0.17755	$ 0.22904

26	2027	2028	20
5,209,052	$ 34,858,996	$ 94,611,757	$

iation, includes expenses from April - March of year
:h '24, which included net metering expenses from

17.31%
237%

12/1/2029
$ 0.22904

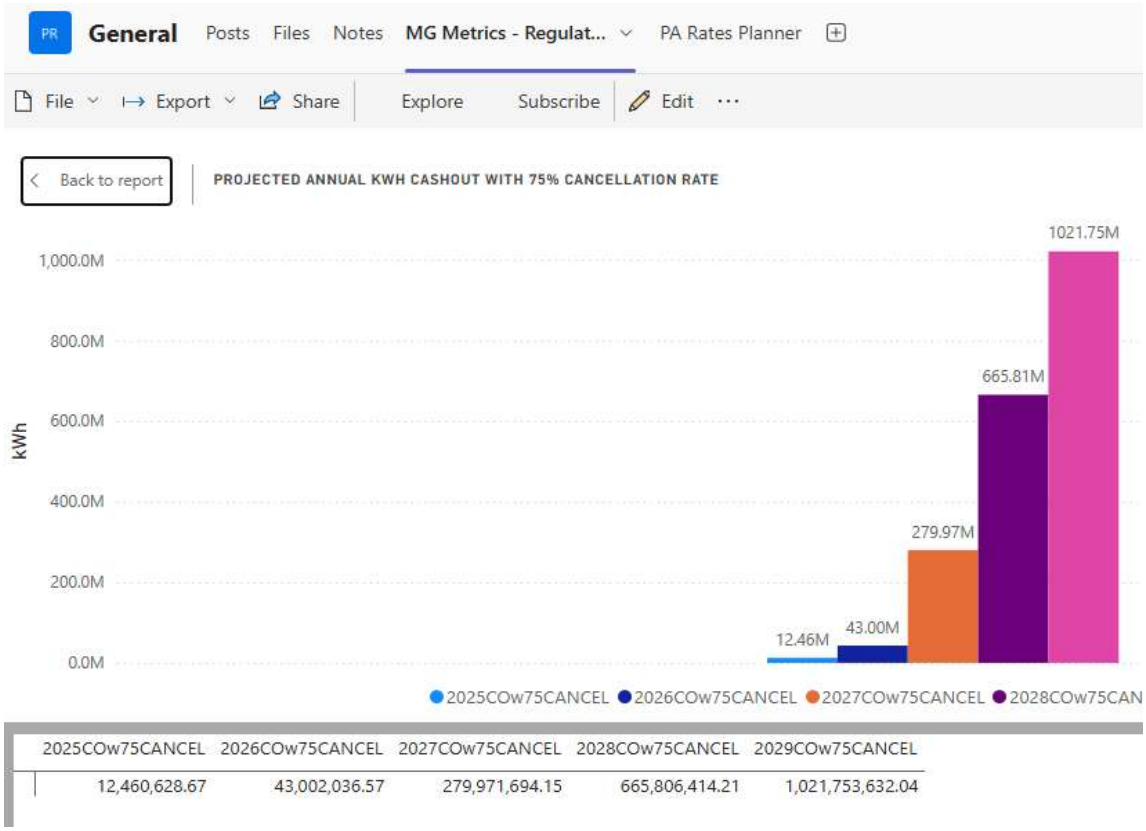
29
181,415,423

	Total
Projected 2025 kWh Bank	49,842,515
Projected 2025 kWh Bank w/ Cancellation Rate ~36%	12,460,629
Projected 2026 kWh Bank	172,008,146
Projected 2026 kWh Bank w/ Cancellation Rate ~36%	43,002,037
Projected 2027 kWh Bank	1,119,886,777
Projected 2027 kWh Bank w/ Cancellation Rate ~36%	279,971,694
Projected 2028 kWh Bank	2,663,225,657
Projected 2028 kWh Bank w/ Cancellation Rate ~36%	665,806,414
Projected 2029 kWh Bank	4,087,014,528
Projected 2029 kWh Bank w/ Cancellation Rate ~36%	1,021,753,632

Cancellation Rate	75%
Percentage of SCI Load in Queue	35%

[1] SCI accounts for roughly 38% of new service applications for solar (GS3) and the other are LP4 Interconnections team; but these are smaller applications than LP-4, so adjusting to 35% of total (Distribution Planning)

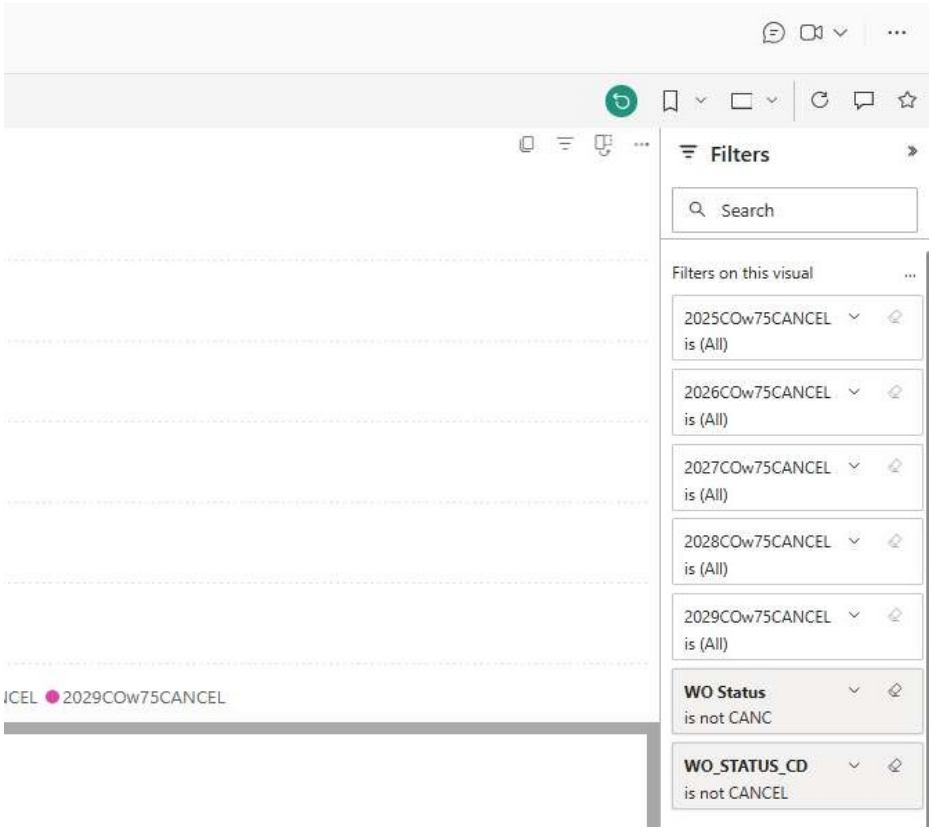
Source:



SCI Only(1)
49,842,515
12,460,629
172,008,146
43,002,037
1,119,886,777
279,971,694
2,663,225,657
665,806,414
4,087,014,528
1,021,753,632

cancellation rate now incorporated into kWH projection

according to the
kWh (estimate) per Micah Clarke



Year of Reconciliation/Cashout:	2024	2025	2026
SCI Excess kWh for MGs (kWh Cashed Out)	90,905,656	103,366,285	43,002,037
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114
Incremental SCI Net Metering Expense			$ 5,209,052
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 16,050,526
	^ Actual expense	*^ Actual expense*	

NOTES:
The amount of the net metering expense that is included in the reconciliation is only through March of a given Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

2027	2028	2029	PTC at 12/1/30	
279,971,694	665,806,414	1,021,753,632		<-- Updated 8/20/25
$ 0.12451	$ 0.14210	$ 0.17755	$ 0.22904	
$ 34,858,996	$ 94,611,757	$ 181,415,423		
$ 45,700,470	$ 105,453,231	$ 192,256,897		<--cashout amount to be reflected

ı year and the cashout kWh is through May of that same year, so there is some estimation happening here w

in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each colur

ith timing

ɱn year

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/29 & 12/1/29

1	Average Full Requirements Price	
2	Times portion of Small Commerical and Industrial Load	
3	Total Weighted Full Requirements Price	
4	Multiplied by (1/(1-GRT))	*GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT	
6	E Factor Rate	
7	Administrative Charges Rate	
8	Merchant Function Charge (MFC) Rate	
9	Subtotal (Line 6 + Line 7 + Line 8)	
10	Multiplied by (1/(1-GRT))	
11	(E Factor + Admin Charges + MFC) x GRT	
12	Generation Supply Charge (Line 5 + Line 11)	
13	Transmission Service Charge (TSC)	
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.10187	(2)
$	0.00311	
$	0.00019	
$	0.10517	
	1.062699	
$	0.111764	
$	0.19746	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.22904	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2028 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	194,357,505
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	990,604,939
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(146,959,469)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (144,053,762)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (151,254,705)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2029

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	151,681,672	
654,715,616	136,851,235	
3,449,574	(22,283)	
2,100,608	192,256,897	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	329,311,295	
30,670,154	(177,629,623)	
2,472,504	433,203	
$ 33,142,658	$ (177,196,420)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (182,503,084)	
$ 15,624,190	$ (91,251,542)	
$ 15,624,190	$ (91,251,542)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/28 & 12/1/28

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.05342	(2)
$	0.00311	
$	0.00019	
$	0.05672	
	1.062699	
$	0.060276	
$	0.14597	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.17755	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2027 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	107,553,839
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	903,801,273
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(60,155,803)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (57,250,096)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (64,451,039)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2028

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed		
691,963,798	151,681,672		
654,715,616	136,851,235		
3,449,574	(22,283)		
2,100,608	105,453,231	<-- Linked to Net Metering Expense	
1,027,846	225,446		
661,293,644	242,507,629		
30,670,154	(90,825,957)		359,461,123.26
2,472,504	433,203		
$ 33,142,658	$ (90,392,754)		
(1,894,279)	(5,306,664)		
$ 31,248,379	$ (95,699,418)		
$ 15,624,190	$ (47,849,709)		
$ 15,624,190	$ (47,849,709)		

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/27 & 12/1/27

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.02006	(2)
$	0.00311	
$	0.00019	
$	0.02336	
	1.062699	
$	0.024825	
$	0.11052	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.14210	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2026 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	47,801,078
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	844,048,512
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(403,042)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 2,502,665
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (4,698,278)

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2027

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	151,681,672
654,715,616	136,851,235
3,449,574	(22,283)
2,100,608	45,700,470
1,027,846	225,446
661,293,644	182,754,868
30,670,154	(31,073,196)
2,472,504	433,203
$ 33,142,658	$ (30,639,993)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (35,946,657)
$ 15,624,190	$ (17,973,328)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/26 & 12/1/26

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.00351	(2)
$	0.00311	
$	0.00019	
$	0.00681	
	1.062699	
$	0.00724	
$	0.09294	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.12451	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2025 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,645,470
2	Energy Procurement (Schedule 2, Line 2A, Column M)	791,566,851
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	18,151,134
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	814,398,568
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	29,246,902
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 32,152,609
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 24,951,666

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2026

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	151,681,672
654,715,616	136,851,235
3,449,574	(22,283)
2,100,608	16,050,526
1,027,846	225,446
661,293,644	153,104,924
30,670,154	(1,423,252)
2,472,504	433,203
$ 33,142,658	$ (990,049)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (6,296,713)
$ 15,624,190	$ (3,148,356)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/25 (ACTUAL) & 12/1/25 (ASSUMED)

1	Average Full Requirements Price	
2	Times portion of Small Commerical and Industrial Load	
3	Total Weighted Full Requirements Price	
4	Multiplied by (1/(1-GRT))	*GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT	
6	E Factor Rate	
7	Administrative Charges Rate	
8	Merchant Function Charge (MFC) Rate	
9	Subtotal (Line 6 + Line 7 + Line 8)	
10	Multiplied by (1/(1-GRT))	
11	(E Factor + Admin Charges + MFC) x GRT	
12	Generation Supply Charge (Line 5 + Line 11)	
13	Transmission Service Charge (TSC)	
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.00034	(2)
$	0.00311	
$	0.00019	
$	0.00364	
	1.062699	
$	0.00387	
$	0.08956	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.12114	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") REC(
Report for the Period April 1, 2024 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	706,417,743
2	Energy Procurement (Schedule 2, Line 2A, Column M)	685,698,006
	PJM Expenses (Schedule 2, Line 2B, Column M)	1,280,073
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	10,739,509
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,033,360
	Total Expenses to Recover	698,750,948
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	7,666,795
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	434,063
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 8,100,858
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	8,208,302
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 16,309,160

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2025

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
590,614,561	115,803,182
576,751,936	108,946,070
1,583,491	(303,418)
1,782,496	8,957,013
859,444	173,916
580,977,367	117,773,581
9,637,194	(1,970,399)
679,147	(245,084)
$ 10,316,341	$ (2,215,483)
6,603,351	1,604,951
$ 16,919,692	$ (610,532)
$ 8,459,846	$ (305,266)
$ 8,459,846	$ (305,266)

PPL ELECTRIC
TRANSMISSION SER
Report For The Perio

Line No.			Total
1	Revenues available for current expenses (Schedule 2, Column M, Lines 1, 6, 10 & 14	$	250,154,035
2	Actual PJM-Billed Transmission Service Expenses (Schedule 2, Column M, Lines 2, 7, 11 & 15)		251,907,507
3	Actual PJM Costs Directly Assigned (Schedule 2, Column M, Line 3)		14,109,161
4	Actual Net Metering Expenses (Schedule 2, Column M, Lines 4, 8, 12 & 16)		4,400,782
5	Over/(Under) Collection (Schedule 2, Column M, Lines 5, 9, 13 & 17)		(20,263,415)
5a	Revenue Adj. - Susquehanna Nuclear, LLC (1)		0
5b	Over/(Under) Collection (Line 5 + Line 5a)		(20,263,415)
6	Interest on Over/(Under) Collection (Schedule 5, Line 14, Columns D, F, H, J & L)		(1,158,586)
6A	Interim Rate Filing (2)		18,812,700
7	Over/(Under) Collection plus Interest (Excluding GRT) (Line 5b plus Li		(2,609,301)
8	Remaining E-Factor Balance (Schedule 3, Line 14, Columns B, D, F, I		(5,728,790)
9	Over/(Under) Collection (Excluding GRT) (Line 7 plus Line 8)	$	(8,338,091)

(1) Represents dollars paid by Susquehanna Nuclear, LLC for backup service related to a behind the meter data cer

(2) Represents the under-collection, including applicable interest, at September 30, 2024, as set forth on Schedule A

: UTILITIES CORPORATION
RVICE CHARGE RECONCILIATION
od April 1, 2024 to March 31, 2025

	Residential	Small Commercial & Industrial	Large Commercial & Industrial - Primary
$	208,504,605	$ 37,206,527	$ 2,780,224
	207,328,577	40,532,404	3,278,142
	14,109,161	-	-
	619,692	1,884,461	1,896,629
	(13,552,825)	(5,210,338)	(2,394,547)
	863,109	189,895	22,112
	(12,689,716)	(5,020,443)	(2,372,435)
	(760,316)	(267,696)	(117,093)
	15,779,145	2,410,452	897,977
	2,329,113	(2,877,687)	(1,591,551)
	(3,480,116)	(630,444)	(535,722)
$	(1,151,003)	$ (3,508,131)	$ (2,127,273)

nter. The adjustment was recorded in the GSC and TSC riders in May of 2024.

A, Line 4A of the Company's October 30, 2024 rate filing at Docket No. M-2024-3051913.

Large Commercial & Industrial - Transmission
$ 1,662,679
768,384
-
-
894,295
(1,075,116)
(180,821)
(13,481)
(274,874)
(469,176)
(1,082,508)
$ (1,551,684)

Line No.	
1	Transmission Service Charge
2	TCd = Total Demand-related Portion of Projected PJM-Billed Trans Service Expenses (Schedule B)
3	TCe = Total Energy-related Portion of Projected PJM-Billed Transn Service Expenses (Schedule B)
3A	Total Directly Assignable PJM Expenses - Residential only (Schedı
3B	Net Metering Expenses (Schedule B)
4	E = Experienced Net Over/(Under) Collections, Including Interest and Audit Adjustment (C), Net Prior Period Remaining Balance
5	Net Over(Under) Collection Amount
6	Total Amount to be Recovered (Line 2 plus Line 3 plus Line 3A plu
7	Total Amount to be Recovered, Including MFC (Line 6 times MFC)
8	S = Projected Total Retail KWH Sales to Customers
9	Billing Demand kW
10	Peak Load Contribution (MW)
11	Merchant Function Charge Factor (MFC) Residential Small Commercial & Industrial
12	$\frac{1}{(1 - T)}$ = (T = 5.9% Gross Receipts Tax)

13 TSC = Transmission Service Charge ($/ KWH)

Energy Rate ($/KWH) (w/o GRT)
Demand Rate ($/kW) (w/o GRT)

Energy Rate ($/KWH) (w/ GRT)
Demand Rate ($/kW) (w/ GRT)

(A) TSC=[TCe/S + TCd/S - E/S] x 1/(1-T)

(B) TSC=TSCd + TSCe
TSCd=[TCd/D] x 1/(1-T)
TSCe=[TCe/S-E/S] x 1/(1-T)

(C) Schedule 1 of the Transmission Service Charge Reconciliation Rep

(D) In accordance with the Commission's approval of PPL Electric's De
filing a new TSC to be effective for the 6-month period of June 1, 2

PPL ELECTRIC UTILITIES CORPORATION
COMPUTATION OF PROPOSED TRANSMISSION SERVIC
COMPUTATION PERIOD: JUNE 1, 2025 THROUGH NOVEM

		Total	
smission	$	135,974,385	$
nission		679,203	
ule B-1)		6,488,889	
		1,166,436	
		(8,338,091)	
		-	
		(8,338,091)	
s Line 3B less Line 5)	$	152,647,004	$
	$	155,494,198	$
		4,951,994,998	

1/(1 - .0231) =
1/(1 - .0023) =

x 1.062699

$

$

port

efault Service Program and Procurement Plan for the Period June 1, 2025 th
025 through November 30, 2025. The subsequent price period will be Dece

CE CHARGE
MBER 30, 2025

Residential		Small Commercial & Industrial		Large Commercial & Industrial - Primary	
(A)		(A)		(B)	
109,459,380	$	23,142,840	$	3,045,826	$
679,203		-		-	
6,488,889		-		-	
-		335,134		831,302	
(1,151,003)	C.1	(3,508,131)	C.2	(2,127,273)	C.3
		-		-	
(1,151,003)		(3,508,131)		(2,127,273)	
117,778,475	$	26,986,105	$	6,004,401	$
120,563,465	$	27,048,308	$	6,004,401	$
3,853,968,201	A1.1	910,091,326	A2.1	100,207,675	A3.1
				298,874	E.6
1.023646		1.002305			

0.03128	$	0.02972	$	-	$
			$	20.090	$
0.03324	$	0.03158	$	-	$
			$	21.350	$

ırough May 31, 2029 at Docket No. P-2024-3047290, PPL Electric is
mber 1, 2025 through November 30, 2026, for a 12-month period.

Large Commercial & Industrial - Transmission	
(B)	
326,339	
-	
-	
-	
(1,551,684)	C.4
-	
(1,551,684)	
1,878,023	
1,878,023	
87,727,796	A3.2
70.8	E.1 x 12

-
26.526

-
28.189

Schedule A

2024

Cashout goes out 5/31/24
Reconciled 3/31/24
Half of reconciliation hits 6/1/24
Other half hits 12/1/24

Excess generation 6/1/23 - 5/31/24
Net metering expenses April 2023 - March 2024

2025

Cashout goes out 5/31/25
Reconciled 3/31/25
Half of reconciliation hits 6/1/25
Other half hits 12/1/25

Excess generation 6/1/24 - 5/31/25
Net metering expenses April 2024 - March 2025

2026

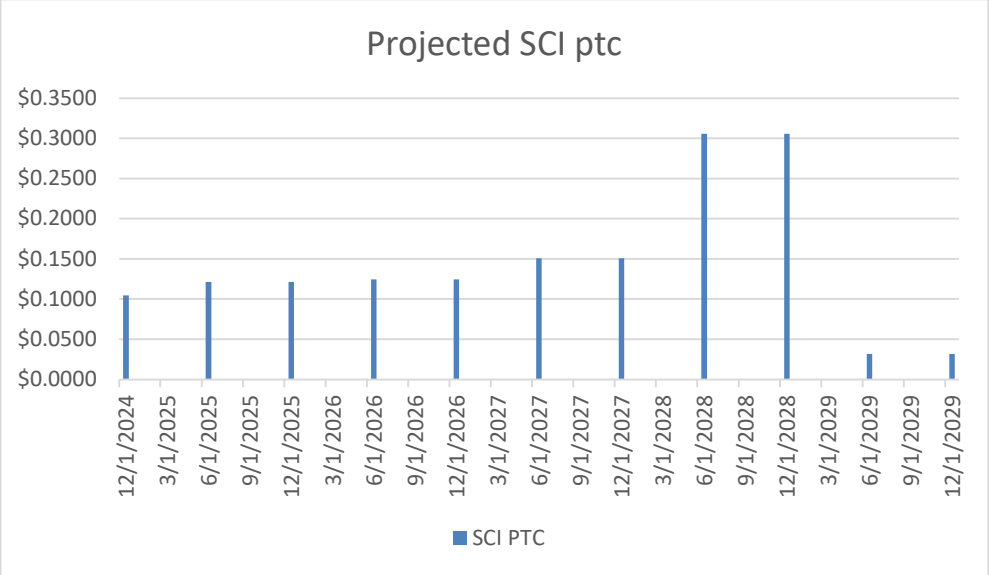
Cashout goes out 5/31/26
Reconciled 3/31/26
Half of reconciliation hits 6/1/26
Other half hits 12/1/26

Excess generation 6/1/25 - 5/31/26
Net metering expenses April 2025 - March 2026

PROJECTED:	12/1/2024	6/1/2025	12/1/2025	6/1/2026
SCI PTC	$ 0.10446	0.12114	$ 0.12114	$ 0.12437

PROJECTED:	2024	2025	20
SCI Net Metering Expense[(1)]	$ 10,350,518	$ 10,841,474	$

[(1)] Net Metering expense reflected in each SCI PTC is 1/2 of the amount filed in the March GSC-1 reconcil (ex. in June '24, the PTC included 1/2 the reconciliation amount for the GSC-1 reconciliation filed in Marc April '23-March '24)



12/1/2026	6/1/2027	12/1/2027	6/1/2028	12/1/2028	6/1/2029
$ 0.12437	$ 0.15064	$ 0.15064	$ 0.30562	$ 0.30562	$ 0.03158

26	2027	2028	20
5,401,106	$ 35,139,574	$ 137,476,269	$

iation, includes expenses from April - March of year
:h '24, which included net metering expenses from

24.35%
239%

12/1/2029
$ 0.03158

29
574,553,061

	Total
Projected 2025 kWh Bank	49,842,515
Projected 2025 kWh Bank w/ Cancellation Rate ~36%	31,899,209
Projected 2026 kWh Bank	172,008,146
Projected 2026 kWh Bank w/ Cancellation Rate ~36%	110,085,214
Projected 2027 kWh Bank	1,119,886,777
Projected 2027 kWh Bank w/ Cancellation Rate ~36%	716,727,537
Projected 2028 kWh Bank	2,663,225,657
Projected 2028 kWh Bank w/ Cancellation Rate ~36%	1,704,464,420
Projected 2029 kWh Bank	4,087,014,528
Projected 2029 kWh Bank w/ Cancellation Rate ~36%	2,615,689,298

Cancellation Rate	36%

17.3% Capacity Factor
49,842,515
31,899,209
69,667,956
44,587,492
441,473,228
282,542,866
1,426,007,698
912,644,927
2,937,464,726
1,879,977,425

cancellation rate now incorporated into kWH projection

Year of Reconciliation/Cashout:	2024	2025	2026
SCI Excess kWh for MGs (kWh Cashed Out)			44,587,492
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114
SCI Net Metering Expense from MGs			$ 5,401,106
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 16,242,580
	^ Actual expense	*^ Actual expense*	

PTC Premium to Wholesale Supply	$ 0.03544
Annual Premium Paid by Non NM Customers	$ 1,580,134

NOTES:
The amount of the net metering expense that is included in the reconciliation is only through March of a given Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

2027	2028	2029	2030	
282,542,866	912,644,927	1,879,977,425		<-- Updated 2/11/26
$ 0.12437	$ 0.15064	$ 0.30562	$ 0.03158	
$ 35,139,574	$ 137,476,269	$ 574,553,061		
$ 45,981,048	$ 148,317,743	$ 585,394,535		<--cashout amount to be reflected

$ 0.04072	$ 0.06672	$ 0.22032	<--PTC minus procurement rate
$ 11,504,348	$ 60,892,292	$ 414,198,666	

year and the cashout kWh is through May of that same year, so there is some estimation happening here wi

in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each colur

th timing

mn year

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/29 & 12/1/29

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	-	(1)
	100.00%	
$	-	
	1.062699	
$	-	
$	-	(2)
$	-	
$	-	
$	-	
	1.062699	
$	-	
$	-	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.03158	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2028 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	691,963,798
2	Energy Procurement (Schedule 2, Line 2A, Column M)	654,715,616
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	587,495,143
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	1,246,891,342
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(554,927,544)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (552,021,837)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (559,222,780)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2029

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	-	
654,715,616	-	
3,449,574	(22,283)	
2,100,608	585,394,535	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	585,597,698	
30,670,154	(585,597,698)	
2,472,504	433,203	
$ 33,142,658	$ (585,164,495)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (590,471,159)	
$ 15,624,190	$ (295,235,579)	
$ 15,624,190	$ (295,235,579)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/28 & 12/1/28

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08026	(1)
	100.00%	
$	0.08026	
	1.062699	
$	0.08530	
$	0.17088	(2)
$	0.00633	
$	0.00040	
$	0.17760	
	1.062699	
$	0.188740	
$	0.27404	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.30562	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2027 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	765,714,761
2	Energy Procurement (Schedule 2, Line 2A, Column M)	725,257,911
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	150,418,351
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	880,356,845
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(114,642,084)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (111,736,377)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (118,937,320)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2028

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	73,750,963	
654,715,616	70,542,295	
3,449,574	(22,283)	
2,100,608	148,317,743	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	219,063,201	
30,670,154	(145,312,238)	
2,472,504	433,203	
$ 33,142,658	$ (144,879,035)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (150,185,699)	
$ 15,624,190	$ (75,092,849)	
$ 15,624,190	$ (75,092,849)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/27 & 12/1/27

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.07896	(1)
	100.00%	
$	0.07896	
	1.062699	
$	0.08391	
$	0.02915	(2)
$	0.00369	
$	0.00023	
$	0.03307	
	1.062699	
$	0.035140	
$	0.11905	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.15064	

ROUNDING $ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2026 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	818,193,246
2	Energy Procurement (Schedule 2, Line 2A, Column M)	773,870,285
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	48,081,656
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	826,632,524
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(8,439,278)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (5,533,571)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (12,734,514)

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2027

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	126,229,448
654,715,616	119,154,669
3,449,574	(22,283)
2,100,608	45,981,048
1,027,846	225,446
661,293,644	165,338,880
30,670,154	(39,109,432)
2,472,504	433,203
$ 33,142,658	$ (38,676,229)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (43,982,893)
$ 15,624,190	$ (21,991,446)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/26 & 12/1/26

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.07872 (1)		
	100.00%		
$	0.07872		
	1.062699		
$	0.08365		
$	0.00522 (2)		
$	0.00318	$	0.00318
$	0.00020		0.00020
$	0.00861		
	1.062699		
$	0.00915		
		ROUNDING	
$	0.09280	$	0.00001
$	0.03158 (3), (5)		
$	0.00000 (4)		
$	0.12437		

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2025 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	841,669,785
2	Energy Procurement (Schedule 2, Line 2A, Column M)	792,228,542
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	18,343,188
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	815,252,313
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	26,417,472
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 29,323,179
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 22,122,236

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2026

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	149,705,987
654,715,616	137,512,926
3,449,574	(22,283)
2,100,608	16,242,580
1,027,846	225,446
661,293,644	153,958,669
30,670,154	(4,252,682)
2,472,504	433,203
$ 33,142,658	$ (3,819,479)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (9,126,143)
$ 15,624,190	$ (4,563,071)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/25 (ACTUAL) & 12/1/25 (ASSUMED)

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.00034	(2)
$	0.00311	
$	0.00019	
$	0.00364	
	1.062699	
$	0.00387	
$	0.08956	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.12114	

ROUNDING $ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

2024

Cashout goes out 5/31/24
Reconciled 3/31/24
Half of reconciliation hits 6/1/24
Other half hits 12/1/24

Excess generation 6/1/23 - 5/31/24
Net metering expenses April 2023 - March 2024

2025

Cashout goes out 5/31/25
Reconciled 3/31/25
Half of reconciliation hits 6/1/25
Other half hits 12/1/25

Excess generation 6/1/24 - 5/31/25
Net metering expenses April 2024 - March 2025

2026

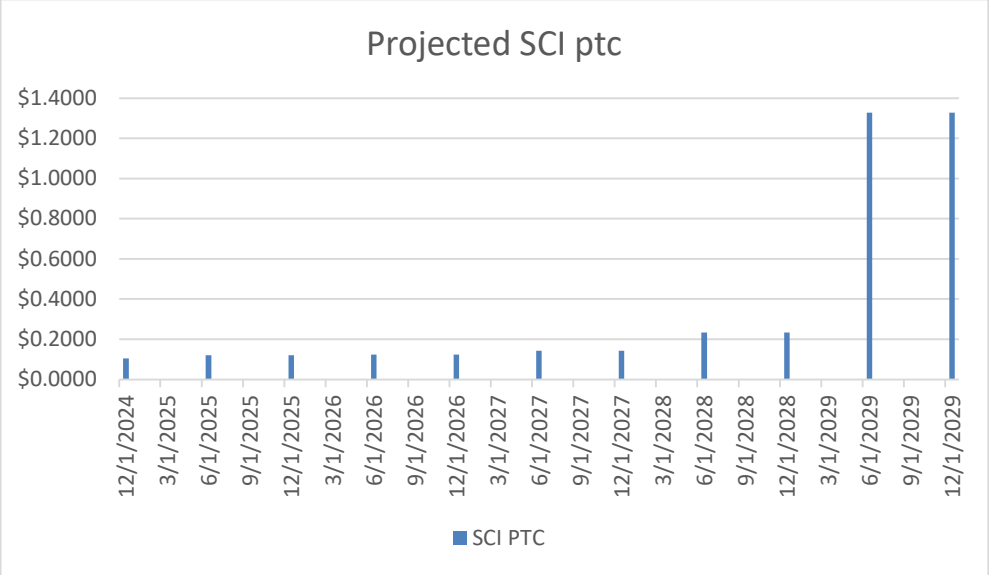
Cashout goes out 5/31/26
Reconciled 3/31/26
Half of reconciliation hits 6/1/26
Other half hits 12/1/26

Excess generation 6/1/25 - 5/31/26
Net metering expenses April 2025 - March 2026

PROJECTED:	12/1/2024	6/1/2025	12/1/2025	6/1/2026
SCI PTC	$ 0.10446	0.12114	$ 0.12114	$ 0.12354

PROJECTED:	2024	2025	20
SCI Net Metering Expense[(1)]	$ 10,350,518	$ 10,841,474	$

[(1)] Net Metering expense reflected in each SCI PTC is 1/2 of the amount filed in the March GSC-1 reconcil (ex. in June '24, the PTC included 1/2 the reconciliation amount for the GSC-1 reconciliation filed in Marc April '23-March '24)



12/1/2026	6/1/2027	12/1/2027	6/1/2028	12/1/2028	6/1/2029
$ 0.12354	$ 0.14358	$ 0.14358	$ 0.23423	$ 0.23423	$ 1.32804

26	2027	2028	20
4,219,614	$ 27,270,684	$ 102,375,232	$

iation, includes expenses from April - March of year
:h '24, which included net metering expenses from

18.53%
163%

12/1/2029
$ 1.32804

29
344,027,056

	Total
Projected 2025 kWh Bank	49,842,515
Projected 2025 kWh Bank w/ Cancellation Rate ~50%	24,921,257
Projected 2026 kWh Bank	172,008,146
Projected 2026 kWh Bank w/ Cancellation Rate ~50%	86,004,073
Projected 2027 kWh Bank	1,119,886,777
Projected 2027 kWh Bank w/ Cancellation Rate ~50%	559,943,388
Projected 2028 kWh Bank	2,663,225,657
Projected 2028 kWh Bank w/ Cancellation Rate ~50%	1,331,612,828
Projected 2029 kWh Bank	4,087,014,528
Projected 2029 kWh Bank w/ Cancellation Rate ~50%	2,043,507,264

Cancellation Rate	50%

17.3% Capacity Factor
49,842,515
24,921,257
69,667,956
34,833,978
441,473,228
220,736,614
1,426,007,698
713,003,849
2,937,464,726
1,468,732,363

cancellation rate now incorporated into kWH projection

Year of Reconciliation/Cashout:	2024	2025	2026
SCI Excess kWh for MGs (kWh Cashed Out)			34,833,978
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114
SCI Net Metering Expense from MGs			$ 4,219,614
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 15,061,088
	^ Actual expense	*^ Actual expense*	

PTC Premium to Wholesale Supply	$ 0.03544
Annual Premium Paid by Non NM Customers	$ 1,234,480

NOTES:

The amount of the net metering expense that is included in the reconciliation is only through March of a given Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

2027	2028	2029	2030	
220,736,614	713,003,849	1,468,732,363		<-- Updated 2/11/26
$ 0.12354	$ 0.14358	$ 0.23423	$ 1.32804	
$ 27,270,684	$ 102,375,232	$ 344,027,056		
$ 38,112,158	$ 113,216,706	$ 354,868,530		<--cashout amount to be reflected

$ 0.03990	$ 0.05974	$ 0.14955	<--PTC minus procurement rate
$ 8,807,704	$ 42,598,064	$ 219,649,720	

year and the cashout kWh is through May of that same year, so there is some estimation happening here wi

in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each colur

th timing

mn year

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/29 & 12/1/29

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08563	(1)
	100.00%	
$	0.08563	
	1.062699	
$	0.09100	
$	1.11603	(2)
$	0.01723	
$	0.00108	
$	1.13434	
	1.062699	
$	1.205461	
$	1.29646	
$	0.03158	(3), (5)
$	0.00000	(4)
$	1.32804	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2028 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	719,299,339
2	Energy Procurement (Schedule 2, Line 2A, Column M)	682,355,765
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	356,969,138
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	1,044,005,487
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(324,706,148)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (321,800,441)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (329,001,384)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2029

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	27,335,541	
654,715,616	27,640,149	
3,449,574	(22,283)	
2,100,608	354,868,530	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	382,711,843	
30,670,154	(355,376,302)	
2,472,504	433,203	
$ 33,142,658	$ (354,943,099)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (360,249,763)	
$ 15,624,190	$ (180,124,881)	
$ 15,624,190	$ (180,124,881)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/28 & 12/1/28

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.07969	(1)
	100.00%	
$	0.07969	
	1.062699	
$	0.08468	
$	0.10553	(2)
$	0.00516	
$	0.00032	
$	0.11101	
	1.062699	
$	0.117970	
$	0.20265	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.23423	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2027 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	782,385,726
2	Energy Procurement (Schedule 2, Line 2A, Column M)	740,660,220
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	115,317,314
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	860,658,117
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(78,272,391)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (75,366,684)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (82,567,627)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2028

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	90,421,928	
654,715,616	85,944,604	
3,449,574	(22,283)	
2,100,608	113,216,706	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	199,364,473	
30,670,154	(108,942,545)	
2,472,504	433,203	
$ 33,142,658	$ (108,509,342)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (113,816,006)	
$ 15,624,190	$ (56,908,003)	
$ 15,624,190	$ (56,908,003)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/27 & 12/1/27

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.07889	(1)
	100.00%	
$	0.07889	
	1.062699	
$	0.08384	
$	0.02274	(2)
$	0.00354	
$	0.00022	
$	0.02650	
	1.062699	
$	0.028164	
$	0.11200	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.14358	

ROUNDING $ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2026 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	823,348,934
2	Energy Procurement (Schedule 2, Line 2A, Column M)	778,638,637
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	40,212,766
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	823,531,987
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(183,052)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 2,722,655
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (4,478,288)

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2027

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	131,385,136
654,715,616	123,923,021
3,449,574	(22,283)
2,100,608	38,112,158
1,027,846	225,446
661,293,644	162,238,343
30,670,154	(30,853,206)
2,472,504	433,203
$ 33,142,658	$ (30,420,003)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (35,726,667)
$ 15,624,190	$ (17,863,334)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/26 & 12/1/26

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.07871 (1)		
	100.00%		
$	0.07871		
	1.062699		
$	0.08364		
$	0.00448 (2)		
$	0.00317	$	0.00317
$	0.00020		0.00020
$	0.00784		
	1.062699		
$	0.00833		
		ROUNDING	
$	0.09197	$	0.00001
$	0.03158 (3), (5)		
$	0.00000 (4)		
$	0.12354		

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2025 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	842,505,623
2	Energy Procurement (Schedule 2, Line 2A, Column M)	792,981,026
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	17,161,696
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	814,823,305
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	27,682,318
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 30,588,025
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 23,387,082

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2026

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	150,541,825
654,715,616	138,265,410
3,449,574	(22,283)
2,100,608	15,061,088
1,027,846	225,446
661,293,644	153,529,661
30,670,154	(2,987,836)
2,472,504	433,203
$ 33,142,658	$ (2,554,633)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (7,861,297)
$ 15,624,190	$ (3,930,648)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/25 (ACTUAL) & 12/1/25 (ASSUMED)

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.00034	(2)
$	0.00311	
$	0.00019	
$	0.00364	
	1.062699	
$	0.00387	
$	0.08956	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.12114	

ROUNDING $ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

2024

Cashout goes out 5/31/24
Reconciled 3/31/24
Half of reconciliation hits 6/1/24
Other half hits 12/1/24

Excess generation 6/1/23 - 5/31/24
Net metering expenses April 2023 - March 2024

2025

Cashout goes out 5/31/25
Reconciled 3/31/25
Half of reconciliation hits 6/1/25
Other half hits 12/1/25

Excess generation 6/1/24 - 5/31/25
Net metering expenses April 2024 - March 2025

2026

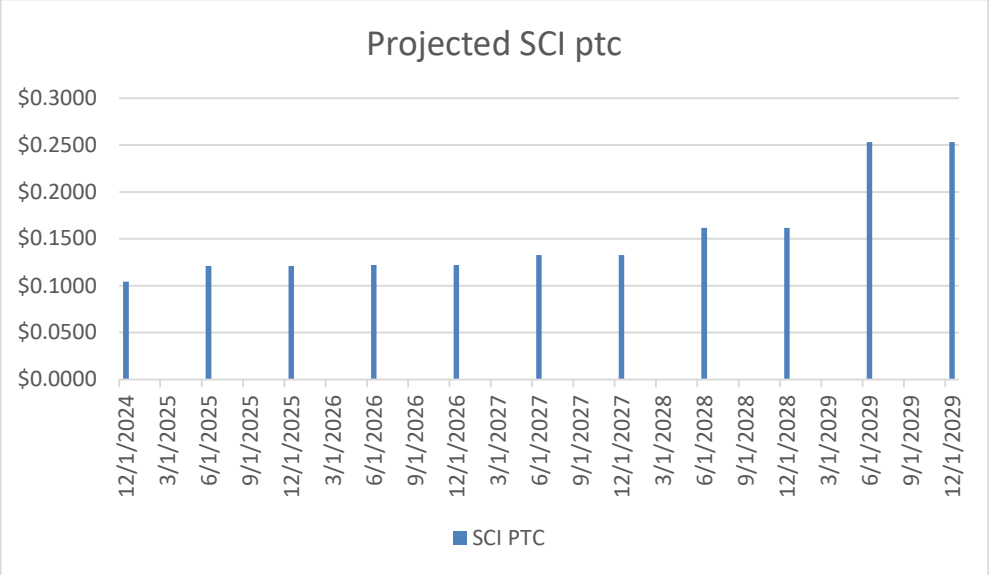
Cashout goes out 5/31/26
Reconciled 3/31/26
Half of reconciliation hits 6/1/26
Other half hits 12/1/26

Excess generation 6/1/25 - 5/31/26
Net metering expenses April 2025 - March 2026

PROJECTED:	12/1/2024	6/1/2025	12/1/2025	6/1/2026
SCI PTC	$ 0.10446	0.12114	$ 0.12114	$ 0.12209

PROJECTED:	2024	2025	20
SCI Net Metering Expense[(1)]	$ 10,350,518	$ 10,841,474	$

[(1)] Net Metering expense reflected in each SCI PTC is 1/2 of the amount filed in the March GSC-1 reconcil (ex. in June '24, the PTC included 1/2 the reconciliation amount for the GSC-1 reconciliation filed in Marc April '23-March '24)



12/1/2026	6/1/2027	12/1/2027	6/1/2028	12/1/2028	6/1/2029
$ 0.12209	$ 0.13247	$ 0.13247	$ 0.16178	$ 0.16178	$ 0.25314

26	2027	2028	20
2,109,807	$ 13,475,198	$ 47,224,384	$

iation, includes expenses from April - March of year
:h '24, which included net metering expenses from

9.35%
30%

12/1/2029
$ 0.25314

29
118,804,292

	Total
Projected 2025 kWh Bank	49,842,515
Projected 2025 kWh Bank w/ Cancellation Rate ~75%	12,460,629
Projected 2026 kWh Bank	172,008,146
Projected 2026 kWh Bank w/ Cancellation Rate ~75%	43,002,037
Projected 2027 kWh Bank	1,119,886,777
Projected 2027 kWh Bank w/ Cancellation Rate ~75%	279,971,694
Projected 2028 kWh Bank	2,663,225,657
Projected 2028 kWh Bank w/ Cancellation Rate ~75%	665,806,414
Projected 2029 kWh Bank	4,087,014,528
Projected 2029 kWh Bank w/ Cancellation Rate ~75%	1,021,753,632

Cancellation Rate	75%

17.3% Capacity Factor
49,842,515
12,460,629
69,667,956
17,416,989
441,473,228
110,368,307
1,426,007,698
356,501,925
2,937,464,726
734,366,182

cancellation rate now incorporated into kWH projection

Year of Reconciliation/Cashout:	2024	2025	2026
SCI Excess kWh for MGs (kWh Cashed Out)			17,416,989
SCI PTC In effect (5/31)	$ 0.11386	$ 0.12114	$ 0.12114
SCI Net Metering Expense from MGs			$ 2,109,807
Total Estimated SCI Net Metering Expense	$ 10,350,518	$ 10,841,474	$ 12,951,281
	^ Actual expense	*^ Actual expense*	
PTC Premium to Wholesale Supply			$ 0.03544
Annual Premium Paid by Non NM Customers			$ 617,240

NOTES:

The amount of the net metering expense that is included in the reconciliation is only through March of a given Utilizing Cashout kWh amount on 5/31 to calculate net metering expense used in 3/31 reconciliation

2027	2028	2029	2030	
110,368,307	356,501,925	734,366,182		<-- Updated 2/11/26
$ 0.12209	$ 0.13247	$ 0.16178	$ 0.25314	
$ 13,475,198	$ 47,224,384	$ 118,804,292		
$ 24,316,672	$ 58,065,858	$ 129,645,766		<--cashout amount to be reflected

$ 0.03847	$ 0.04875	$ 0.07776	<--PTC minus procurement rate
$ 4,245,501	$ 17,379,128	$ 57,107,518	

year and the cashout kWh is through May of that same year, so there is some estimation happening here wi

in reconciliation for March of each column year, based on projected kWh balance for 5/31 of each colur

th timing

mn year

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/29 & 12/1/29

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.07974	(1)
	100.00%	
$	0.07974	
	1.062699	
$	0.08474	
$	0.12316	(2)
$	0.00526	
$	0.00033	
$	0.12875	
	1.062699	
$	0.136823	
$	0.22156	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.25314	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2028 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	780,779,897
2	Energy Procurement (Schedule 2, Line 2A, Column M)	739,012,116
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	131,746,374
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	875,439,073
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(94,659,177)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (91,753,470)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (98,954,413)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2029

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	88,816,099	
654,715,616	84,296,500	
3,449,574	(22,283)	
2,100,608	129,645,766	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	214,145,429	
30,670,154	(125,329,331)	
2,472,504	433,203	
$ 33,142,658	$ (124,896,128)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (130,202,792)	
$ 15,624,190	$ (65,101,396)	
$ 15,624,190	$ (65,101,396)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/28 & 12/1/28

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.07906	(1)
	100.00%	
$	0.07906	
	1.062699	
$	0.08401	
$	0.03934	(2)
$	0.00388	
$	0.00024	
$	0.04346	
	1.062699	
$	0.046183	
$	0.13020	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.16178	

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2027 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	812,099,903
2	Energy Procurement (Schedule 2, Line 2A, Column M)	768,164,344
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	60,166,466
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	833,011,393
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	(20,911,490)
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ (18,005,783)
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ (25,206,726)

Amount Recovered in Rate 6/1
Amount Recovered in Rate 12/1

Schedule 1

)N
)NCILIATION
31, 2028

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed	
691,963,798	120,136,105	
654,715,616	113,448,728	
3,449,574	(22,283)	
2,100,608	58,065,858	<-- Linked to Net Metering Expense
1,027,846	225,446	
661,293,644	171,717,749	
30,670,154	(51,581,644)	
2,472,504	433,203	
$ 33,142,658	$ (51,148,441)	
(1,894,279)	(5,306,664)	
$ 31,248,379	$ (56,455,105)	
$ 15,624,190	$ (28,227,552)	
$ 15,624,190	$ (28,227,552)	

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/27 & 12/1/27

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.07878	(1)
	100.00%	
$	0.07878	
	1.062699	
$	0.08372	
$	0.01264	(2)
$	0.00331	
$	0.00021	
$	0.01616	
	1.062699	
$	0.017168	
$	0.10089	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.13247	

ROUNDING $ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2026 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	832,553,104
2	Energy Procurement (Schedule 2, Line 2A, Column M)	787,153,552
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	26,417,280
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	818,251,415
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	14,301,689
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 17,207,396
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 10,006,453

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2027

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	140,589,306
654,715,616	132,437,936
3,449,574	(22,283)
2,100,608	24,316,672
1,027,846	225,446
661,293,644	156,957,771
30,670,154	(16,368,465)
2,472,504	433,203
$ 33,142,658	$ (15,935,262)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (21,241,926)
$ 15,624,190	$ (10,620,963)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/26 & 12/1/26

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.07869 (1)		
	100.00%		
$	0.07869		
	1.062699		
$	0.08363		
$	0.00316 (2)		
$	0.00314	$	0.00314
$	0.00020		0.00020
$	0.00649		
	1.062699		
$	0.00690		
		ROUNDING	
$	0.09052	$	0.00001
$	0.03158 (3), (5)		
$	0.00000 (4)		
$	0.12209		

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

PPL ELECTRIC UTILITIES CORPORATIC
GENERATION SUPPLY CHARGE-1 ("GSC-1") RECC
Report for the Period April 1, 2025 through March

Line No.		(A) Total
1	Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)	843,998,190
2	Energy Procurement (Schedule 2, Line 2A, Column M)	794,324,747
	PJM Expenses (Schedule 2, Line 2B, Column M)	3,427,291
	Net Metering Expenses (Schedule 2, Line 2C, Column M)	15,051,889
	Administrative Expenses (Schedule 2, Line 2D and Line 2E, Column M)	1,253,292
	Total Expenses to Recover	814,057,219
3	Net Over/(Under) Collection (Schedule 2, Line 4, Column M)	29,940,972
4	Interest on Over/(Under) Collection (Schedule 2, Line 5, Column M)	2,905,707
5	Net Over/(Under) Collection Amount, Including Interest (Schedule 2, Line 6, Column M)	$ 32,846,679
6	Remaining E-Factor Balance (Schedule 3, Line 15, Columns B, D and F)	(7,200,943)
7	Total Over/(Under) - (Line 5 plus Line 6)	$ 25,645,736

Amount Recovered in Rate 6/1

Schedule 1

)N
)NCILIATION
31, 2026

(B) Residential Fixed	(C) Small Commercial & Industrial - Fixed
691,963,798	152,034,392
654,715,616	139,609,131
3,449,574	(22,283)
2,100,608	12,951,281
1,027,846	225,446
661,293,644	152,763,575
30,670,154	(729,182)
2,472,504	433,203
$ 33,142,658	$ (295,979)
(1,894,279)	(5,306,664)
$ 31,248,379	$ (5,602,643)
$ 15,624,190	$ (2,801,322)

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Effective 6/1/25 (ACTUAL) & 12/1/25 (ASSUMED)

1	Average Full Requirements Price
2	Times portion of Small Commerical and Industrial Load
3	Total Weighted Full Requirements Price
4	Multiplied by (1/(1-GRT)) *GRT = 5.9%*
5	Block and Full Requirements Price adjusted for GRT
6	E Factor Rate
7	Administrative Charges Rate
8	Merchant Function Charge (MFC) Rate
9	Subtotal (Line 6 + Line 7 + Line 8)
10	Multiplied by (1/(1-GRT))
11	(E Factor + Admin Charges + MFC) x GRT
12	Generation Supply Charge (Line 5 + Line 11)
13	Transmission Service Charge (TSC)
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)

Note: Data may not total due to rounding.

(1) The average Full Requirements price is adjusted for the Loss Factor and PJM deration fact compliance costs.

(2) Represents an under-collection of April 2023 through March 2024 actual revenue, which v 12 months.

(3) The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross R 5.9%.

(4) The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8: applicable refunds.

(5) TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. L customers receive a demand charge of $12.080/kW.

$	0.08064	(1)
	100.00%	
$	0.08064	
	1.062699	
$	0.08570	
$	0.00034	(2)
$	0.00311	
$	0.00019	
$	0.00364	
	1.062699	
$	0.00387	
$	0.08956	
$	0.03158	(3), (5)
$	0.00000	(4)
$	0.12114	

ROUNDING
$ 0.00001

or and includes AEPS

will be collected over

eceipts Tax (GRT) of

111-A(d) less any

.P4 transmission

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

SUR-SURREJOINDER TESTIMONY OF
ANDREW CASTANARO
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION

Topics: **Maximum Registered Peak Load**

Dated: March 6, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew Castanaro. My business address is 827 Hausman Road, Allentown, Pennsylvania 18104.

Q. By whom are you employed and in what capacity?

A. I am employed by PPL Services Corporation ("PPL Services"), an affiliate of PPL Electric Utilities Corporation ("PPL Electric" or the "Company") that provides services to PPL Electric, as the Energy Procurement Manager.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted direct testimony on behalf of the Company, PPL Electric Statement No. 15, rebuttal testimony, PPL Electric Statement No. 15-R, surrebuttal testimony, PPL Electric Statement No. 15-SR, and rejoinder testimony, PPL Electric Statement No. 15-RJ.

Q. What is the purpose of your sur-surrejoinder testimony?

A. The purpose of my rejoinder testimony is to respond to the surrejoinder testimony of Customer-Generator Coalition Witness Sharfman (CGC St. No. 1-SR) regarding the Company's Maximum Registered Peak Load ("MRPL") proposal. In my sur-surrejoinder, I focus on certain arguments of Mr. Sharfman raised in his surrejoinder testimony, and my

failure to respond to a specific argument or issue should not be interpreted as my agreement with it.

Q. Have you prepared any exhibits in support of your sur-surrejoinder testimony?

A. Yes. Attached to my testimony is:

- PPL Electric Exhibit AC-1SSRJ – An example calculation of the Rate GSC-2 rate used to determine the compensation for customer-generators with the inclusion of a capacity component, line loss, and a gross-up for Gross Receipts Tax ("GRT").

II. MAXIMUM REGISTERED PEAK LOAD

Q. Before addressing Mr. Sharfman's surrejoinder testimony, has the Company reached a Joint Stipulation and Settlement on the MRPL that alters its litigation position?

A. Yes. On March 5, 2026, the Company filed a Joint Stipulation and Settlement with the Joint Solar Advocates that modifies the Company's litigation position on the MRPL. Under that Joint Stipulation, the MRPL proposal now contains a grandfathering provision for up to 140 MW of Rate GSC-1 customer-generators and a provision that would add components to the Rate GSC-2 that is used for determining the year-end cash-out rate for Rate GSC-2 customer-generators' banked excess generation.

Q. Could you please explain what the 140 MW represents?

A. Yes. The 140 MW would cover the capacity of existing Rate GSC-1 customer-generators as of the date of the Company's rate case filing (i.e., approximately 15.5 MW) along with the amount of capacity of Rate GSC-1 customer-generators' projects that have been placed into service after the rate case filing or are in the interconnection queue and slated to be placed in service by September 30, 2026 (i.e., approximately 124.5 MW). Moreover, using the modeling in my updated analyses (see PPL Electric Exhibits AC-4RJ through AC-6RJ), the Company calculated that for every 70 MW of capacity, the excess generation from those projects places upward pressure of about $0.01 per kWh on the Rate GSC-1 Price to Compare ("PTC"). Collectively, the 140 MW would place about $0.02 per kWh of upward pressure, which helps mitigate the impact of these projects on the Rate GSC-1 PTC substantially compared to the status quo, as demonstrated in my corrected and updated analyses (see PPL Electric Exhibits AC-1RJ through AC-6RJ).

Q. Mr. Sharfman critiques your rejoinder testimony about the inclusion of a capacity component in Rate GSC-2, saying that you have not "quantif[ied] the proposed capacity component." (CGC St. No. 1-SRJ, p. 9.) Please respond.

A. Attached to my testimony as PPL Electric Exhibit AC-1SSRJ is an example of the Rate GSC-2 rate calculation for Rate GS-3 and Rate LP-4 customer-generators with the inclusion of a capacity component, line loss, and a gross-up for GRT. This example calculation was based on today's costs, and obviously the precise dollars in various components would fluctuate over time based on the actual costs. However, as you can see, the Joint Stipulation would

provide current Rate GSC-2 cash out rates for Rate GS-3 and Rate LP-4 customer-generators of $0.09601 per kWh and $0.12646 per kWh, respectively. The inclusion of the capacity component, line loss, and a gross-up for GRT adds $0.02062 per kWh and $.01897 per kWh to the GSC-2 cash out rates for GS-3 and LP-4 customer-generators, respectively. Comparatively, the Company's current rate for cash-out, the Small C&I PTC, which CGC witness Sharfman continues to advocate that these customer-generators remain under, is $0.12681 per kWh. That is a difference of $0.0308 per kWh for Rate GS-3 customer-generators and a mere $0.00035 per kWh for Rate LP-4 customer-generators. Thus, the inclusion of these components severely undercuts Mr. Sharfman's claims of financial harm to projects that would not be grandfathered under the Joint Stipulation.

Q. Mr. Sharfman alleges that you made four errors in your original analyses presented in your direct testimony. (CGC St. No. 1-SSRJ, p. 2.) Is that correct?

A. No. There were only two errors: (1) the use of a 0% cancellation rate instead of 36% in PPL Electric Exhibit AC-1; and (2) the failure to capture the excess generation from Rate LP-4 projects that would receive service under Rate GSC-1. Mr. Sharfman mischaracterizes my use of a 29.8% capacity factor and my non-inclusion of an offset to default service supply procurements as errors. In actuality, I used a different capacity factor of 17.3% and included an offset to default service supply procurements in my updated analyses (PPL Electric Exhibits AC-4RJ through AC-6RJ) in response to criticisms from other parties about my initial analyses. I still maintain that my initial analyses did not err in those respects, which is why I presented the corrected analyses in PPL Electric Exhibits AC-1RJ through AC-3RJ.

Q. Does Mr. Sharfman misstate what your rejoinder exhibits represent?

A. Yes. On page 2 of his surrejoinder, Mr. Sharfman claims that my "exhibits AC-4RJ, AC-5RJ & AC-6RJ . . . revise the values provided in [my] original exhibits AC-1RJ, AC-2RJ & AC-3RJ." That is not true. PPL Electric Exhibits AC-1RJ through AC-3RJ are my initial analyses, previously provided as PPL Electric Exhibits AC-1 through AC-3, with the corrections of the cancellation rate in the 36% cancellation rate scenario (see PPL Electric Exhibits AC-1 and AC-1RJ) and of the excess generation to capture the distribution Rate LP-4 projects under default service Rate GSC-1 (see PPL Electric Exhibits AC-1 through AC-3 and AC-1RJ through AC-3RJ). The referenced PPL Electric Exhibits AC-4RJ through AC-6RJ are the updated analyses, which take the corrected analyses set forth in PPL Electric Exhibits AC-1RJ through AC-3RJ and layer in the 17.3% capacity factor and the offset to the default service supply procurements.

Q. Mr. Sharfman attempts to criticize the analyses in your rejoinder testimony by comparing "PPL's 2027 and 2028 PTC projects under the 36% cancelation scenario to 2027 and 2028 PPL zone forward prices." (CGC St. No. 1, pp. 3-4; CGC Exhibit 1-SRJ.) Is that an appropriate or reliable comparison?

A. No. To be clear, it is Mr. Sharfman's position that these no-load customer generators should continue to be compensated for excess generation at the Small C&I PTC. Under the Company's proposal as modified by the Joint Stipulation and Settlement, Rate GSC-1 no-load customer-generators who are not otherwise grandfathered would be moved to the Large

C&I default service customer class (i.e., Rate GSC-2) and compensated under rate calculated by the Company to reflect the Large C&I PTC. In his analysis, Mr. Sharfman fails to recognize that the PTC is not equivalent to wholesale energy prices. The reason why is that the cost of procuring wholesale supply under the Company's default service supply contracts is only one component of the PTC. The PTC includes an E-Factor, which reconciles for over- and under-recoveries in the PTC every six months. That is critical because the costs associated with net metering compensation are recovered through the PTC's E-Factor. The projected wholesale energy prices referenced by Mr. Sharfman do not include any costs for net metering compensation. The whole point of my analyses is to account for those costs. Moreover, the PTC includes other components that are not reflected in wholesale energy prices, such as administrative charges, Alternative Energy Credits ("AECs"), capacity costs, taxes, and the Transmission Service Charge ("TSC"). Therefore, Mr. Sharfman's comparison has no merit and should be disregarded.

Q. Mr. Sharfman also compares the Company's projected Rate GSC-1 PTC rates to U.S. Energy Information Association's ("EIA") projected generation prices and asserts that "there is no indication from the wholesale market that 2029 PTCs would run anywhere near $0.30 per kWh or $300 per MWh." (CGC St. No. 1-SRJ, p. 6; CGC Exhibit 3-SRJ.) Is that an appropriate or reliable

A. No. Again, Mr. Sharfman repeats his error by improperly conflating the PTC with projected wholesale energy prices and failing to account for any rate increases due to net metering expenses. He also compounds this error because the referenced EIA data: (1) pertains to the

PJM East region, which is not specific to PPL Electric's service territory and includes New Jersey, Delaware, and portions of Maryland; and (2) is an average of residential, commercial, and industrial rates. Yet, Mr. Sharfman compares that data to the projected PTC rates for Rate GSC-1, which consists of Rate GS-3 (small commercial) and Rate LP-4 (large commercial) default service customers under 100 kW. Thus, this comparison also has no merit and should be rejected. I would also note that CGC's position is that its members should not be exposed to the wholesale market and require the price certainty of the Small C&I PTC, which does not directly track the wholesale market. Mr. Sharfman's reliance on wholesale market futures in analyzing future PTC rates completely undermines CGC's core argument.

Q. Mr. Sharfman asserts that the projected increases in the Rate GSC-1 PTC "won't harm customers" because those customers could switch to an EGS instead. (CGC St. No. 1-SRJ, p. 6.) Do you agree?

A. No. Mr. Sharfman's position is severely flawed. First, an increase in shopping customers would leave fewer default service customers paying the PTC, meaning that there would be fewer customers over which to spread default service costs, which would drive up the PTC even more than is shown in my analyses. Given that Mr. Sharfman essentially concedes that a switching risk exists, when he states that "[i]f PPL were to charge $1.32804 per kWh PTC to GSC-1 customers . . . there would be mass exodus of PPL customers to EGS service," Mr. Sharfman's proposed solution would simply leave a small amount of non-customer-generators who do not shop left holding the bag for an enormous amount of net metering compensation costs, taking the PTC rate to unprecedented heights and further increasing the

profits of these no-load customer-generators. Although that may be good news for the CGC membership on whose behalf Mr. Sharfman is testifying, that is catastrophic news to small businesses that are trying to make ends meet and afford their electric bills.

Second, Mr. Sharfman appears to hinge his position on a fallacy that EGSs do not benchmark their rate offerings against the PTC. I previously provided testimony that there are industry studies that demonstrate that suppliers set price offerings off of the utilities' PTCs, not the wholesale market. (*See* PPL Electric St. No. 15-SR, p. 3). In fact, I am advised by counsel that suppliers in Pennsylvania have argued that additional costs should be allocated from distribution rates to default service to help drive up the PTC and make their rate offerings more competitive with the PTC. *See NRG Energy, Inc. v. Pa. PUC*, 233 A.3d 936 (Pa. Cmwlth. 2020).

Third, Mr. Sharfman appears to base his position on the relative difference between the lowest offers on papowerswitch.com for PPL Electric's service territory and the PTC. According to Mr. Sharfman:

> The lowest offer in PPL's service territory is 24% lower than the PPL PTC. There would be a much tighter spread if EGS' simply moved their prices to match the PTC price level.

(CGC St. No. 1-SRJ, p. 5.) Mr. Sharfman is cherry-picking the single lowest offer of $0.09790 per kWh out of the total of 103 offers he analyzed to derive that "spread." He also does not comment on what the offer's other terms were that could have affected the price offered, such as a short-term contract or a teaser rate that would increase after an initial term. Mr. Sharfman also presents no analysis about the spread of all these offers relative to the PTC, nor does he account for: (1) any timing differences between when he pulled these prices on

January 28, 2026, and when the current PTC went into effect on December 1, 2025; or (2) how EGSs may be pricing their products in advance of the next PTC effective June 1, 2026.

For these reasons, Mr. Sharfman's arguments and positions continue to be critically flawed and should be rejected. If anything, his surrejoinder appears to confirm that CGC wants to create a scenario where non-customer-generators under Rate GSC-1 must flee default service to escape increased rates caused by no-load customer-generators, which will only serve to drive up the PTC rate even further and substantially increase small businesses' electric bills, while providing a financial windfall for no-load customer-generators.

III. CONCLUSION

Q. Does this conclude your sur-surrejoinder testimony?

A. Yes, it does.

PPL Electric Utilities Corporation
Estimated LCI Net Metering Cashout Rate Calculation
For Illustrative Purposes Only
Large Commercial & Industrial ("LC&I") - Secondary - Rate GS-3 >= 100 kW
Based on PJM LMPs from 6/1/2025 through 11/30/2025
Used for cashout 12/1/25-5/30/26

Generation			
1	kWh_t	1	
2	Loss Factor [1]	1.05365	
3	LMP_t -- Real-time PJM Locational Marginal Price for the PPL Zone for each hour Average of the daily LMP over the previous 6 months (Dec - May for the June calculation & Jun - Nov for the December calculation)	0.03730	$/kWh
4	HP adder -- Supplier's portion of the GSC-2 Administrative Charge per kWh (tariff page 19Z.6)	0.01005	$/kWh
5	Capacity - Portion of LCI obligation per kWh [2]	0.01373	$/kWh
6	E Factor reconciliation component (tariff page 19Z.7, first paragraph) [3]	-0.00370	$/kWh
7	Administrative Charges -- PPL Electric Utilities' portion of the GSC-2 Administrative Charge per	0.00016	$/kWh
8	EGS Supply Risk Factor (Line 4 + Line 5 + Line 6 + Line 7)	0.02025	$/kWh
9	$\sum_t$ HP Energy Charge [Line 1 x Line 2 x (Line 3 + Line 8)]	0.06063	$/kWh
10	Multiplied by (1/(1-GRT)) *GRT = 5.9%*	1.0627	
11	Hourly Pricing Energy Charge (Line 9 x Line 10)	0.06443	$/kWh
Transmission			
12	Transmission Service Charge (TSC) -- kWh [4]	0.03158	$/kWh
13	Transmission Service Charge (TSC) -- Demand [5]	0.000	
14	Subtotal (Line 11 + Line 12 + Line 13)	0.09601	$/kWh
15	State Tax Adjustment Surcharge (STAS) rate [6]	0.00001	
16	Total (Line 14 x (1 + Line 15))	0.09601	$/kWh
17	**Excess Net Metering Cashout Rate (Line 17)**	**0.09601**	**$/kWh**

[1] The Loss Factor is adjusted for the PJM transmission deration factor.
[2] Capacity price multiplied by the annual LCI POLR contribution to peak divided by annual LCI kWh
[3] Represents the over-collection from April 1, 2024 through March 31, 2025, that will be refunded from June 1, 2025 through May 31, 2026.
[4] The TSC kWh charge is calculated by multiplying the customer's kWh usage times the stated rate. The rate includes the statutory PA Gross Receipts Tax (GRT) of 5.9%.
[5] The TSC demand charge is calculated by multiplying the customer's billing kW times the stated rate. The rate includes the statutory GRT of 5.9%.
[6] The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.

Business Use

PPL Electric Utilities Corporation
Estimated LCI Net Metering Cashout Rate Calculation
For Illustrative Purposes Only
Large Commercial & Industrial ("LC&I") - Primary - Rate LP-4 >= 100 kW
Based on PJM LMPs from 6/1/2025 through 11/30/2025

1	kWh_t	1	
2	Loss Factor [1]	1.02682	
3	LMP_t -- Real-time PJM Locational Marginal Price for the PPL Zone for each hour Average of the daily LMP over the previous 6 months (Dec - May for the June calculation & Jun - Nov for the December calculation)	0.03730	$/kWh
4	HP adder -- Supplier's portion of the GSC-2 Administrative Charge per kWh (tariff page 19Z.6)	0.01005	$/kWh
5	Capacity - Portion of LCI obligation per kWh [2]	0.01373	$/kWh
6	E Factor reconciliation component (tariff page 19Z.7, first paragraph) [3]	-0.00370	$/kWh
7	Administrative Charges -- PPL Electric Utilities' portion of the GSC-2 Administrative Charge per KWH (tariff page 19Z.6)	0.00016	$/kWh
8	EGS Supply Risk Factor (Line 4 + Line 5 + Line 6 + Line 7)	0.02024	$/kWh
9	$\sum_t$ HP Energy Charge [Line 1 x Line 2 x (Line 3 + Line 8)]	0.05908	$/kWh
10	Multiplied by (1/(1-GRT)) *GRT = 5.9%*	1.0627	
11	Hourly Pricing Energy Charge (Line 9 x Line 10)	0.06278	$/kWh
	Transmission		
12	Transmission Service Charge (TSC) -- kWh [4]	0.000	
13	Transmission Service Charge (TSC) -- Demand [5]		
	kW Charge	21.35	$
	kW Estimate	298,874	kW
	kWh Estimate	100,207,675	kWh
	kWh rate	0.06368	$/kWh
14	Subtotal (Line 11 + Line 12 + Line 13)	0.12646	$/kWh
15	State Tax Adjustment Surcharge (STAS) rate [6]	0.00001	
16	Total (Line 14 x (1 + Line 15))	0.12646	$/kWh
17	**Excess Net Metering Cashout Rate (Line 17)**	**0.12646**	**$/kWh**

[1] The Loss Factor is adjusted for the PJM transmission deration factor.

[2] Capacity price multiplied by the annual LCI POLR contribution to peak divided by annual LCI kWh

[3] Represents the over-collection from April 1, 2024 through March 31, 2025, that will be refunded from June 1, 2025 through May 31, 2026.

[4] The TSC kWh charge is calculated by multiplying the customer's kWh usage times the stated rate. The rate includes the statutory PA Gross Receipts Tax (GRT) of 5.9%.

[5] The TSC demand charge is calculated by multiplying the customer's billing kW times the stated rate. The rate includes the statutory GRT of 5.9%.

[6] The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.

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CHAPTER 54. ELECTRICITY GENERATION CUSTOMER CHOICE

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A.	CUSTOMER INFORMATION	54.1
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D.	ADJUSTMENT OF ELECTRIC DISTRIBUTION COMPANY RATES FOR CHANGES IN STATE TAX LIABILITY	54.91
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Cross References

This chapter is cited in 52 Pa. Code § 69.1802 (relating to purpose); 52 Pa. Code § 75.67 (relating to alternative energy cost-recovery); 52 Pa. Code § 111.5 (relating to agent training); 52 Pa. Code § 111.9 (relating to door-to-door sales); and 52 Pa. Code § 111.10 (relating to telemarketing).

Subchapter A. CUSTOMER INFORMATION

Sec.
54.1. Purpose.
54.2. Definitions.
54.3. Standards and pricing practices for retail electricity service.
54.4. Bill format for residential and small business customers.
54.5. Disclosure statement for residential and small business customers.
54.6. Request for information about generation supply.
54.7. Marketing/sales activities.
54.8. Privacy of customer information.
54.9. Complaint handling process.
54.10. Notice of contract expiration or change in terms for residential and small business customers.

Authority

The provisions of this Subchapter A issued under the Public Utility Code, 66 Pa.C.S. §§ 501, 504—506, 1301 and 1501; and the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. § 2807, unless otherwise noted.

Source

The provisions of this Subchapter A adopted August 7, 1998, effective August 8, 1998, 28 Pa.B. 3780, unless otherwise noted.

§ 54.1. Purpose.

(a) The purpose of this subchapter is to require that electricity providers enable customers to make informed choices regarding the purchase of electricity services offered by providing adequate and accurate customer information. Information shall be provided to customers in an understandable format that enables customers to compare prices and services on a uniform basis.

(b) As to the scope of this subchapter, this section and §§ 54.2—54.3 apply to all customers, including large commercial and industrial customers. Sections 54.4—54.9 apply only to residential and small business customers, as the term is defined in § 54.2 (relating to definitions).

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§ 54.2. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

Aggregator or *market aggregator*—An entity, licensed by the Commission, that purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers.

Basic services—Services necessary for the physical delivery of electricity service, including generation, transmission and distribution. Transition charges, although temporary in scope, are basic service charges (See the definition of transition charges in this section).

Broker or *marketer*—An entity, licensed by the Commission, that acts as an agent or intermediary in the sale and purchase of electric energy but does not take title to electric energy.

CTC—Competitive Transition Charge—A nonbypassable charge applied to the bill of every customer accessing the transmission or distribution network which (charge) is designed to recover an electric utility's transition or stranded costs as determined by the Commission in sections 2804 and 2808 of the code (relating to standards for restructuring of electric industry; and competitive transition charge).

Code—The Public Utility Code, 66 Pa.C.S. §§ 101—3316.

Consumer—A retail electric customer or potential customer of retail electricity service.

Consumer contract—The written disclosure statement of the terms of service between a customer and an EGS which satisfies the definition of consumer contract in section 3 of the Plain Language Consumer Contract Act (73 P. S. § 2203).

Customer—A retail electric customer.

Customer information—Written, oral or electronic communications used by electricity providers to communicate to consumers prices and terms of service.

Distribution charges—Basic service charges for delivering electricity over a distribution system to the home or business from the transmission system. These charges include basic service under § 56.15(4) (relating to billing information) and universal service, as applicable.

EDC—Electric Distribution Company—The public utility providing facilities for the jurisdictional transmission and distribution of electricity to retail customers, except building or facility owners or operators that manage the internal distribution system serving the building or facility and that supply electric power and other related electric power services to occupants of the building or facility.

EGS—Electric Generation Supplier or *Supplier*—

(i) A person or corporation, including a municipal corporation, which provides service outside its municipal limits except to the extent provided

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prior to the effective date of this chapter. (*Editor's Note*: The reference to ''this chapter'' refers to the code.) This includes brokers and marketers, aggregators or other entities that sell to end-use customers electricity or related services utilizing the jurisdictional transmission or distribution facilities of an electric distribution company.

(ii) The term excludes building or facility owner/operators that manage the internal distribution system for the building or facility and that supply electric power and other related power services to occupants of the building or facility.

(iii) The term also excludes electric cooperative corporations except as provided in 15 Pa.C.S. Chapter 74 (relating to generation choice for customers of electric cooperatives).

Electricity providers—The term refers collectively to the EDC, EGS, electricity supplier, marketer, aggregator or broker, as well as any third party acting on behalf of these entities.

Generation charges—Basic service charges for generation supply to retail customers. This excludes charges for transmission or other charges related to electric service.

Historical billing data—The minimum of 13 months of data as recorded by the EDC, which contains dollar amount billed. This data is kWh consumption on-peak and off-peak or at some other prescribed interval of consumption and associated cost and, if applicable, at demand levels at the intervals recorded and associated costs of those demand levels.

ITC—Intangible Transition Charge—Charges authorized by the Commission to be imposed on all customer bills and collected, through a nonbypassable mechanism by the electric utility or its successor or by any other entity which provides electric service to a person that was a customer of an electric utility located within the certificated territory of the electric utility on January 1, 1997, or that, after January 1, 1997, became a customer of electric services within the territory and is still located within the territory, to recover qualified transition expenses pursuant to a qualified rate order, in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the Commission in the electric utility's most recent base rate proceeding.

Marketer or *Broker*—An entity, licensed by the Commission, that acts as an agent or intermediary in the sale and purchase of electric energy and does not take title to the electric energy.

Nonbasic services—Optional recurring services which are distinctly separate and clearly not required for the physical delivery of electric service.

Renewable resource—The term includes technologies such as solar photovoltaic energy, solar thermal energy, wind power, low-head hydropower, geothermal energy, landfill or other biomass-based methane gas, mine-based methane gas, energy from waste and sustainable biomass energy.

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Small business customer—The term refers to a person, sole proprietorship, partnership, corporation, association or other business entity that receives electric service under a small commercial, small industrial or small business rate classification, and whose maximum registered peak load was less than 25 kW within the last 12 months.

Transition charges—Basic service charges for costs defined as transition or stranded costs, comprised of a CTC and an ITC, designed to recover an EDC's transition or stranded costs as authorized by the Commission.

Transition or stranded costs—An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the Commission determines will remain following mitigation by the electric utility. The term includes those items enumerated in the definition of ''transition or stranded costs,'' in section 2803 of the code (relating to definitions).

Transmission charges—Basic service charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system of an EDC.

Cross References

This section cited in 52 Pa. Code § 54.1 (relating to purpose); and 52 Pa. Code § 54.3 (relating to standards and pricing practices for retail electricity service).

§ 54.3. Standards and pricing practices for retail electricity service.

In furnishing retail electricity service, EDCs and EGSs or any entity that otherwise provides retail electricity service information to customers, shall comply with the following:

(1) Use common and consistent terminology in customer communications, including marketing, billing and disclosure statements.

(i) Use the term EDC as described in § 54.2 (relating to definitions) as a standard term.

(ii) Use the terms in accordance with the glossary posted at www.PaPowerswitch.com or other successor media platform as determined by the Commission.

(2) For residential and small commercial customers, contracts for retail electric service entered into after September 30, 2020, may not include any fees to be paid by the retail electric customer for terminating a fixed duration contract between the date the options notice required in § 54.10(2) (relating to notice of contract expiration or change in terms for residential and small business customers) is issued and the expiration of the fixed duration contract.

Source

The provisions of this § 54.3 amended July 31, 2020, effective in 60 days, 50 Pa.B. 3861. Immediately preceding text appears at serial page (247124).

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Cross References

This section cited in 52 Pa. Code § 54.1 (relating to purpose).

§ 54.4. Bill format for residential and small business customers.

(a) EGS prices billed must reflect the marketed prices and the agreed upon prices in the disclosure statement.

(b) The following requirements apply only to the extent to which an entity has responsibility for billing customers, to the extent that the charges are applicable. The default service provider will be considered to be an EGS for the purposes of this section. Duplication of billing for the same or identical charges by both the EDC and EGS is not permitted.

(1) EDC charges must appear separately from EGS charges.

(2) Charges for basic services must appear before charges for nonbasic services, and appear distinctly separate.

(3) Customer bills must contain the following charges, if these charges are applicable, and these charges must appear in a distinct section of the bill. The designation or label of each charge as either a basic charge or nonbasic charge appears in parenthesis following the name of the charge. This label of either basic or nonbasic is not required to accompany the name of the charge on the bill.

(i) Generation charges (basic).

(A) Generation charges shall be presented in a standard pricing unit for electricity in actual dollars or cents per kWh, actual average dollars or cents per kWh, kW or other Commission-approved standard pricing unit.

(B) Generation charges shall appear first among the basic charges with one exception. EDCs may place the customer charge first among the basic charges.

(ii) Transmission charges (basic).

(iii) Distribution charges (basic).

(iv) Customer charge or basic charge (charge for basic service in § 56.15 (relating to billing information)) (basic).

(v) Advanced metering charges (basic).

(vi) Transition charges (basic).

(vii) Taxes (comply with § 56.15) (basic).

(viii) Late payment charges (basic).

(ix) Security deposit (basic).

(x) Reconnection fee (basic).

(xi) Itemization of nonbasic charges (nonbasic).

(xii) Overall billing total.

(4) The entity reading the meter for billing purposes shall provide the following electricity use data figures:

(i) The total annual electricity use for the past 12 months in kWh, including the current billing cycle. This is a single cumulative number.

(ii) The average monthly electricity use for the past 12 months in kWh, including the current billing cycle. This is a single cumulative number.

(5) The requirements of § 56.15 shall be incorporated in customer bills to the extent that they apply.

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(6) Definitions for the following charges and terms are required in a customer's bill, if they appear as billing items, as contained in ''Common Electric Competition Terms'' and shall be in a distinctly separate section of the bill:

(i) Generation charges.

(ii) Transmission charges.

(iii) Distribution charges.

(iv) Customer charge/basic charge (charge for basic service in § 56.15).

(v) Advanced metering, if applicable.

(vi) Transition charges.

(7) ''General Information'' is the required title for customer contact information in a customer's bill.

(i) The name, address and telephone number for the EGS and EDC shall be included.

(ii) Both EDC and EGS information in subparagraph (i) is required on all customer bills with the billing entity's information first.

(8) When a customer chooses the option to receive a separate bill for generation supply, the EDC shall include in a customer's bill the following information where the EGS charges would normally appear:

(i) The EGS's name.

(ii) A statement that the customer's EGS is responsible for the billing of EGS charges.

(9) When a customer chooses the option to receive a single bill from the EDC, the EDC shall include in the customer's bill the name of the EGS where the EGS charges appear.

(10) For customers who have chosen electric generation services from a competitive supplier, the customer's bill shall include the following statements which may appear together in a paragraph:

(i) ''Generation prices and charges are set by the electric generation supplier you have chosen.''

(ii) ''The Public Utility Commission regulates distribution prices and services.''

(iii) ''The Federal Energy Regulatory Commission regulates transmission prices and services.''

(c) The billing entity shall provide samples of customer bills to the Commission for review.

Source

The provisions of this § 54.4 amended September 14, 2007, effective September 15, 2007, 37 Pa.B. 4996. Immediately preceding text appears at serial pages (247125) to (247126).

Cross References

This section cited in 52 Pa. Code § 54.1 (relating to purpose); 52 Pa. Code § 56.15 (relating to billing information); and 52 Pa. Code § 56.265 (relating to billing information).

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§ 54.5. Disclosure statement for residential and small business customers.

(a) The agreed upon prices in the disclosure statement must reflect the marketed prices and the billed prices.

(b) The EGS shall provide the customer written disclosure of the terms of service at no charge whenever:

(1) The customer requests that an EGS initiate service.

(2) The EGS proposes to change the terms of service.

(3) Service commences from a default service provider.

(c) The contract's terms of service shall be disclosed, including the following terms and conditions, if applicable:

(1) Disclosure of generation charges must conform to the following requirements:

(i) If the customer will be billed under a price per kilowatt-hour price structure, generation charges must be disclosed according to the actual prices per kilowatt-hour.

(ii) If a customer will not be billed under a price per kilowatt-hour price structure, the contract's terms must clearly explain the pricing structure and what the customer's price for generation charges will be for a given period of time.

(iii) Generation charges must include an estimate of all applicable taxes except for State sales tax and county tax.

(2) If the price is introductory, the pricing statement must include a statement that the price is an introductory price, the duration of the introductory period and the price for the first billing cycle after the introductory period.

(3) If the price is variable, the variable pricing statement must include:

(i) Conditions of variability (state on what basis prices will vary) including the factors that the EGS will rely upon to establish the variable price.

(ii) Limits on price variability:

(A) If there is a limit on price variability, such as a specific price cap, a maximum percentage increase in price between billing cycles or minimum/maximum charges per kilowatt-hour for electricity during the duration of the contract, the EGS shall clearly explain the applicable limits. The EGS shall also state that the price can change each billing period, which must be printed in font size larger than the font size appearing in the terms of service.

(B) If there is not a limit on price variability, the EGS shall clearly and conspicuously state that there is not a limit on how much the price may change from one billing cycle to the next. The EGS shall also state that the price can change each billing period, which must be printed in font size larger than the font size appearing in the terms of service.

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(iii) The price to be charged, per kilowatt-hour, for the first billing cycle of generation service.

(iv) A description of when and how the customer will receive notification of price changes. If the customer will not know the price until the time of billing, this must be disclosed in font size larger than the font size appearing in the terms of service.

(4) If the unit price changes based on actual customer usage or if the offer includes fees in addition to the unit price, the price per kWh must factor in all costs associated with the rate charged to the customer, including any fees, and show the average price per kWh for usages of 500, 1,000 and 2,000 kWh of electricity in a table format. If the offer includes an introductory price, the disclosure statement must show the average price per kWh of the introductory price, including any fees, and the price offered after the introductory period, including any fees, in separate tables.

(i) If the price is a fixed monthly amount, including any fees, that does not change based on actual customer usage, the disclosure statement must show the average price per kWh for usages of 500, 1,000 and 2,000 kWh of electricity in a table format.

(ii) If the price varies based on when the customer actually uses electricity, such as a time-of-use offer, the disclosure statement must show the price per kWh for each time period in table format.

(5) An itemization of basic and nonbasic charges distinctly separate and clearly labeled.

(6) The duration of the agreement, which includes:

(i) The starting date.

(ii) The expiration date, if applicable.

(7) An explanation of sign-up bonuses, add-ons, limited time offers, other sales promotions and exclusions, if applicable.

(8) An explanation of prices, terms and conditions for special services, including advanced metering deployment, if applicable.

(9) The cancellation provisions, if applicable.

(10) The renewal provisions, if applicable.

(11) An explanation of limits on price variability, penalties, fees or exceptions, printed in font size larger than the font size appearing in the terms of service, but not less than 12-point font. Penalties and fees must be disclosed in actual dollars or a specific method for determining the actual dollars must be disclosed. This explanation must include a statement advising the customer that the customer will not be subject to a penalty or fee if the customer terminates the contract at any time between the date the options notice required under § 54.10(2) (relating to notice of contract expiration or change in terms for residential and small business customers) is issued and the expiration of the fixed duration contract.

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(12) Customer contact information that includes the name of the EGS, the EGS's address, telephone number, Commission license number and Internet address, if available.

(13) A statement providing that information about shopping for an electric supplier is available at www.PaPowerSwitch.com or other successor media platform as determined by the Commission, by calling the Commission at (800) 692-7380 and the Office of Consumer Advocate at (800) 684-6560 or at www.oca.state.pa.us.

(14) For contracts with variable pricing, the EGS shall provide:

(i) A telephone number and Internet address at which a customer may obtain the previous 24 months' average monthly billed prices for that customer's rate class and EDC service territory. If an EGS has not been providing generation service in a rate class and EDC service territory for 24 months, the EGS shall provide the average monthly billed prices for the months available to date. If price history or representative price information is not available and the offer is materially different from other offers made by the EGS, the EGS shall inform the customer of this fact.

(ii) In plain language, a statement that historical pricing is not indicative of present or future pricing.

(d) Customers shall be provided a 3-day right of rescission period following receipt of the disclosure statement.

(1) The 3-day right of rescission is 3 business days.

(2) The 3-day right of rescission begins when the customer receives the written disclosure.

(3) The customer may cancel in writing, orally or electronically, if available.

(4) Waivers of the 3-day right of rescission are not permitted.

(e) Definitions for generation charges and transmission charges, if applicable, are required on electric disclosure statements and must be defined in accordance with the glossary posted at www.PaPowerSwitch.com or other successor media platform as determined by the Commission. Definitions for each of the basic and nonbasic services, if applicable, are required. The definition section of the disclosure statement must be distinctly separate.

(f) The EGS shall include in the customer's disclosure statement the following statements which may appear together in a paragraph:

(1) "Generation prices and charges are set by the electric generation supplier you have chosen."

(2) "The Public Utility Commission regulates distribution prices and services."

(3) "The Federal Energy Regulatory Commission regulates transmission prices and services."

(g) Disclosure statements must include the following customer notifications for fixed duration or non-fixed duration contracts:

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(1) For fixed-duration contracts, disclosure statements must include the following notification: ''If you have a fixed duration contract that will be ending, or whenever <EGS name> wants to change the contract, you will receive two separate notices before the contract ends or the changes happen. You will receive the first notice 45 to 60 days before, and the second notice 30 days before the expiration date or the date the change becomes effective. These notices will explain your options.''

(2) For contracts that are not fixed-duration contracts, disclosure statements must include the following notification: ''If <EGS name> wants to change the contract, you will receive two separate notices before the changes happen. You will receive the first notice 45 to 60 days before the change, and the second notice 30 days before the change. These notices will explain your options.''

(h) If the default service provider changes, the new default service provider shall notify customers of that change, and provide customers with its name, address, telephone number and Internet address, if available.

(i) The EGS shall provide, with the disclosure statement, a separate EGS contract summary in a format provided by the Commission.

(j) If the contract is assignable, the EGS shall inform the customer at the time the parties enter into the contract. Prior to a contract assignment, the EGS shall provide notice to the affected customer, the affected EDC and the Commission. The customer notice must include the name of the new EGS, the contact information for the new EGS, the estimated month and year that the assignment is expected to occur, and language informing the customer that contract terms and conditions remain unchanged.

(k) If the EGS intends on obtaining customer account information from the EDC, the EGS shall inform the customer of the specific type of information that may be obtained, such as usage data, the purpose for obtaining this information and that the customer is consenting to the EDC releasing this information by entering into this contract. The EGS shall also inform the customer that the EGS will maintain the confidentiality of a customer's personal information including the customer's name, address, telephone number, electric usage and historic payment information, as required by applicable Commission regulations and Federal and State laws.

Source

The provisions of this § 54.5 amended September 14, 2007, effective September 15, 2007, 37 Pa.B. 4996; amended June 13, 2014, effective June 14, 2014, 44 Pa.B. 3522; amended July 31, 2020, effective in 60 days, 50 Pa.B. 3861. Immediately preceding text appears at serial pages (372469) to (372471).

Cross References

This section cited in 52 Pa. Code § 54.1 (relating to purpose); 52 Pa. Code § 54.10 (relating to notice of contract expiration or change in terms for residential and small business customers); 52 Pa. Code § 57.173 (relating to customer contacts the EGS to request a change in electric supply service); 52 Pa. Code § 75.13 (relating to general provisions); 52 Pa. Code § 111.2 (relating to definitions); 52 Pa. Code § 111.7 (relating to customer authorization to transfer account; transaction; verification; documentation); 52 Pa. Code § 111.11 (relating to receipt of disclosure statement and right to rescind transaction); and 52 Pa. Code § 111.12 (relating to consumer protection).

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§ 54.6. Request for information about generation supply.

(a) EGSs shall respond to reasonable requests made by consumers for information concerning generation energy sources.

(1) EGSs shall respond by informing consumers that this information is included in the annual licensing report and that this report exists at the Commission. Providers shall explain that the report is available to them and offer to provide it, if requested.

(2) The default service provider shall file at the Commission the annual licensing report as required by the Commission's licensing regulations in this chapter and shall otherwise comply with paragraph (1).

(3) EGSs operating for less than 1 year may respond to customer inquiries about generation energy sources by furnishing the information as described in subsection (b).

(b) Verification of the anticipated generation energy source, of the identifiable resources (if and when they have been ''claimed'') and the fact that energy characteristics were not sold more than once, shall be conducted by an independent auditor at the end of each calendar year and contained in the annual report to the Commission, relating to information disclosure requirements in subsection (a) and the licensing regulations in this chapter.

(c) Whenever EGSs market their generation as having special characteristics, such as ''produced in Pennsylvania'' or ''environmentally friendly'' and the like, providers shall have information available to substantiate their claims.

(1) Disclosure of generation energy sources shall be identifiable, which is defined as electricity transactions which are traceable to specific generation sources by any auditable contract trail or equivalent, such as a tradable commodity system, that provides verification that the electricity source claimed has been sold only once to a retail customer. If generation energy sources are not identifiable, the provider shall disclose this fact.

(d) Electricity providers, whether they make distinguishing claims or not, shall include in their general communications with consumers that electricity is the product of a mix of generation energy sources, that is delivered over a system of wires.

(e) Electricity providers shall respond to reasonable consumer requests for energy efficiency information, by indicating that these materials are available upon request from the Commission or the EDC.

(f) The use of general, unsubstantiated and unqualified claims of environmental benefits, such as ''green'' and ''environmentally friendly,'' is prohibited. The Commission supports the application of the Federal Trade Commission's (FTC) Guides for the Use of Environmental Marketing Claims (see 16 CFR 260.1—260.8 (relating to guides for the use of environmental marketing claims)), in the enforcement of this section and the following specific principles:

(1) Section 260.6(a) (relating to general principles) which states that qualifications or disclosure should be clear, prominent, and of relative type size and

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proximity to the claim being qualified. In addition, contrary assertions which undercut the qualifications should not appear.

(2) Section 260.6(c) which states that environmental claims should not overstate the environmental attribute or benefit, expressly or by implication.

(3) Section 260.6(d) which suggests that marketing materials which make comparative claims should clearly state the basis for the comparison, be able to be substantiated, and be accurate at the time they are made.

(4) Section 260.7(a) (relating to environmental marketing claims) which labels unqualified claims of environmental benefit as deceptive.

(5) Section 260.7(f) which addresses claims regarding source reduction, such as reduced toxicity or reductions of other environmentally negative effects.

(g) Residential and small business customers are entitled to receive at no charge and at least once a year, historical billing data from whomever reads the meter for billing purposes.

(1) The EDC is only obligated to provide information that is readily available in its billing system.

(2) The historical billing data shall be conveyed in terms of kWh, and kW, as applicable, and associated charges for the current billing period and for the year preceding the current billing period.

(3) The historical billing data will be updated with each billing cycle.

(h) Electricity providers shall notify consumers either in advertising materials, disclosure statements or bills that information on generation energy sources, energy efficiency, environmental impacts or historical billing data is available upon request.

Source

The provisions of this § 54.6 amended September 14, 2007, effective September 15, 2007, 37 Pa.B. 4996. Immediately preceding text appears at serial pages (324546) and (247129) to (247130).

Cross References

This section cited in 52 Pa. Code § 54.1 (relating to purpose).

§ 54.7. Marketing/sales activities.

(a) Advertised prices must reflect prices in disclosure statements and billed prices.

(b) If the unit price changes based on actual customer usage or if the offer includes fees in addition to unit prices, written or electronic marketing materials that offer terms of service for acceptance by consumers and authorizes enrollment must factor in all costs associated with the rate charged, including any fees, and show the average price per kWh for usages of 500, 1,000 and 2,000 kWh of electricity in a table format. If the offer includes an introductory price, the EGS shall

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show the average price per kWh of the introductory price, including any fees, and the price offered after the introductory period, including any fees, in separate tables.

(1) If the price is a fixed monthly amount, including any fees, that does not change based on actual customer usage, the EGS shall show the average price per kWh for usages of 500, 1,000 and 2,000 kWh of electricity in a table format.

(2) If the price varies based on when the customer uses electricity, such as a time-of-use offer, the EGS shall show the price per kWh for each time period in a table format.

(3) The EGS shall note the effective date of the prices shown in the table provided under paragraph (1) or (2).

(c) Advertising materials targeted for residential and small business sales shall be made available upon request of the Commission in the event of a formal or informal complaint or investigation.

Source

The provisions of this § 54.7 amended July 31, 2020, effective in 60 days, 50 Pa.B. 3861. Immediately preceding text appears at serial page (372473).

Cross References

This section cited in 52 Pa. Code § 54.1 (relating to purpose).

§ 54.8. Privacy of customer information.

(a) An EDC or EGS may not release private customer information to a third party unless the customer has been notified of the intent and has been given a convenient method of notifying the entity of the customer's desire to restrict the release of the private information. Specifically, a customer may restrict the release of either the following:

(1) The customer's telephone number.

(2) The customer's historical billing data.

(b) Customers shall be permitted to restrict information as specified in subsection (a) by returning a signed form, orally or electronically.

(c) Nothing in this section prohibits the EGS and EDC from performing their mandatory obligations to provide electricity service as specified in the disclosure statement and in the code.

Cross References

This section cited in 52 Pa. Code § 54.1 (relating to purpose).

§ 54.9. Complaint handling process.

EDCs and EGSs shall disclose to consumers the following with respect to the rights of consumers in the handling and resolution of complaints:

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(1) Residential and small business customers shall directly contact the party responsible for the service in question as an initial step for complaint and problem resolution. If the customer mistakenly contacts the wrong entity, the customer shall be promptly referred to the appropriate contact. In the event of a power outage, the customer shall be directed to the EDC.

(2) Complaints that pertain to Chapter 56 (relating to standards and billing practices for residential utility service) matters shall be handled and resolved in accordance with the applicable standards in Chapter 56.

(3) EDCs and EGSs shall give the Commission access to disclosure statements, billing and other customer information resources for compliance reviews as deemed necessary by the Commission. When complaints arise and are brought before the Commission for resolution, the obligation of the EGS shall be extended to the provision of pricing information.

Cross References

This section cited in 52 Pa. Code § 54.1 (relating to purpose); and 52 Pa. Code § 111.13 (relating to customer complaints).

§ 54.10. Notice of contract expiration or change in terms for residential and small business customers.

An EGS shall provide the following notices to customers prior to the expiration of a fixed duration contract or prior to a change in contract terms:

(1) An initial notice shall be provided to each affected customer 45 to 60 days prior to the expiration date of the fixed duration contract or the effective date of the proposed change in terms. For customers who have elected to receive electronic communications from the EGS, the notice shall be transmitted in the manner chosen by the customer. The initial notice must include:

(i) A general description of the proposed change in terms of service.

(ii) The date a change shall be effective or when the fixed duration contract is to expire.

(iii) An explanation of why a change in contract terms is necessary.

(iv) A statement indicating when a follow-up options notice shall be issued with details regarding the proposed change.

(v) A statement explaining that the options notice must discuss the customer's options to the proposed change in terms of service or expiring fixed duration contract.

(vi) A statement indicating whether the existing fixed duration contract has a cancellation fee, and an explanation of the fee amount and how to avoid the fee, including a notice that the customer is not subject to the cancellation fee if the customer terminates the contract at any time after the customer receives the options notice required under § 54.10(2).

(2) An options notice shall be provided, by first class mail, to each affected customer at least 30 days prior to the expiration date of the fixed duration contract or the effective date of the proposed change in terms. The options notice must include:

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(i) A statement advising the customer of the specific changes being proposed by the EGS and informing the customer of how to exercise the customer's options, including the customer's ability to accept the proposed changes, to choose another product offering from the customer's existing EGS, to select another EGS or to return to default service.

(ii) Information regarding new pricing or renewal pricing including the price to be charged, per kilowatt-hour, for the first billing cycle of generation service:

(A) If a customer fails to respond to the options notice and is converted to a month-to-month contract, the EGS shall provide a disclosure statement under § 54.5 (relating to disclosure statement for residential and small business customers).

(I) Notice of a subsequent change in pricing shall be provided to the customer at least 30 days prior to the new price being charged.

(II) For customers who have elected to receive electronic communications from the EGS, notice of the change in pricing shall be transmitted in the manner chosen by the customer. For all other customers, notice shall be provided by first class mail.

(B) If a customer fails to respond to the options notice and is entered into a new fixed duration contract, the EGS shall provide the fixed, per kilowatt-hour price to be charged and term length of the contract.

(iii) The telephone numbers and Internet addresses, as applicable, for the Office of Consumer Advocate, the Commission and PaPowerSwitch.com.

(iv) Language clearly visible on the front of the envelope used to provide the options notice stating that it contains important information regarding the expiration or changes in terms of the customer's electric supply contract.

(v) A statement indicating whether the existing fixed duration contract has a cancellation fee and, if so, that the customer is not subject to the cancellation fee if the customer terminates the contract at any time between the date of the options notice and the expiration date of the fixed duration contract.

(3) When a customer fails to respond to either notice, the following apply:

(i) A fixed duration contract shall be converted to one of the following:

(A) A month-to-month contract, either at the same terms and conditions or at revised terms and conditions, as long as the contract does not contain cancellation fees.

(B) Another fixed duration contract, as long as the new contract includes a customer-initiated cancellation provision that allows the customer to cancel at any time, for any reason, and does not contain cancellation fees.

(ii) The converted contracts shall remain in place until the customer chooses one of the following options:

(A) Select another product offering from the existing EGS.

(B) Enroll with another EGS.

(C) Return to the default service provider.

Source

The provisions of this § 54.10 adopted June 13, 2014, effective June 14, 2014, 44 Pa.B. 3522; amended July 31, 2020, effective in 60 days, 50 Pa.B. 3861. Immediately preceding text appears at serial pages (372474) to (372475).

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Cross References

This section cited in 52 Pa. Code § 54.3 (relating to standards and pricing practices for retail electricity services); and 52 Pa. Code § 54.5 (relating to disclosure statement for residential for and small business customers).

Subchapter B. ELECTRICITY GENERATION SUPPLIER LICENSING

Sec.
54.31. Definitions.
54.32. Application process.
54.33. Application form.
54.34. Change in organizational structure or operational status.
54.35. Publication of notice of filing.
54.36. Protests to applications.
54.37. Approval.
54.38. Regulatory assessments.
54.39. Reporting requirements.
54.40. Bonds or other security.
54.41. Transfer or abandonment of license.
54.42. License suspension; license revocation.
54.43. Standards of conduct and disclosure for licensees.

Authority

The provisions of this Subchapter B issued under the Public Utility Code, 66 Pa.C.S. § 501; and the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801—2812, unless otherwise noted.

Source

The provisions of this Subchapter B adopted August 7, 1998, effective August 8, 1998, 28 Pa.B. 3760, unless otherwise noted.

§ 54.31. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise.

Aggregator—An entity licensed by the Commission, that purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers. See section 2803 of the code (relating to definitions).

Applicant—A person or entity seeking to obtain a license to supply retail electricity or electric generation service.

Broker—An entity, licensed by the Commission, that acts as an intermediary in the sale and purchase of electric energy but does not take title to electric energy. See section 2803 of the code.

Code—The Public Utility Code (66 Pa.C.S. Part I).

Default service provider—The incumbent EDC within a certificated service territory or a Commission approved alternative supplier of electric generation.

Department—The Department of Revenue of the Commonwealth.

EDC—Electric distribution company.

EGS—Electric generation supplier —

(i) A person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent

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provided prior to the effective date of this chapter (*Editor's Note:* The reference to "this chapter" refers to the code.), brokers and marketers, aggregators or any other entities, that sell to end-use customers electricity or related services utilizing the jurisdictional transmission and distribution facilities of an EDC, or that purchase, broker, arrange or market electricity or related services for sale to end-use customers utilizing the jurisdictional transmission and distribution facilities of an EDC.

(ii) The term excludes building or facility owner/operators that manage the internal distribution system serving the building or facility and that supply electric power and other related power services to occupants of the building or the facility.

(iii) The term excludes electric cooperative corporations except as provided in 15 Pa.C.S. Chapter 74 (relating to generation choice for customers of electric cooperatives). See section 2803 of the code.

Interim license—A temporary license granted to an EGS under interim standards adopted in the Commission's Final Order on Licensing Requirements for Electricity Generation Suppliers, entered February 13, 1997 at Dkt. No. M-00960890 F0004.

License—A license granted to an EGS under this subchapter.

Licensee—A person or entity which has obtained a license to provide retail electricity or electric generation service.

Market aggregator—An entity licensed by the Commission, that purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers. See section 2803 of the code.

Marketer—An entity, licensed by the Commission, that acts as an intermediary in the sale and purchase of electric energy but does not take title to electric energy. See section 2803 of the code.

Marketing—The publication, dissemination or distribution of informational and advertising materials regarding the EGS's services and products to the public by print, broadcast, electronic media, direct mail or by telecommunication.

Offer to provide service—The extension of an offer to provide services or products communicated orally, or in writing to a customer.

Renewable resource—As defined in section 2803 of the code.

Source

The provisions of this § 54.31 amended September 14, 2007, effective September 15, 2007, 37 Pa.B. 4996. Immediately preceding text appears at serial pages (247132) to (247133).

§ 54.32. Application process.

(a) An EGS may not engage in marketing, or may not offer to provide, or provide retail electricity or electric generation service until it is granted a license by the Commission.

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(b) An application for a license shall be made on the form provided by the Commission. A copy of the application may be obtained from the Commission's Secretary. The application form will also be made available on the Commission's Internet web site. An application shall be verified by an oath or affirmation as required in § 1.36 (relating to verification). See section 2809(b) of the code (relating to requirements for electric generation suppliers).

(c) An original of the completed application and supporting attachments shall be filed. An application for a license shall be accompanied by the application fee as established in § 1.43 (relating to schedule of fees payable to the Commission).

(d) Copies of the completed application with supporting documentation shall be served on the following: the Office of Consumer Advocate, the Office of Small Business Advocate, the Department and the Office of the Attorney General and the EDCs through whose transmission and distribution facilities the applicant intends to supply customers.

(e) Incomplete applications and those without supporting attachments, when needed, will be rejected without prejudice. The license application, with supporting attachments, shall be completed in its entirety.

(f) When an answer on the application requires the disclosure of privileged or confidential information not otherwise available to the public, the applicant may designate at each point in the application where information is disclosed that is confidential and privileged.

(1) One copy of this confidential or privileged information conspicuously marked at the top as ''CONFIDENTIAL'' may be submitted to the Office of the Secretary with the application. An applicant shall provide reasons for protecting this information.

(2) The request for confidentiality will be treated as a petition for protective order and will be ruled on by the Commission in conjunction with the license application.

(3) Pending disposition, the information will be used solely for the purpose of evaluating the license application, and the confidentiality of this information will be maintained consistent with regulations in this title pertaining to confidentiality.

(g) An EGS who has been granted an interim license shall apply for a license under this subchapter by updating its prior license application to include additional and updated information required by § 54.33 (relating to application form). An updated application shall be submitted by December 7, 1998.

(h) An EDC acting within its certificated service territory as a default service provider is not required to obtain a license.

Authority

The provisions of this § 54.32 amended under the Public Utility Code, 66 Pa.C.S. §§ 501, 504, 523, 1301, 1501 and 1504.

Source

The provisions of this § 54.32 amended September 14, 2007, effective September 15, 2007, 37 Pa.B. 4996; amended January 10, 2014, effective January 11, 2014, 44 Pa.B. 249. Immediately preceding text appears at serial pages (330045) to (330046).

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§ 54.33. Application form.

(a) The application form includes information that will be used in the evaluation of the financial fitness and technical fitness to render service. This information includes the following:

(1) An identification of the geographic area that the applicant proposes to serve.

(2) An identification of the type of service that the applicant proposes to furnish.

(3) An identification of the class of customers to which the applicant proposes to provide these services.

(4) An identification of the applicant's utility affiliates.

(5) A description of the applicant's business structure.

(6) Financial information sufficient to demonstrate financial fitness. This information may include credit ratings and history, audited financial statements, and insurance pertinent to the conduct of the applicant's business as an electric generation supplier.

(7) Evidence of competency and experience in providing the scope and nature of the applicant's proposed services. This evidence may include descriptions of the applicant's prior experience, proposed staffing and employe training commitments, business plans, and agreements, arrangements and contracts for generation, transmission and related services. Documentation of the applicant's membership in the East Central Area Reliability Coordination Agreement (ECAR), the Mid Atlantic Area Council (MAAC) or other National American Electric Reliability Council (NERC) regional reliability councils shall be submitted if applicable to the scope and nature of the applicant's proposed services.

(8) Evidence of information demonstrating the applicant's ability to comply with Commission's applicable requirements concerning customer billing, customer education, billing and terms of service, and customer information. This evidence may include prior regulatory experience of the applicant, prior business experience in energy or other service-oriented industries, staffing and staff training commitments, agreements, arrangements and contracts for customer education and information service, customer satisfaction survey results, government agency reports and complaint statistics compiled by the Better Business Bureau or similar business organizations.

(9) Certification that notice of the application was published in accordance with § 54.35 (relating to publication of notice of filing) shall be filed with the Commission's Secretary. The certification shall be notarized and include a photostatic copy of the notices as published. An application will not be considered complete for Commission review without this certification.

(b) The application also directs, under sections 2806(g)(3)(i), 2809(c)(1) and 2810(c)(6) of the code (relating to implementation, pilot programs and

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performance-based rates; requirements for electric generation suppliers; and revenue-neutral reconciliation), that the applicant provide tax information. This tax information includes:

(1) The name, address, telephone number, electronic numbers and addresses used to transmit tax and related information of the persons responsible for preparing and filing the applicant's Pennsylvania tax returns.

(2) Trade names or fictitious names used by the applicant.

(3) The type of business association (for example, sole proprietor, partnership and corporation).

(4) The names of the owners, general partners or corporate officers.

(5) The number of the applicant's current and anticipated employes working in this Commonwealth.

(6) An identification of the applicant's assets in this Commonwealth.

(7) The principal office in this Commonwealth or of its registered agent.

(8) An applicant's Department tax identification numbers including Sales Tax license number, employer identification number and corporate box number. If tax numbers have not yet been obtained, an applicant shall provide the filing date of its application for these numbers.

(c) Tax information provided under subsection (b) shall be filed with the Secretary of the Department at the time that application is made with the Commission.

Cross References

This section cited in 52 Pa. Code § 54.32 (relating to application process); and 52 Pa. Code § 54.39 (relating to reporting requirements).

§ 54.34. Change in organizational structure or operational status.

(a) The applicant is under a duty to inform the Commission of a material change in the information provided in the application during the pendency of the application, or while the licensee is operating in this Commonwealth.

(b) A material change in the organizational structure or operation that affects an applicant's or a licensee's operation in this Commonwealth shall be reported to the Commission within 30 days of the date of the change. Specifically, notification shall be given to the Commission of a change in the following:

(1) The ownership of generation or transmission facilities or other inputs to electric power production.

(2) An affiliation with an EDC, or an entity which owns generation or transmission facilities or other inputs to electric power production.

(3) An affiliation with an entity that has a franchised service area.

(c) Unless directed otherwise by the Commission, the licensee does not need to file an amended application with the Commission.

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§ 54.35. Publication of notice of filing.

(a) Notice of filing an application shall be published in newspapers of general circulation covering each county in which the applicant intends to provide service as required by § 5.14(a)(2) (relating to applications requiring notice). Applicants may contact the Commission's Press Secretary to confirm the identity of the newspapers of general circulation in which notice shall be published.

(b) The notice shall be written in plain language and include the name, address and telephone number of the applicant, a description of the proposed services to be provided and the geographic area to be served. The notice shall include the application docket number and a statement that protests related to the technical or financial fitness of the applicant shall be filed within 15 days of the publication date of the notice with the Commission's Secretary, Public Utility Commission, P. O. Box 3265, Harrisburg, PA 17105-3265. The notice in an acceptable electronic format shall be submitted to the Commission's Secretary for posting on the Commission's Internet web site and, if appropriate, on the Commission's electronic bulletin board.

Cross References

This section cited in 52 Pa. Code § 54.33 (relating to application form); and 52 Pa. Code § 62.104 (relating to application form).

§ 54.36. Protests to applications.

(a) Consistent with § 5.14(b) (relating to applications requiring notice), a 15-day protest period commences on the date notice of the application filing is published in newspapers. An interested party may file a protest to an application in compliance with § 5.52(a) (relating to content of a protest to an application) and shall set out clearly and concisely the facts upon which challenge to the fitness of the applicant is based. An applicant may file an answer to the protest within 10 days of when the protest is filed. Protests which do not fully comply with § 5.52(a) will be rejected.

(b) Protests may challenge only the applicant's financial and technical fitness to provide the service for which a license is requested. Consistent with the requirements of due process, sanctions, such as revocation or suspension of a supplier's license or the imposition of a fine, may be imposed on parties who intentionally misuse the protest process by repeated filing of competitive protests.

(c) A protest to the applicant's technical or financial fitness to provide service will be assigned to Commission staff for review. Staff will determine if the protest fully complies with § 5.52(a) and sets out clearly and concisely the facts upon which the challenge to the fitness of the applicant is based. Staff will determine if the protest is sufficiently documented. If a protest is not sufficiently documented, Commission staff will prepare a recommendation for Commission consideration dismissing the protest and granting the application. If a protest is sufficiently documented, the application will be transferred to the Office of Administrative Law Judge for hearings or mediation as deemed appropriate.

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§ 54.37. Approval.

(a) A license will be issued, authorizing the whole or any part of service requested, if the Commission finds that:

(1) The applicant is fit, willing and able to properly perform the service proposed in conformance with applicable provisions of the code and the lawful Commission orders and regulations, specifically including Chapter 56 (relating to Standards and Billing Practices for Residential Utility Service).

(2) The proposed service is consistent with the public interest and the policy declared in Chapter 28 of the code (relating to the Electricity Generation Customer Choice and Competition Act. See section 2809(b) of the code (relating to requirements for electric generation suppliers).

(b) Completed applications, with all supporting documentation, including any documentation or clarifying information requested by Commission staff, if unprotested, will be processed within 45 days after acceptance by the Commission. If the application is not processed within the time period, the application will be deemed approved. The review period may be extended for a reasonable period of time by Secretarial Letter.

§ 54.38. Regulatory assessments.

(a) A licensee shall be required to pay assessments to be used to defray regulatory costs. See section 510 of the code (relating to assessment for regulatory expenses upon public utilities). Assessments will be based upon the administrative costs incurred by the Commission related to generation suppliers. These costs include:

(1) Maintaining records related to licensees and administering other provisions of the code related to maintenance of adequate reserve margins.

(2) Compliance with Chapter 56 (relating to standards and billing practices for residential utility service).

(3) Fulfilling consumer information and education obligations.

(b) Yearly assessments shall be paid by the licensee within 30 days of receipt of notice of the amount lawfully charged against it as a condition of maintaining a license to supply electricity or electric generation. See section 510(c) of the code.

Notes of Decisions

Conflict with Statute

To the extent that the provisions of § 54.38 can be construed as contrary to the statute under which it was promulgated, then the regulation is invalid so far as it prohibits the grouping of electric generation supplier companies for purposes of assessment. *PPL Energyplus, LLC v. Commonwealth*, 800 A.2d 360 (Pa. Cmwlth. 2002).

§ 54.39. Reporting requirements.

(a) A licensee shall report its level of gross receipts to the Commission on a quarterly basis. Gross receipt information shall be filed with the Commission within the 30 days following the end of the first full quarter, and of each subsequent quarter that the license is in effect.

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(b) A licensee shall file an annual report on or before April 30 of each year, for the previous calendar year. The annual report shall contain the following information (See section 2810(c)(6) of the code (relating to revenue-neutral reconciliation):

(1) Updates to the tax information requested in the application in § 54.33(b) (relating to application form).

(2) The total amount of gross receipts from the sales of electricity for the preceding calendar year.

(3) The total amount of electricity sold, stated in kilowatt hours, during the preceding calendar year.

(4) The percentage of total electricity supplied by each energy source, including a detailed breakdown of renewable resources as defined in section 2803 of the code (relating to definitions).

(c) A licensee shall be required to meet periodic reporting requirements as may be issued by the Commission to fulfill the Commission's duty under Chapter 28 of the code (relating to Electricity Generation Customer Choice and Competition Act) pertaining to reliability and to inform the Governor and Legislature of the progress of the transition to a fully competitive electric market.

(d) The information requested in this section will be made available for public review upon request to the Commission subject to any rulings on confidentiality made by the Commission.

§ 54.40. Bonds or other security.

(a) A license will not be issued or remain in force until the licensee furnishes a bond or other security approved by the Commission. See section 2809(c) of the code (relating to requirements for electric generation suppliers).

(b) The purpose of the security requirement is to ensure the licensee's financial responsibility, the payment of gross receipts tax as required by section 2810 of the code (relating to revenue-neutral reconciliation), and the supply of electricity at retail in accordance with contracts, agreements or arrangement. See section 2809(c) of the code.

(c) The initial security level required from each applicant is $250,000. Modifications of this amount commensurate with the nature and scope of business anticipated to be conducted in this Commonwealth may be granted where substantial evidence is submitted in support of the modification. A request for modification of this initial security level may be made in conjunction with the filing of the application. The license will be issued contingent on the submission of proof that the applicant has obtained a bond, or other approved security in the amount directed by the Commission.

(d) After the first year that the license is in effect, the security level for each licensee will be reviewed annually and modified primarily based on the licensee's reported annual gross receipts information. The security level will be 10% of the licensee's reported gross receipts. See section 2809 (c)(1)(i) of the code. Maintenance of a license will be contingent on the licensee providing proof to the

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Commission that a bond or other approved security in the amount directed by the Commission has been obtained. A licensee may seek approval from the Commission of an alternative level of bonding commensurate with the nature and scope of its operations.

(e) Payments pursuant to the security may result from the licensee's failure to pay the full amount of Gross Receipt Taxes, or failure to supply electricity or other services in accordance with contracts, agreements or arrangements.

(f) The bond or security shall include the following:

(1) The Pennsylvania Public Utility Commission, Commonwealth as the sole beneficiary.

(2) The purpose of the bond as follows:

This bond (or other security) is written in accordance with Section 2809(c)(1)(i) of the Public Utility Code, 66 Pa.C.S. § 2809(c)(1)(i), to assure compliance with applicable provisions of the Public Utility Code, 66 Pa.C.S. §§ 101, et seq., and the rules and regulation of the Pennsylvania Public Utility Commission by the Principle as a licensed electric generation supplier; to ensure the payment of Gross Receipts Tax as required by Section 2810 of the Public Utility Code, 66 Pa.C.S. § 2810; and to ensure the supply of electricity at retail in accordance with contracts, agreements or arrangements.

(3) A listing of the prioritization of claims for payment under the security from highest priority to lowest priority as follows:

(i) The Commonwealth.

(ii) EDCs for the reimbursement of Gross Receipts Tax.

(c) Private individuals.

(4) A statement that the security shall be interpreted under law of the Commonwealth, or in the alternative, no choice of law is specified.

(g) The applicant may request the use of a security other than a bond. See section 2809 (c)(1)(i) of the code. The application shall include specific information about the licensee's need to use a security other than a bond; and shall provide the name, business address, the nature of the business of the entity issuing the security, and if available, the financial rating of the entity. The applicant shall demonstrate that the financial protection afforded by the security is equivalent to that of a bond.

(h) Licensee liability for unreasonable service, or for violations of the code and Commission orders and regulations is not limited by these security requirements.

§ 54.41. Transfer or abandonment of license.

(a) A license may not be transferred without prior Commission approval. See section 2809(d) of the code (relating to requirements for electric generation suppliers). Approval for transfer shall be obtained by petition to the Commission. The granting of such a petition does not eliminate the need for the transferee to

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complete and file with the Commission an application that demonstrates the transferee's financial and technical fitness to render service under the transferred license.

(b) A licensee may not abandon service without providing 90 days prior written notice to the Commission, the licensee's customers, the affected distribution utilities and default service providers prior to the abandonment of service. The licensee shall provide individual notice to its customers with each billing, in each of the three billing cycles preceding the effective date of the abandonment.

Source

The provisions of this § 54.41 amended September 14, 2007, effective September 15, 2007, 37 Pa.B. 4996. Immediately preceding text appears at serial page (247140).

Cross References

This section cited in 52 Pa. Code § 54.123 (relating to transfer of customers to default service).

§ 54.42. License suspension; license revocation.

(a) A licensee shall comply with the applicable requirements of the code and Commission regulations and orders. Consistent with due process, a license may be suspended or revoked, and fines may be imposed against the licensee for:

(1) The failure to pay the yearly assessment.

(2) The failure to furnish and maintain a bond or other security approved by the Commission in the amount directed by the Commission.

(3) The nonpayment of taxes under Article II of the Tax Reform Code of 1971 (72 P. S. §§ 7201—7281.2) and Article XI of the Tax Reform Code of 1971 (72 P. S. §§ 8101—8104) and any taxes imposed by Chapter 28 of the code (relating to Electricity Generation Customer Choice and Competition Act). See sections 2806(g)(3) and 2809(c)(1) of the code (relating to implementation, pilot program and performance based rates; and requirements for electric generation suppliers).

(4) The failure to waive confidentiality with respect to tax information in the possession of the Department. See section 2810(c)(6)(iv) of the code (relating to revenue-neutral reconciliation).

(5) The failure to provide the address of its principal office in this Commonwealth or of its registered agent.

(6) The failure to follow the principles in § 54.43 (relating to standards of conduct and disclosure for licensees).

(7) A violation of applicable provisions of the code, this title and lawful Commission orders. See section 2809(b) of the code.

(8) A violation of Pennsylvania consumer protection law.

(9) The transfer of a customer without the customer's consent. See section 2807(d)(1) of the code (relating to duties of electric distribution companies).

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Cross References

This section cited in 52 Pa. Code § 54.123 (relating to transfer of customers to default service).

§ 54.43. Standards of conduct and disclosure for licensees.

To protect consumers of this Commonwealth, licensees shall adhere to the following principles in the provision of electric generation service:

(1) A licensee shall provide accurate information about their electric generation services using plain language and common terms in communications with consumers. When new terms are used, the terms shall be defined again using plain language. Information shall be provided in a format that enables customers to compare the various electric generation services offered and the prices charged for each type of service.

(b) A licensee shall respond to reasonable consumer requests for information regarding energy sources by percentage, and plant emissions of its electric generation supply.

(c) A licensee shall provide notification of change in conditions of service, intent to cease operation as an electric generation supplier, explanation of denial of service, proper handling of deposits and proper handling of complaints in accordance with this title.

(d) A licensee shall maintain the confidentiality of a consumer's personal information including the name, address and telephone number, and historic payment information, and provide the right of access by the consumer to his own load and billing information.

(e) A licensee may not discriminate in the provision of electricity as to availability and terms of service based on race, color, religion, national origin, sex, marital status, age, receipt of public assistance income, and exercise of rights under Subchapter IV of the Consumer Credit Protection Act (15 U.S.C.A. §§ 1691—1691f), relating to Equal Credit Opportunity. See 12 CFR 202-1—202.14 (relating to equal credit opportunity Regulation B).

(f) A licensee is responsible for any fraudulent deceptive or other unlawful marketing or billing acts performed by the licensee, its employes, agents or representatives. Licensee shall inform consumers of state consumer protection laws that govern the cancellation or rescission of electric generation supply contracts. See section 7 of the Unfair Trade Practices and Consumer Protection Law (73 P. S. § 201-7).

(g) A licensee shall comply with relevant Commission regulations, orders and directives that may be adopted.

Cross References

This section cited in 52 Pa. Code § 54.42 (relating to license suspension; license revocation); 52 Pa. Code § 111.3 (relating to supplier liability for its agent); 52 Pa. Code § 111.5 (relating to agent training); and 52 Pa. Code § 111.12 (relating to consumer protection).

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Subchapter C. UNIVERSAL SERVICE AND ENERGY CONSERVATION REPORTING REQUIREMENTS

Sec.
54.71. Statement of purpose and policy.
54.72. Definitions.
54.73. Universal service and energy conservation program goals.
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54.75. Annual residential collection universal service and energy conservation program reporting requirements.
54.76. Evaluation reporting requirements.
54.77. Electric distribution companies with less than 60,000 residential accounts.
54.78. Public information.

Authority

The provisions of this Subchapter C issued under the Public Utility Code, 66 Pa.C.S. § 501; and the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. § 2801—2812, unless otherwise noted.

Source

The provisions of this Subchapter C adopted August 7, 1998, effective August 8, 1998, 28 Pa.B. 3793, unless otherwise noted.

§ 54.71. Statement of purpose and policy.

Section 2804(9) of the code (relating to standards for restructing of electric industry) mandates that the Commission ensure universal service and energy conservation policies, activities and services for residential electric customers are appropriately funded and available in each EDC territory. This subchapter requires covered EDCs to establish uniform reporting requirements for universal

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service and energy conservation policies, programs and protections and to report this information to the Commission.

§ 54.72. Definitions.

The following words and terms, when used in this chapter, have the following meanings, unless the context clearly indicates otherwise:

CAP—Customer Assistance Program—An alternative collection method that provides payment assistance to low-income, payment troubled utility customers. CAP participants agree to make regular monthly payments that may be for an amount that is less than the current bill in exchange for continued provision of electric utility services.

CAP benefits—The average CAP bill, average CAP credits and average arrearage forgiveness.

CARES—A program that provides a cost-effective service that helps selected, payment-troubled customers maximize their ability to pay utility bills. A CARES program provides a casework approach to help customers secure energy assistance funds and other needed services.

CARES benefits—The number and kinds of referrals to CARES.

Classification of accounts—Accounts are classified by the following categories: all residential accounts and confirmed low-income residential accounts.

Code—The Public Utility Code, 66 Pa.C.S. §§ 101—3316.

Collection operating expenses—Expenses directly associated with collection of payments due for residential accounts.

Confirmed low-income residential account—Accounts where the EDC has obtained information that would reasonably place the customer in a low-income designation.

Direct dollars—Dollars which are applied to a CARES customer's electric utility account, including all sources of energy assistance applied to utility bills such as LIHEAP, hardship fund grants and local agencies' grants.

EDC—Electric distribution company—The public utility providing facilities for the jurisdictional transmission and distribution of electricity to retail customers, except building or facility owners/operators that manage the internal distribution system serving the building or facility and that supply electric power and other related electric power services to occupants of the building or facility.

Energy assistance benefits—The total number and dollar amount of LIHEAP grants.

Hardship fund—A fund that provides cash assistance to utility customers to help them pay their utility bills.

Hardship fund benefits—The total number and dollar amount of cash benefits or bill credits.

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Impact evaluation—An evaluation that focuses on the degree to which a program achieves the continuation of utility service to program participants at a reasonable cost level and otherwise meets program goals.

LIURP—Low-income usage reduction program—An energy usage reduction program that assists low-income customers conserve energy and reduce residential energy bills.

Low-income customer—A residential utility customer whose household income is at or below 150% of the Federal poverty guidelines.

Outreach referral contacts—Addresses and telephone numbers that a customer would call or write to apply for the hardship fund. Contact information should be specific to each county in the EDC's service territory, if applicable.

Payment rate—Payment rate is the total number of full monthly payments received from CAP participants in a given period divided by the total number of monthly bills issued to CAP participants.

Payment troubled—A household that has failed to maintain one or more payment arrangements in a 1-year period.

Residential account in arrears—A residential account that is at least 30 days overdue. This classification includes all customer accounts which have payment arrangements.

Successful payment arrangements—A payment arrangement in which the agreed upon number of payments have been made in full in the preceeding 12 months.

Universal service and energy conservation—Policies, protections and services that help low-income customers to maintain electric service. The term includes customer assistance programs, termination of service protection and policies and services that help low-income customers to reduce or manage energy consumption in a cost-effective manner, such as the low-income usage reduction programs, application of renewable resources and consumer education.

Cross References

This section cited in 52 Pa. Code Chapter 56 Appendix C (relating to definitions (§ 56.231)).

§ 54.73. Universal service and energy conservation program goals.

(a) The Commission will determine if the EDC meets the goals of universal service and energy conservation programs.

(b) The general goals of universal service and energy conservation programs include the following:

(1) To protect consumers' health and safety by helping low-income customers maintain electric service.

(2) To provide for affordable electric service by making available payment assistance to low-income customers.

(3) To assist low-income customers conserve energy and reduce residential utility bills.

(4) To establish universal service and energy conservation programs are operated in a cost-effective and efficient manner.

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§ 54.74. Universal service and energy conservation plans.

(a) *Plan submission.*

(1) Each EDC shall submit to the Commission for approval an updated universal service and energy conservation plan every 3 years beginning February 28, 2000, on a staggered schedule.

(2) The plan should cover the next 3-calendar years.

(3) The plan should state how it differs from the previously approved plan.

(4) The plan should include revisions based on analysis of program experiences and evaluations.

(5) If the Commission rejects the plan, the EDC shall submit a revised plan under the order rejecting or directing modification of the plan as previously filed. If the order rejecting the plan does not state a timeline, the EDC shall file its revised plan within 45 days of the entry of the order.

(6) The Commission will act on the plans within 90 days of the EDC filing date.

(b) *Plan contents.* The components of universal service and energy conservation may include the following: CAP, LIURP, CARES, Hardship Funds and other programs, policies and protections. For each component of universal service and energy conservation, the plan shall include, but not be limited to, the following:

(1) Program description.

(2) Eligibility criteria.

(3) Projected needs assessment.

(4) Projected enrollment levels.

(5) Program budget.

(6) Plans to use community-based organizations.

(7) Organizational structure of staff responsible for universal service programs.

(8) Explanation of any differences between the EDC's approved plan and the implementation of that plan. The EDC should include a plan to address those differences.

Cross References

This section cited in 52 Pa. Code § 54.77 (relating to electric distribution companies with less than 60,000 residential accounts).

§ 54.75. Annual residential collection and universal service and energy conservation program reporting requirements.

Each EDC shall report annually to the Commission on the degree to which universal service and energy conservation programs within its service territory are available and appropriately funded. Annual EDC reports shall contain information on programs and collections for the prior calendar year. Unless otherwise stated, the report shall be due April 1 each year, beginning April 1, 2001. Where noted,

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the data shall be reported by classification of accounts. Each EDC's report shall contain the following information:

(1) Collection reporting shall be categorized as follows:

(i) The total number of payment arrangements and the total number of successful payment arrangements. To ensure that successful payment arrangements are not overstated, EDCs should report on the calendar year prior to the reporting year.

(ii) Annual collection operating expenses by classification of accounts. Collection operating expenses include administrative expenses associated with termination activity, negotiating payment arrangements, budget counseling, investigation and resolving informal and formal complaints associated with payment arrangements, securing and maintaining deposits, tracking delinquent accounts, collection agencies' expenses, litigation expenses other than Commission related, dunning expenses and winter survey expenses.

(iii) The total dollar amount of the gross residential write-offs and total dollar amount of the net residential write-offs, by classification of accounts.

(iv) The total number of residential customers by month for the 12 months covered by the report, by classification of accounts.

(v) The total number of residential accounts in arrears by month for the 12 months covered by the report, by classification of accounts.

(vi) The total dollar amount of residential accounts in arrears by month for the 12 months covered by the report, by classification of accounts.

(vii) The total number of residential customers who are payment troubled by month for the 12 months covered by the report, by classification of accounts.

(viii) The total number of terminations completed by month for the 12 months covered by the report, by classification of accounts.

(ix) The total number of reconnections by month for the 12 months covered by the report, by classification of accounts.

(x) The total number of low-income households. EDCs may estimate this number using census data or other information the EDC finds appropriate.

(2) Program reporting shall be categorized as follows:

(i) For each universal service and energy conservation component, program data shall include information on the following:

(A) Program costs.

(B) Program recipient demographics, including the number of family members under age 18 and over age 62, family size, income and source of income.

(C) Participation levels by month for the 12 months covered by the report.

(ii) Additional program data for individual universal service and energy conservation components shall include the following information:

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(A) *LIURP.* Reporting requirements as established at § 58.15 (relating to program evaluation).

(I) LIURP reporting data shall be due by April 30.

(II) Actual production and spending data for the recently completed program year and projections for the current year shall be due annually by the end of February.

(B) *CAP.*

(I) Energy assistance benefits.

(II) Average CAP bills.

(III) Payment rate.

(IV) CAP benefits.

(V) Total cash payments by CAP customers.

(VI) Number of full, on-time payments

(VII) Percentage of CAP bill paid by customer.

(C) *CARES.*

(I) Energy assistance benefits.

(II) Direct dollars applied to CARES accounts.

(III) CARES benefits.

(D) *Hardship funds.*

(I) Ratepayer contributions.

(II) Special contributions.

(III) Utility contributions.

(IV) Outreach contacts.

(V) Hardship fund benefits.

Cross References

This section cited in 52 Pa. Code § 54.77 (relating to electric distribution companies with less than 60,000 residential accounts).

§ 54.76. Evaluation reporting requirements.

(a) Each EDC shall have an independent third-party conduct an impact evaluation of its universal service and energy conservation programs and provide a report of findings and recommendations to the Commission and EDC.

(b) The first impact evaluation will be due beginning October 31, 2002, on a staggered schedule. Subsequent evaluation reports shall be presented to the EDC and the Commission at no more than 6 year intervals.

(c) To ensure an independent evaluation, neither the EDC nor the Commission shall exercise control over content or recommendations contained in the independent evaluation report. The EDCs may provide the Commission with a companion report that expresses where they agree or disagree with independent evaluation report content or recommendations.

(d) An independent third-party evaluator shall conduct the impact evaluation.

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Cross References

This section cited in 52 Pa. Code § 54.77 (relating to electric distribution companies with less than 60,000 residential accounts); and 52 Pa. Code § 69.265 (relating to CAP design elements).

§ 54.77. Electric distribution companies with less than 60,000 residential accounts.

Beginning March 1, 2000, each EDC with less than 60,000 accounts shall report to the Commission every 3 years the following information in lieu of §§ 54.74—54.76 (relating to universal service and energy conservation plans; annual residential collection and universal service and energy conservation program reporting requirements; and evaluation reporting requirements):

(1) The universal service and energy conservation plan.

(2) Expenses associated with low-income customers.

(3) A description of the universal service and energy conservation services provided to low-income residential customers.

(4) The number of services or benefits provided to low-income residential customers.

(5) The dollar amount of services or benefits provided to low-income residential customers.

§ 54.78. Public information.

The Commission will annually produce a summary report on the universal service performance of each EDC using the statistics collected as a result of these reporting requirements. The reports will be public information. The Commission will provide the reports to any interested party and post the reports on the Commission's Internet Website.

Subchapter D. ADJUSTMENT OF ELECTRIC DISTRIBUTION COMPANY RATES FOR CHANGES IN STATE TAX LIABILITY

Sec.

54.91. Purpose.
54.92. Definitions.
54.93. Manner of filing.
54.94. Recovery of changes in State tax liability.
54.95. Recovery of RNR tax liability producing rates above the rate cap.
54.96. Recovery of sections 2806(g) and 2809(c) tax liability producing rates above the rate cap.
54.97. State tax adjustment surcharge.
54.98. Customer notice requirements.

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Authority

The provisions of this Subchapter D issued under the Public Utility Code, 66 Pa.C.S. §§ 501 and 1301; and the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. § 2804(16), unless otherwise noted.

Source

The provisions of this Subchapter D adopted August 7, 1998, effective August 8, 1998, 28 Pa.B. 3775, unless otherwise noted.

§ 54.91. Purpose.

This subchapter implements Chapter 28 of the code (relating to Electricity Generation Customer Choice and Competition Act) governing adjustments to the rates of an EDC to reflect changes in its State tax liability. This subchapter establishes the time, manner, form and information content of the filings required by an EDC seeking recovery of changes in its State tax liability. This subchapter also establishes specialized procedures to supplement existing procedures relating to public utility rate changes. Finally, this subchapter establishes the effective dates of relevant EDC rate adjustments and the applicable customer notification requirements for these adjustments.

§ 54.92. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

CTC—Competitive transition charge—The competitive transition charge as defined in section 2803 of the code (relating to definitions).

Code—The Public Utility Code, 66 Pa.C.S. §§ 101—3316.

Customer—A retail electric customer as defined in section 2803 of the code.

Department—The Department of Revenue of the Commonwealth.

EDC—Electric distribution company—An EDC as defined in section 2803 of the code.

Electric generation supplier or *electricity supplier*—An electric generation supplier or an electricity supplier as defined in section 2803 of the code.

ITC—Intangible transition charge—The intangible transition charge as defined in section 2812(g) of the code (relating to approval of transition bonds).

Rate cap or *price cap*—The limits on the allowable charges of an EDC, and the exceptions and exclusions from these limits, as prescribed by section 2804(4) of the code (relating to standards for restructuring of electric industry).

RNR—Revenue neutral reconciliation—Section 2810 of the code (relating to revenue-neutral reconciliation).

STAS—State tax adjustment surcharge—The State tax adjustment surcharge as defined in § 69.51 (relating to definitions).

Transition or *stranded costs*—The transition or stranded costs as defined in section 2803 of the code.

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§ 54.93. Manner of filing.

Each proposed change in rates in this subchapter shall be perfected in accordance with § 53.51(c) (relating to general) and shall be served in accordance with § 53.51(d).

§ 54.94. Recovery of changes in State tax liability.

(a) The Commission will permit an EDC to recover from customers changes in its State tax liability arising from sections 2806(g), 2809(c) and 2810 of the code (relating to implementation, pilot programs and performance-based rates; requirements for electric generation suppliers; and revenue-neutral reconciliation) and §§ 69.51—69.56 (relating to inclusion of State taxes and gross receipts taxes in base rates) to the extent that the resulting rates do not exceed the rate or price cap.

(b) An EDC seeking recovery of changes in its State tax liability under this section shall provide the following information to the Commission:

(1) A description of the surcharge proposed by the EDC, and a statement of reasons for the proposed rate change.

(2) A statement that the surcharge becomes effective for service rendered beginning 60 days after the filing of the tariffs or tariff supplements.

(3) If applicable, the calculations supporting the amount of its tax liability arising from the RNR.

(4) If applicable, the amount of payments under sections 2806(g) and 2809(c) of the code for the immediately preceding 12-month period ending on June 30, plus interest accrued at 6% per year from the time of payment until the time the payments are reflected in customer rates, supported by a copy of the notification received from the Department assessing these taxes and related interest.

(5) If applicable, an affidavit which states that the EDC has not recovered the taxes through tariff indemnification tariff provisions or other means, and that the Department has assessed the taxes.

Cross References

This section cited in 52 Pa. Code § 54.97 (relating to State tax adjustment surcharge); and 52 Pa. Code § 54.98 (relating to customer notice requirements).

§ 54.95. Recovery of RNR tax liability producing rates above the rate cap.

(a) An EDC proposing to increase its rates above the rate cap due to the RNR shall file a single issue rate proceeding under section 1308(a) of the code (relating to voluntary changes in rates).

(b) The EDC's filing provides information which enables the Commission to determine if the filing is an accurate claim for the amount of its tax liability arising from the RNR and whether recovery of its RNR tax liability causes the resulting rates to exceed the rate cap.

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(c) Within 30 days of receiving the Department's notice of the change in the applicable tax rate established by the RNR, an EDC proposing to increase its rates as described in this section shall provide the following information to the Commission:

(1) A statement that the reason for the proposed rate increase is to permit the EDC to recover that portion of its RNR tax liability that produces rates above the rate cap.

(2) A proof of revenue calculation by rate class demonstrating the impact of the proposed rate increase upon each class of customers. The EDC shall, at a minimum, show both the dollar and percentage change being proposed for each tariffed rate.

(3) A description of the surcharge for recovering the increased tax liability.

(4) A notice that the surcharge becomes effective 60 days from the date the EDC files the proposed rate increase.

Cross References

This section cited in 52 Pa. Code § 54.98 (relating to customer notice requirements).

§ 54.96. Recovery of sections 2806(g) and 2809(c) tax liability producing rates above the rate cap.

(a) The Commission will permit an EDC to recover, through its State Tax Adjustment Surcharge or other appropriate mechanism, changes in its State tax liability and related interest under sections 2806(g) and 2809(c) of the code (relating to implementation, pilot programs and performance-based rates; and requirements for electric generation suppliers) when that recovery produces rates above the rate cap, upon certification by affidavit that the following apply:

(1) The EDC has not recovered the taxes due pursuant to its tariff indemnification provisions.

(2) The Department has not collected the taxes due under the other means set forth in sections 2806(g)(3)(iii) and 2809(c)(2).

(b) In addition to the affidavit required under subsection (a), the EDC shall file with the Commission:

(1) A statement of the amount of payments under section 2806(g) or 2809(c) for the immediately preceding 12-month period ending on June 30, plus interest accrued at 6% per year from the time of payment until the time the payments are reflected in customer rates, supported by a copy of the notification received from the Department assessing these taxes and related interest.

(2) A proof of revenue calculation by rate class demonstrating the impact of the proposed rate increase upon each class of customers. The dollar and percentage changes shall be shown for each tariffed rate.

(3) A description of the surcharge for recovering the increased tax liability.

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(4) A statement that the surcharge becomes effective for service rendered beginning 60 days after the filing of tariffs or tariff supplements.

Cross References

This section cited in 52 Pa. Code § 54.98 (relating to customer notice requirements).

§ 54.97. State tax adjustment surcharge.

(a) *Surcharge calculation.* Every EDC subjected to new or increased State taxes under sections 2806(g), 2809(c) and 2810 of the code (relating to implementation, pilot programs and performance-based rates; requirements for electric generation suppliers; and revenue-neutral reconciliation) and §§ 69.51—69.56 (relating to inclusion of State taxes and gross receipts taxes in base rates) that proposes to modify its STAS to recover these taxes shall include the following information in its surcharge calculation:

(1) The amounts paid under sections 2806(g) and 2809(c) for the immediately preceding 12-month period ending on June 30, plus interest accrued at 6% per year from the time of payment until the time the payments are reflected in customer rates. The EDC shall also provide an affidavit that it has not recovered these taxes under the other means in sections 2806(g)(3)(iii) and 2809(c)(2) of the code.

(2) Adjustments to the gross receipts tax rate pursuant to the RNR.

(3) When applicable, paragraphs (1) and (2) shall be added to any other amounts recoverable under the STAS.

(4) The total of paragraph (3) divided by a factor which is the complement of the Gross Receipts Tax (GRT) rate (1 minus the GRT rate), adjusted by the RNR to the extent that recovery is approved by the Commission under section 2804(16) of the code (relating to standards for restructuring of electric industry).

(5) The quotient of paragraph (4) divided by gross intrastate operating revenues derived from service under rates subject to the jurisdiction of the Commission for the most recently completed calendar year, exclusive of the revenues produced by the surcharge permitted by subsection (a). This quotient shall be expressed as a percentage.

(2) If the EDC increased or decreased its rates under the Commission's jurisdiction during or after the most recently completed calendar year, it shall include in its computation the appropriate adjustments to paragraphs (1)—(5), as if the increased or decreased rates had been in effect for all of that calendar year.

(b) For rate changes that require the STAS to be filed under this section, every EDC shall provide the following information to the Commission:

(1) For a change in an EDC's RNR tax liability contained in a notice from the Department, the information described in § 54.94(b)(3) (relating to recovery of changes in State tax liability).

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(2) For amounts paid by an EDC under sections 2806(g) and 2809(c) of the code, the information described in § 54.94(b)(4).

(c) Every tariff or tariff supplement modifying an EDC's STAS under this section shall carry an effective date which shall be 10 days after its filing with the Commission and shall be applicable for service rendered on or after the effective date.

§ 54.98. Customer notice requirements.

(a) An EDC proposing to increase its rates under § 54.94 or § 54.96 (relating to recovery of changes in State tax liability; and recovery of sections 2806(g) and 2809(c) tax liability producing rates above the rate cap) shall provide customer notice as provided in § 53.45(g) (relating to public notice of new tariffs and tariff changes).

(b) An EDC proposing to increase its rates under § 54.95 (relating to recovery of RNR tax liability producing rates above the rate cap) shall provide customer notice and follow the tariff posting procedures in §§ 53.41—53.45 (relating to posting of tariffs and notices).

Subchapter E. COMPETITIVE SAFEGUARDS

Sec.
54.121. Purpose.
54.122. Code of conduct.
54.123. Transfer of customers to default service.

Authority

The provisions of this Subchapter E issued under the Public Utility Code, 66 Pa.C.S. §§ 501, 502, 504—506, 508, 701, 1301, 1304, 1501, 1502, 1505, 1701—1705, 2101—2107 and 2801—2811, unless otherwise noted.

Source

The provisions of this Subchapter E adopted July 7, 2000, effective July 8, 2000, 30 Pa.B. 3445, unless otherwise noted.

§ 54.121. Purpose.

The purpose of these competitive safeguards is to assure the provision of direct access on equal and nondiscriminatory terms to all customers and generation suppliers, prevent discrimination in rates, terms or conditions of service by electric distribution companies, prevent the cross subsidization of service amongst customers, customer classes or between related electric distribution companies and electric generation suppliers, to forbid unfair or deceptive practices by electric generation companies and electric generation suppliers, and to establish and maintain an effective and vibrant competitive market in the purchase and sale of retail electric energy in this Commonwealth.

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§ 54.122. Code of conduct.

Electric generation suppliers and electric distribution companies shall comply with the following requirements:

(1) An electric distribution company may not give an electric generation supplier, including without limitation, its affiliate or division, any preference or advantage over any other electric generation supplier in processing a request by a distribution company customer for retail generation supply service.

(2) Subject to customer privacy or confidentiality constraints, an electric distribution company may not give an electric generation supplier, including without limitation its affiliate or division, any preference or advantage in the dissemination or disclosure of customer information and any dissemination or disclosure shall occur at the same time and in an equal and nondiscriminatory manner. ''Customer information'' means all information pertaining to retail electric customer identity and current and future retail electric customer usage patterns, including appliance usage patterns, service requirements or service facilities.

(3) An electric distribution company or electric generation supplier may not engage in false or deceptive advertising to customers with respect to the retail supply of electricity in this Commonwealth.

(4) Each electric distribution company shall adopt the following dispute resolution procedures to address alleged violations of this section:

(i) Regarding any dispute between an electric distribution company or a related supplier, or both, and an electric generation supplier (each individually referred to as a ''party'' and collectively referred to as ''parties''), alleging a violation of any of the provisions of this section, the electric generation supplier shall provide the electric distribution company or related supplier, or both, as applicable, a written notice of dispute which includes the names of the parties and customers, if any involved and a brief description of the matters in dispute.

(ii) Within 5 days of receipt of the notice by the electric distribution company or related supplier, or both, a designated senior representative of each of the parties shall attempt to resolve the dispute on an informal basis.

(iii) If the designated representatives are unable to resolve the dispute by mutual agreement within 30 days of the referral, the dispute shall be referred for mediation through the Commission's Office of Administrative Law Judge. A party may request mediation prior to that time if it appears that informal resolution is not productive.

(iv) If mediation is not successful, the matter shall be converted to a formal proceeding before a Commission administrative law judge, and the prosecuting parties shall be directed to file a formal pleading in the nature of a complaint, petition or other appropriate pleading with the Commission within 30 days or the matter will be dismissed for lack of prosecution. Any

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party may file a complaint, petition or other appropriate pleading concerning the dispute under any relevant provision of 66 Pa.C.S. (relating to the Public Utility Code).

(5) An electric distribution company may not illegally tie the provision of any electric distribution service within the jurisdiction of the Commission to one of the following:

(i) The purchase, lease or use of any other goods or services offered by the electric distribution company or its affiliates.

(ii) A direct or indirect commitment not to deal with any competing electric generation supplier.

(6) An electric distribution company may not provide any preference or advantage to any electric generation supplier in the disclosure of information about operational status and availability of the distribution system.

(7) An electric distribution company shall supply all regulated services and apply tariffs to nonaffiliated electric generation suppliers in the same manner as it does for itself and its affiliated or division electric generation supplier, and shall uniformly supply all regulated services and apply its tariff provisions in a nondiscriminatory manner.

(8) Every electric distribution company and its affiliated or divisional electric generation supplier shall formally adopt and implement these provisions as company policy and shall take appropriate steps to train and instruct its employes in their content and application.

(9) If an electric distribution company customer requests information about electric generation suppliers, the electric distribution company shall provide the latest list as compiled by the Commission to the customer over the telephone, or in written form or by other equal and nondiscriminatory means. In addition, an electric distribution company may provide the address and telephone number of an electric generation supplier if specifically requested by the customer by name. To enable electric distribution companies to fulfill this obligation, the Commission will maintain a written list of licensed electric generation suppliers. The Commission will regularly update this list and provide the updates to electric distribution companies as soon as reasonably practicable. The Commission will compile the list in a manner that is fair to all electric generation suppliers and that is not designed to provide any particular electric generation supplier with a competitive advantage.

(10) An electric distribution company or its affiliate or division may not state or imply that any delivery services provided to an affiliate or division or customer of either are inherently superior, solely on the basis of their affiliation with the electric distribution company, to those provided to any other electric generation supplier or customer or that the electric distribution company's delivery services are enhanced should supply services be procured from its affiliate or division. When an electric distribution company's affiliated or divisional supplier markets or communicates to the public using the electric distribution company's name or logo, it shall include a disclaimer stating that the

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affiliated or divisional supplier is not the same company as the electric distribution company, that the prices of the affiliated or divisional supplier are not regulated by the Commission and that a customer is not required to buy electricity or other products from the affiliated or divisional supplier to receive the same quality service from the electric distribution company. When an affiliated or divisional supplier advertises or communicates through radio, television or other electronic medium to the public using the electric distribution company's name or logo, the affiliated or divisional supplier shall include at the conclusion of any communication a disclaimer that includes all of the disclaimers listed in this paragraph.

(11) An electric distribution company which is related as an affiliate or division of an electric generation supplier or transmission supplier (meaning any public utility that owns, operates, or controls facilities used for the transmission of electric energy) which serves any portion of this Commonwealth; and any electric generation supplier which is related as an affiliate or division of any electric distribution company or transmission supplier which serves any portion of this Commonwealth, shall insure that its employes function independently of other related companies.

Cross References

This section cited in 52 Pa. Code § 54.186 (relating to default service procurement and implementation plans); 52 Pa. Code § 111.8 (relating to agent identification; misrepresentation); and 52 Pa. Code § 111.14 (relating to notification regarding marketing or sales activity).

§ 54.123. Transfer of customers to default service.

The following standards apply to the transfer of a retail customer's electric generation service from an EGS to a default service provider within the meaning of § 54.182 (relating to definitions):

(1) An EGS may not transfer a retail customer from its electric generation service to the default service provider without the consent of the default service provider, except in the following situations:

(i) Upon Commission approval of the abandonment, suspension or revocation of an EGS license, consistent with §§ 54.41 and 54.42 (relating to transfer or abandonment of license; and license suspension; license revocation).

(ii) Upon nonpayment by a retail customer for services rendered by the EGS.

(iii) To correct an unauthorized or inadvertent switch of a retail customer's account from default service to an alternative EGS's service, consistent with § 57.177 (relating to customer dispute procedures).

(iv) Upon the normal expiration of contracts.

(2) An EGS may initiate transfers in the situations in paragraph (1) through standard electronic data interchange protocols.

(3) The Commission may impose a penalty for every retail customer transferred to default service in violation of this section, consistent with 66 Pa.C.S. §§ 3301—3316 (relating to violations and penalties).

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Source

The provisions of this § 54.123 adopted September 14, 2007, effective September 15, 2007, 37 Pa.B. 4996.

Cross References

This section cited in 52 Pa. Code § 54.186 (relating to default service procurement and implementation plans).

Subchapter F. REPORTING REQUIREMENTS FOR QUALITY OF SERVICE BENCHMARKS AND STANDARDS

Sec.
54.151. Purpose.
54.152. Definitions.
54.153. Reporting requirements
54.154. Customer surveys.
54.155. Informal complaints to the BCS.
54.156. Public information.

Authority

The provisions of this Subchapter F issued under the Public Utility Code, 66 Pa.C.S. § 501; and the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. § 2807(a) and (d), unless otherwise noted.

Source

The provisions of this Subchapter F adopted July 10, 1998, effective July 11, 1998, 28 Pa.B. 3283, unless otherwise noted.

§ 54.151. Purpose.

This subchapter establishes a means by which the Commission can develop uniform measurement and reporting to assure that the customer services of the EDCs are maintained, at a minimum, at the same level of quality under retail competition. This subchapter sets forth uniform measurements and reporting requirements for monitoring the level of the EDCs' customer service performance. This subchapter also establishes the effective dates of the reporting requirements.

§ 54.152. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

BCS—The Bureau of Consumer Services of the Commission.

Business office—A centralized service group which receives small commercial or residential billing inquiries, or both, and requests for service, whether or not equipped with an automated call distribution system.

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Busy-out rate—The number of calls to an EDC's call center or business office that received a busy signal divided by the number of calls that were received.

Call abandonment rate—The number of calls to an EDC's call center or business office that were abandoned divided by the total number of calls received at the EDC's telephone call center or business office.

Call center—A centralized facility established by a utility for transactions concerning installation and repair of service, billing and other inquiries between residential and small commercial customers and EDC representatives, but not including special purpose call centers established to respond to service emergencies and operating for a temporary period of time.

Code—The Public Utility Code, 66 Pa.C.S. §§ 101—3316.

Commission—The Pennsylvania Public Utility Commission.

Customer—A retail electric customer as defined in section 2803 of the code (relating to definitions).

EDC—Electric Distribution Company—The term defined in section 2803 of the code.

Informal consumer complaint—An appeal by a consumer to the BCS about a utility's proposed resolution of a dispute related to billing, service delivery, repairs and all other issues not related to requests for payment arrangements.

Informally verified infraction—An apparent misapplication of Commission regulations as determined by the BCS through its examination of information obtained as part of its review of informal consumer complaints and payment arrangement requests:

(i) The informal verification process implemented by the BCS notifies a utility of the information which forms the basis of an alleged infraction, affords the utility the opportunity to affirm or deny the accuracy of the information, and concludes with a BCS determination regarding the alleged infraction.

(ii) An informally verified infraction is not equivalent to a formal violation under section 3301 of the code (relating to civil penalties for violations) unless otherwise determined through applicable Commission procedures.

Infraction—A misapplication of a Commission regulation, particularly the standards and billing practices for residential service.

Infraction rate—The number of informally verified infractions per 1,000 residential customers.

Justified informal consumer complaint—A complaint where the BCS has determined that an EDC did not follow Commission procedures or regulations.

Justified informal consumer complaint rate—The number of justified informal, residential consumer complaints per 1,000 residential customers.

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Justified payment arrangement request—A payment arrangement request where an EDC did not follow Commission negotiation procedures or regulations.

Justified payment arrangement request rate—The number of justified payment arrangement requests from residential customers per 1,000 residential customers.

Payment arrangement request—A customer request for payment terms to the BCS.

Small business customer—A person, sole proprietorship, partnership, corporation, association or other business that receives electric service under a small commercial, small industrial or small business rate classification, and whose maximum registered peak load was less than 25 kW within the last 12 months.

Transaction survey—A survey targeted toward individuals that have had a recent interaction with an EDC. A transaction includes filing a complaint, inquiring about a bill, having a repair completed, installation of service or an appointment for a special meter reading.

§ 54.153. Reporting requirements.

(a) *Reporting requirements*.

(1) Unless otherwise specified in this subchapter, each EDC shall file its first report with the Commission on or before August 1, 1999. The August report shall contain data, reported by month, from the first 6 months of the calendar year, as well as a 6-month cumulative average.

(2) Each EDC shall file its second report on or before February 1, 2000. The February report shall contain data, reported by month, from the second 6 months of the year as well as 6-month cumulative average and a 12-month cumulative average for the preceding calendar year.

(3) Thereafter, the EDCs shall file reports annually with the Secretary of the Commission on or before February 1. Each report shall contain data, reported by month, as well as a 12-month cumulative average for the preceding calendar year. Each report shall include the name and telephone number of the utility contact person responsible for the report.

(b) *Records*. Each EDC shall take measures necessary and keep sufficient records to report the following data to the Commission:

(1) *Telephone access*.

(i) The percent of calls answered at each EDC's call center or business office, or both, within 30 seconds with the EDC representative ready to render assistance and to accept information necessary to process the call. An acknowledgment that the customer or applicant is waiting on the line does not constitute an answer. If the EDC reports data for more than one call center or business office, the EDC should also provide the combined percent of calls answered within 30 seconds for the EDC as a whole.

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(ii) The average busy-out rate for each call center business office, or both. If the EDC reports data for more than one call center or business office, the EDC should also provide the combined busy-out rate for the EDC as a whole.

(iii) The call abandonment rate for each call center or business office, or both. If the EDC reports data for more than one call center or business office, the EDC should also provide the combined call abandonment rate for the EDC as a whole.

(2) *Billing*.

(i) The number and percent of residential bills that the EDC failed to render once every billing period to residential ratepayers under § 56.11 (relating to billing frequency).

(ii) The number and percent of bills that the EDC failed to render once every billing period to small business customers.

(3) *Meter reading*.

(i) The number and percent of residential meters for which the company has failed to obtain an actual or ratepayer supplied reading within the past 6 months to verify the accuracy of estimated readings in accordance with § 56.12(4)(ii) (relating to meter reading; estimated billing; or ratepayer readings).

(ii) The number and percent of residential meters for which the company has failed to obtain an actual meter reading within the past 12 months to verify the accuracy of the readings, either estimated or ratepayer read in accordance with § 56.12(4)(iii).

(iii) The number and percent of residential remote meters for which it has failed to obtain an actual meter reading under the time frame in § 56.12(5)(ii).

(4) *Response to disputes*. The actual number of disputes as described in Chapter 56, Subchapter F (relating to disputes; termination disputes; informal and formal complaints) for which the company did not provide a response to the complaining party within 30 days of the initiation of the dispute under § 56.151(5) (relating to general rule).

(c) *Comparison of service quality.* Each EDC report to the Commission shall contain an analysis and comparison of the quality of service data in each performance area during the past 6 months with its previous service quality in these areas.

§ 54.154. Customer surveys.

(a) *Results of telephone transaction surveys*. Each EDC shall report to the Commission the results of telephone transaction surveys of customers who have had interactions with the EDC.

(1) The purpose of the transaction surveys is to assess the customer perception regarding the most recent interaction with the EDC. Survey questions

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shall measure access to the utility, employe courtesy, employe knowledge, promptness of EDC response or visit, timeliness of EDC response or visit and satisfaction with the handling of the interaction.

(2) The transaction survey questions shall specifically address the circumstances that generated the most recent transaction. Interaction categories include the following:

(i) Service installation.

(ii) Premise visit by company field personnel for an activity other than service installation.

(iii) Service interruption.

(iv) Billing balance inquiry or dispute.

(v) Request for discontinuance of service.

(vi) Application for service.

(vii) Other similar interactions.

(3) The EDCs shall carry out the transaction survey process using instruments and procedures that provide the Commission with uniform data that can be used to directly compare customer service performance among EDCs in this Commonwealth.

(4) A customer or consumer being surveyed shall be contacted within 30 days of the date that the interaction with the EDC took place.

(5) The sampling plan shall be designed so that the results are statistically valid within plus or minus 5%.

(b) *Commission approval*. The survey instrumentation, as well as procedures for case selection, sampling, conducting the survey, analyzing results and reporting to the Commission shall be subject to the review and approval of the Commission.

(c) *Timetable*.

(1) The first report on survey results shall be submitted to the Commission on or before October 1, 2000. The October report shall contain survey results, reported by month, from the first 6 months of the calendar year.

(2) The second report shall be submitted on or before April 1, 2001. The April report shall contain results, reported by month, from the second 6 months of the previous year as well as cumulative 12-month results.

(3) Thereafter, the EDC shall submit survey results annually, on or before April 1. Each annual report shall contain results reported by month as well as cumulative 12-month results.

§ 54.155. Informal complaints to the BCS.

(a) The BCS will review and analyze residential informal consumer complaints and payment arrangement requests filed with the Commission and will report the justified consumer complaint rate and the justified payment arrangement request rate to the Commission on an annual basis.

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(b) The BCS will report to the Commission the number of informally verified infractions of applicable statutes and regulations relating to the treatment of residential accounts by each EDC. The BCS will calculate and report to the Commission an ''infraction rate'' for each EDC.

§ 54.156. Public information.

The Commission will annually produce a summary report on the customer service performance of each EDC using the statistics collected as a result of these reporting requirements. The reports will be public information. The Commission will provide the reports to any interested party and post the reports on the Commission's Internet website.

Subchapter G. DEFAULT SERVICE

Sec.
54.181. Purpose.
54.182. Definitions.
54.183. Default service provider.
54.184. Default service provider obligations.
54.185. Default service programs and periods of service.
54.186. Default service procurement and implementation plans.
54.187. Default service rate design and the recovery of reasonable costs.
54.188. Commission review of default service programs and rates.
54.189. Default service customers.
54.190. Universal interest applicable to over collections and under collections resulting from reconciliation of automatic adjustment clauses costs and revenues related to electric default service.

Authority

The provisions of this Subchapter G issued and amended under the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. § 2807, unless otherwise noted.

Source

The provisions of this Subchapter G adopted September 14, 2007, effective September 15, 2007, 37 Pa.B. 4996, unless otherwise noted.

Cross References

This Subchapter G cited in 52 Pa. Code § 69.1802 (relating to purpose).

§ 54.181. Purpose.

This subchapter implements 66 Pa.C.S. § 2807(e) (relating to duties of electric distribution companies), pertaining to an EDC's obligation to serve retail customers at the conclusion of the restructuring transition period. This subchapter ensures that retail customers who do not choose an alternative EGS, or who contract for electric energy that is not delivered, have access to generation supply procured by a DSP pursuant to a Commission-approved competitive procurement plan. The EDC or other approved entity shall fully recover all reasonable costs for acting as a default service provider of electric generation supply to all retail customers in its certificated distribution territory.

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Source

The provisions of this § 54.181 amended August 10, 2012, effective August 11, 2012, 42 Pa.B. 5185. Immediately preceding text appears at serial page (330066).

§ 54.182. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

Alternative energy portfolio standards—A requirement that a certain percentage of electric energy sold to retail customers in this Commonwealth by EDCs and EGSs be derived from alternative energy sources, as defined in the Alternative Energy Portfolio Standards Act (73 P. S. §§ 1648.1—1648.8).

Bilateral contract—The term as defined in 66 Pa.C.S. § 2803 (relating to definitions).

Commission—The Pennsylvania Public Utility Commission.

Competitive bid solicitation process—A fair, transparent and nondiscriminatory process by which a default service provider awards contracts for electric generation supply to qualified suppliers who submit the lowest bids.

DSP—Default service provider—The term as defined in 66 Pa.C.S. § 2803.

Default service—Electric generation supply service provided pursuant to a default service program to a retail electric customer not receiving service from an EGS.

Default service implementation plan—The schedule of competitive bid solicitations and spot market energy purchases, technical requirements and related forms and agreements.

Default service procurement plan—The electric generation supply acquisition strategy a DSP will use in satisfying its default service obligations, including the manner of compliance with the alternative energy portfolio standards requirement.

Default service program—A filing submitted to the Commission by a DSP that identifies a procurement plan, an implementation plan, a rate design to recover all reasonable costs and other elements identified in § 54.185 (relating to default service programs and periods of service).

Default service rate—The rate billed to a default service customer resulting from compliance with a Commission-approved default service program.

EDC—Electric distribution company—The term has the same meaning as defined in 66 Pa.C.S. § 2803.

EGS—Electric generation supplier—The term has the same meaning as defined in 66 Pa.C.S. § 2803.

FERC—The Federal Energy Regulatory Commission.

Maximum registered peak load—The highest level of demand for a particular customer, based on the PJM Interconnection, LLC, ''Peak Load Contribution Standard,'' or its equivalent, and as may be further defined by the EDC tariff in a particular service territory.

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PTC—Price-to-compare—A line item that appears on a retail customer's monthly bill for default service. The PTC is equal to the sum of all unbundled generation and transmission related charges to a default service customer for that month of service.

RTO—Regional transmission organization—A FERC-approved regional transmission organization.

Retail customer or *retail electric customer*—These terms have the same meaning as defined in 66 Pa.C.S. § 2803.

Spot market energy purchase—The purchase of an electric generation supply product in a FERC-approved real time or day ahead energy market.

Source

The provisions of this § 54.182 amended August 10, 2012, effective August 11, 2012, 42 Pa.B. 5185. Immediately preceding text appears at serial pages (330067) to (330068).

Cross References

This section cited in 52 Pa. Code § 54.123 (relating to transfer of customers to default service).

§ 54.183. Default service provider.

(a) The DSP shall be the incumbent EDC in each certificated service territory, except as provided for under subsection (b).

(b) The DSP may be changed by one of the following processes:

(1) An EDC may petition the Commission to be relieved of the default service obligation.

(2) An EGS may petition the Commission to be assigned the default service role for a particular EDC service territory.

(3) The Commission may propose through its own motion that an EDC be relieved of the default service obligation.

(c) The Commission may reassign the default service obligation for the entire service territory, or for specific customer classes, to one or more alternative DSPs when it finds it to be necessary for the accommodation, safety and convenience of the public. A finding would include an evaluation of the incumbent EDC's operational and financial fitness to serve retail customers, and its ability to provide default service under reasonable rates and conditions. In these circumstances, the Commission will announce, through an order, a competitive process to determine the alternative DSP.

(d) When the Commission finds that an EDC should be relieved of the default service obligation, the competitive process for the replacement of the default service provider shall be as follows:

(1) An entity that wishes to be considered for the role of the alternative DSP shall file a petition under 66 Pa.C.S. § 2807(e)(3) (relating to duties of electric distribution companies).

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(2) Petitioners shall demonstrate their operational and financial fitness to serve and their ability to comply with Commission regulations, orders and applicable laws pertaining to public utility service.

(3) If no petitioner can meet this standard, the incumbent EDC shall be required to continue the provision of default service.

(4) If one or more petitioners meets the standard provided in paragraph (2), the Commission will approve the DSP best able to fulfill the obligation in a safe, cost-effective and efficient manner, consistent with 66 Pa.C.S. §§ 1103 and 1501 (relating to procedure to obtain certificates of public convenience; and character of service and facilities) and 2807(e).

(5) A petitioner approved to act as an alternative DSP shall comply with applicable provisions of the code, regulations and conditions imposed in approving the petition to act as an alternative DSP.

§ 54.184. Default service provider obligations.

(a) While an EDC collects either a competitive transition charge or an intangible transition charge or until 100% of an EDC's customers have electric choice, whichever is longer, an EDC as a default service provider shall be responsible for the reliable provision of default service to retail customers who are not receiving generation services from an alternative EGS within the certificated territory of the EDC that it serves or whose alternative EGS has failed to deliver electric energy.

(b) A DSP shall comply with the code and Chapter 1 (relating to rules of administrative practice and procedure) to the extent that the obligations are not modified by this subchapter or waived under § 5.43 (relating to petitions for issuance, amendment, repeal or waiver of regulations).

(c) Following the expiration of an EDC's obligation to provide electric generation supply service to retail customers at capped rates, if a customer contracts for electric generation supply service and the chosen EGS does not provide the service, or if a customer does not choose an alternative EGS, the default service provider shall provide electric generation supply service to that customer pursuant to a Commission-approved competitive procurement process that includes one or more of the following:

(1) Auctions.

(2) Requests for proposals.

(3) Bilateral agreements entered into at the sole discretion of the default service provider which shall be at prices that are either of the following:

(i) No greater than the cost of obtaining generation under comparable terms in the wholesale market, as determined by the Commission at the time of execution of the contract.

(ii) Consistent with a Commission-approved competition procurement process. Agreements between affiliated parties, including bilateral agreements between electric utilities and affiliated generators, shall be subject to review and approval of the Commission under 66 Pa.C.S. §§ 2101—2107

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(relating to relations with affiliated interests). The cost of obtaining generation from any affiliated interest may not be greater than the cost of obtaining generation under comparable terms in the wholesale market at the time of execution of the contract.

(d) A DSP shall continue the universal service and energy conservation program in effect in the EDC's certificated service territory or implement, subject to Commission approval, similar programs consistent with 66 Pa.C.S. §§ 2801—2815 (relating to Electricity Generation Customer Choice and Competition Act) and the amendments provided under the act of October 15, 2008 (P. L. 1592, No. 129) providing for energy efficiency and conservation programs. The Commission will determine the allocation of these responsibilities between an EDC and an alternative DSP when an EDC is relieved of its DSP obligation.

Source

The provisions of this § 54.184 amended August 10, 2012, effective August 11, 2012, 42 Pa.B. 5185. Immediately preceding text appears at serial page (330069).

Cross References

This section cited in 52 Pa. Code § 54.186 (relating to default service procurement and implementation plans).

§ 54.185. Default service programs and periods of service.

(a) A DSP shall file a default service program with the Commission's Secretary's Bureau no later than 12 months prior to the conclusion of the currently effective default service program or Commission-approved generation rate cap for that particular EDC service territory, unless the Commission authorizes another filing date. Thereafter, the DSP shall file its programs consistent with schedules identified by the Commission.

(b) The Commission will hold hearings as necessary on the proposed plan or amended plan. If the Commission fails to issue a final order on the plan or amended plan within 9 months of the date that the plan is filed, the plan or amended plan will be deemed to be approved and the default service provider may implement the plan or amended plan as filed. Costs incurred through an approved competitive procurement plan shall be deemed to be the least cost over time.

(c) Default service programs must comply with Commission regulations pertaining to documentary filings in Chapter 1 (relating to rules of administrative practice and procedure), except when modified by this subchapter. The DSP shall serve copies of the default service program on the Pennsylvania Office of Consumer Advocate, Pennsylvania Office of Small Business Advocate, the Commission's Office of Trial Staff, EGSs registered in the service territory and the RTO or other entity in whose control area the DSP is operating. Copies shall be provided upon request to other EGSs and shall be available at the DSP's public internet domain.

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(d) The first default service program shall be for a period of 2 to 3 years, or for a period necessary to comply with subsection (e)(4), unless another period is authorized by the Commission. Subsequent program terms will be determined by the Commission.

(e) A default service program must include the following elements:

(1) A procurement plan identifying the DSP's electric generation supply acquisition strategy for the period of service. The procurement plan should identify the means of satisfying the minimum portfolio requirements of the Alternative Energy Portfolio Standards Act (73 P. S. §§ 1648.1—1648.8) for the period of service.

(2) An implementation plan identifying the schedules and technical requirements of competitive bid solicitations and spot market energy purchases, consistent with § 54.186 (relating to default service procurement and implementation plans).

(3) A rate design plan recovering all reasonable costs of default service, including a schedule of rates, rules and conditions of default service in the form of proposed revisions to its tariff.

(4) Documentation that the program is consistent with the legal and technical requirements pertaining to the generation, sale and transmission of electricity of the RTO or other entity in whose control area the DSP is providing service. The default service procurement plan's period of service must align with the planning period of that RTO or other entity.

(5) Contingency plans to ensure the reliable provision of default service when a wholesale generation supplier fails to meet its contractual obligations.

(6) Copies of agreements or forms to be used in the procurement of electric generation supply for default service customers. This includes all documents used as part of the implementation plan, including supplier master agreements, request for proposal documents, credit documents and confidentiality agreements. When applicable, the default service provider shall use standardized forms and agreements that have been approved by the Commission.

(7) A schedule identifying generation contracts of greater than 2 years in effect between a DSP, when it is the incumbent EDC, and retail customers in that service territory. The schedule should identify the load size and end date of the contracts. The schedule shall only be provided to the Commission and will be treated as confidential.

(f) The Commission may, following notice and opportunity to be heard, direct that some or all DSPs file joint default service programs to acquire electric generation supply for all of their default service customers. In the absence of such a directive, some or all DSPs may jointly file default service programs or coordinate the scheduling of competitive bid solicitations to acquire electric generation for all of their default service customers. A multiservice territory procurement and implementation plan must comply with § 54.186.

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(g) DSPs shall include requests for waivers from the provisions of this subchapter in their default service program filings. For DSPs with less than 50,000 retail customers, the Commission will grant waivers to the extent necessary to reduce the regulatory, financial or technical burden on the DSP or to the extent otherwise in the public interest.

Source

The provisions of this § 54.185 amended August 10, 2012, effective August 11, 2012, 42 Pa.B. 5185. Immediately preceding text appears at serial pages (330069) to (330071).

Cross References

This section cited in 52 Pa. Code § 54.182 (relating to definitions); 52 Pa. Code § 54.186 (relating to default service procurement and implementation plans); 52 Pa. Code § 54.188 (relating to commission review of default services programs and rates); and 52 Pa. Code § 69.1803 (relating to definitions).

§ 54.186. Default service procurement and implementation plans.

(a) A DSP shall acquire electric generation supply at the least cost to customers over time for default service customers in a manner consistent with procurement and implementation plans approved by the Commission.

(b) A DSP's procurement plan must adhere to the following standards:

(1) The procurement plan shall be designed so that the electric power procured under § 54.184(c) (relating to default service provider obligations) includes a prudent mix of the following:

(i) Spot market purchases.

(ii) Short-term contracts.

(iii) Long-term purchase contracts, entered into as a result of auction, request for proposal or bilateral contract that is free of undue influence, duress or favoritism of greater than 4 years in length but not greater than 20 years. The default service provider shall have sole discretion to determine the source and fuel type. Long-term purchase contracts must be 25% or less of the DSP's projected default service load unless the Commission, after a hearing, determines for good cause that a greater portion of load is necessary to achieve least cost procurement.

(A) EDCs or Commission-approved alternative suppliers may offer large customers with a peak demand of 15 megawatts or greater at one meter at a location in its service territory any negotiated rate for service at all of the customers' locations within the service territory for any duration agreed upon by the EDC or alternative supplier and the large customer.

(B) The Commission may determine that a contract is required to be extended for longer than 20 years if the extension is necessary to ensure adequate and reliable service at least cost to customers over time.

(2) A prudent mix of contracts shall be designed to ensure:

(i) Adequate and reliable service.

(ii) The least cost to customers over time.

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(iii) Compliance with the requirements of paragraph (1).

(3) DSPs with loads of 50 megawatts or less shall evaluate the cost and benefits of joining with other DSPs or affiliates in contracting for electric supply.

(4) Procurement plans may include solicitations and contracts whose duration extends beyond the program period.

(5) Electric generation supply shall be acquired by competitive bid solicitation processes, spot market energy purchases, short- and long-term contracts, auctions, bilateral contracts or a combination of them.

(6) The DSP's supplier affiliate may participate in a competitive bid solicitation process used as part of the procurement plan subject to the following conditions:

(i) The DSP shall propose and implement protocols to ensure that its supplier affiliate does not receive an advantage in the solicitation and evaluation of competitive bids or other aspect of the implementation plan.

(ii) The competitive bid solicitation process shall comply with the codes of conduct promulgated by the Commission in § 54.122 (relating to code of conduct).

(c) A DSP's implementation plan must adhere to the following standards:

(1) A competitive bid solicitation process used as part of the default service implementation plan must provide, to the extent applicable and at the appropriate time, the following information to suppliers:

(i) A bidding schedule.

(ii) A definition and description of the power supply products on which potential suppliers shall bid.

(iii) Bid price formats.

(iv) A time period during which the power will need to be supplied for each power supply product.

(v) Bid submission instructions and format.

(vi) Price-determinative bid evaluation criteria.

(vii) Current load data for rate schedules or maximum registered peak load groupings, including the following:

(A) Hourly usage data.

(B) Number of retail customers.

(C) Capacity peak load contribution figures.

(D) Historical monthly retention figures.

(E) Estimated loss factors.

(F) Customer size distribution.

(2) The default service implementation plan must include fair and nondiscriminatory bidder qualification requirements, including financial and operational qualifications, or other reasonable assurances of a supplier of electric generation services' ability to perform.

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(3) A competitive bid solicitation process used as part of the implementation plan will be subject to monitoring by the Commission or an independent third party evaluator selected by the DSP in consultation with the Commission. A third party evaluator shall operate at the direction of the Commission. Commission staff and a third party evaluator involved in monitoring the procurement process shall have full access to all information pertaining to the competitive procurement process, either remotely or where the process is administered. A third party evaluator retained for purposes of monitoring the competitive procurement process shall be subject to confidentiality agreements identified in § 54.185(e)(6) (relating to default service programs and periods of service).

(4) The DSP or third party evaluator shall review and select winning bids procured through a competitive bid solicitation process in a nondiscriminatory manner based on the price determinative bid evaluation criteria set forth consistent with paragraph (1)(vi).

(5) The bids submitted by a supplier in response to a competitive bid solicitation process shall be treated as confidential pursuant to the confidentiality agreement approved by the Commission under § 54.185(e)(6). The DSP, the Commission and a third party involved in the administration, review or monitoring of the bid solicitation process shall be subject to this confidentiality provision.

(d) The DSP may petition for modifications to the approved procurement and implementation plans when material changes in wholesale energy markets occur to ensure the acquisition of sufficient supply at the least cost to customers over time. The DSP shall monitor changes in wholesale energy markets to ensure that its procurement plan continues to reflect the incurrence of reasonable costs, consistent with 66 Pa.C.S. § 2807(e)(3.1)—(3.4) (relating to duties of electric distribution companies).

(e) At the time the Commission evaluates the plan and prior to its approval, in determining if the DSP's plan obtains generation supply at the least cost, the Commission will consider the DSP's obligation to provide adequate and reliable service to customers and that the DSP has obtained a prudent mix of contracts to obtain least cost on a long-term, short-term and spot market basis. The Commission will make specific findings which include the following:

(1) The DSP's plan includes prudent steps necessary to negotiate favorable generation supply contracts through a competitive procurement process.

(2) The DSP's plan includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis.

(3) Neither the DSP nor its affiliated interest has withheld from the market any generation supply in a manner that violates Federal law.

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The provisions of this § 54.186 amended August 10, 2012, effective August 11, 2012, 42 Pa.B. 5185. Immediately preceding text appears at serial pages (330071) to (330072) and (340965).

Cross References

This section cited in 52 Pa. Code § 51.12 (relating to definitions); 52 Pa. Code § 54.185 (relating to default service programs and periods of service); and 52 Pa. Code § 54.188 (relating to commission review of default service programs and rates).

§ 54.187. Default service rate design and the recovery of reasonable costs.

(a) The Commission may modify contracts or disallow costs when after a hearing the party seeking recovery of the costs of a procurement plan is found to be at fault for either of the following:

(1) Not complying with the Commission-approved procurement plan.

(2) The commission of fraud, collusion or market manipulation with regard to these contracts.

(b) The costs incurred for providing default service shall be recovered on a full and current basis through a reconcilable automatic adjustment clause under 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), all reasonable costs incurred under 66 Pa.C.S. § 2807(e)(3.9) (relating to duties of electric distribution companies) and a Commission-approved competitive procurement plan. The use of an automatic adjustment clause shall be subject to audit and annual review, consistent with 66 Pa.C.S. § 1307(d) and (e).

(c) Except for rates available consistent with § 54.190 (relating to universal interest applicable to over collections and under collections resulting from reconciliation of automatic adjustment clauses costs and revenues related to electric default service), a default service customer shall be offered a single rate option, which shall be identified as the PTC and displayed as a separate line item on a customer's monthly bill.

(d) The rates charged for default service may not decline with the increase in kilowatt hours of electricity used by a default service customer in a billing period.

(e) The PTC shall be designed to recover all default service costs, including generation, transmission and other default service cost elements, incurred in serving the average member of a customer class. An EDC's default service costs may not be recovered through the distribution rate. Costs currently recovered through the distribution rate, which are reallocated to the default service rate, may not be recovered through the distribution rate. The distribution rate shall be reduced to reflect costs reallocated to the default service rate.

(f) A DSP shall use an automatic energy adjustment clause, consistent with 66 Pa.C.S. § 1307 and Chapter 75 (relating to alternative energy portfolio standards), to recover all reasonable costs incurred through compliance with the Alternative Energy Portfolio Standards Act (73 P. S. §§ 1648.1—1648.8). The use of an automatic adjustment clause shall be subject to audit and annual review,

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consistent with 66 Pa.C.S. § 1307(d) and (e), regarding fuel cost adjustment audits and automatic adjustment reports and proceedings.

(g) The default service rate schedule must include rates that correspond to demand side response and demand side management programs, as defined in section 2 of the Alternative Energy Portfolio Standards Act (73 P. S. § 1648.2), when the Commission mandates these rates pursuant to its authority under 66 Pa.C.S. Chapter 1 (relating to general provisions).

(h) Default service rates may not be adjusted more frequently than on a quarterly basis for all customer classes with a maximum registered peak load up to 25 kW, to ensure the recovery of costs reasonably incurred in acquiring electricity at the least cost to customers over time. DSPs may propose alternative divisions of customers by maximum registered peak load to preserve existing customer classes.

(i) Default service rates shall be adjusted on a quarterly basis, or more frequently, for all customer classes with a maximum registered peak load of 25 kW to 500 kW, to ensure the recovery of costs reasonably incurred in acquiring electricity at the least cost to customers over time. DSPs may propose alternative divisions of customers by maximum registered peak load to preserve existing customer classes.

(j) Default service rates shall be adjusted on a monthly basis, or more frequently, for all customer classes with a registered peak load of equal to or greater than 500 kW to ensure the recovery of costs reasonably incurred in acquiring electricity at the least cost to customers over time. DSPs may propose alternative divisions of customers by registered peak load to preserve existing customer classes.

(k) When a supplier fails to deliver electric generation supply to a DSP, the DSP shall be responsible for acquiring replacement electric generation supply consistent with its Commission-approved contingency plan. When necessary to procure electric generation supply before the implementation of a contingency plan, a DSP shall acquire supply at the least cost to customers over time and fully recover all reasonable costs associated with this activity that are not otherwise recovered through its contract terms with the default supplier. The DSP shall follow acquisition strategies that reflect the incurrence of reasonable costs, consistent with 66 Pa.C.S. § 2807, when selecting from the various options available in these energy markets.

Source

The provisions of this § 54.187 amended August 10, 2012, effective August 11, 2012, 42 Pa.B. 5185; amended December 18, 2015, effective December 19, 2015, 45 Pa.B. 7161. Immediately preceding text appears at serial pages (362997) to (362999).

Cross References

This section cited in 52 Pa. Code § 54.188 (relating to commission review of default service programs and rates); 52 Pa. Code § 54.190 (relating to universal interest applicable to over collections and under collections resulting from reconciliation of automatic adjustment clauses costs and revenues related to electric default service); and 52 Pa. Code § 75.67 (relating to alternative energy cost-recovery).

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§ 54.188. Commission review of default service programs and rates.

(a) A DSP shall file a plan or amended plan for competitive procurement with the Commission and obtain Commission approval of the plan or amended plan considering the standards in 66 Pa.C.S. § 2807(e)(3.1), (3.2), (3.3) and (3.4) (relating to duties of electric distribution companies) before the competitive process is implemented. The Commission will hold hearings as necessary on the proposed plan or amended plan. A default service program will initially be referred to the Office of Administrative Law Judge for further proceedings as may be required.

(b) If the Commission fails to issue a final order on the plan or amended plan within 9 months of the date the plan or amended plan is filed, the plan or amended plan will be deemed approved and the DSP may implement the plan or amended plan as filed. Costs incurred through an approved competitive procurement plan will be deemed to be the least cost over time as required under 66 Pa.C.S. § 2807(e)(3.4)(ii).

(c) Upon entry of the Commission's final order, a DSP shall acquire generation supply for the period of service in a manner consistent with the terms of the approved procurement and implementation plans and consistent with the standards identified in § 54.186 (relating to default service procurement and implementation plans).

(d) The Commission may initiate an investigation regarding implementation of the DSP's default service program and, at the conclusion of the investigation, order remedies as may be lawful and appropriate. The Commission will not deny the DSP the recovery of its reasonable costs for purchases made pursuant to an approved competitive procurement process unless the DSP concealed or misled the Commission regarding its adherence to the program, or otherwise violated the provisions of this subchapter or the code. Except as provided under the Alternative Energy Portfolio Standards Act (73 P. S. §§ 1648.1—1648.8), the Commission may not order a DSP to procure power from a specific generation supplier, from a specific generation fuel type or from new generation only. At the time the Commission evaluates the plan and prior to approval, the Commission will consider the default service provider's obligation to provide adequate and reliable service to customers and that the DSP has obtained a prudent mix of contracts to obtain least cost on a long-term, short-term and spot market basis. The Commission will make specific findings which include:

(1) The DSP's plan includes prudent steps necessary to negotiate favorable generation supply contracts through a competitive procurement process.

(2) The DSP's plan includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis.

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(3) Neither the DSP nor its affiliated interest has withheld from the market any generation supply in a manner that violates Federal law.

(e) A DSP shall adhere to the following procedures in obtaining approval of default service rates and providing notice to default service customers:

(1) A DSP shall provide all customers notice of the filing of a default service program in a similar manner as found in § 53.68 (relating to notice requirements).

(2) A DSP shall provide all customers notice of the initial default service rates and terms and conditions of service 60 days before their effective date, or 30 days after bidding has concluded, whichever is sooner, unless another time period is approved by the Commission. The DSP shall provide written notice to the named parties identified in § 54.185(b) (relating to default service programs and periods of service) containing an explanation of the methodology used to calculate the price for electric service.

(3) After the initial steps of a default service procurement and implementation plan are completed, the DSP shall file with the Commission tariff supplements designed to reflect, for each customer class, the rates to be charged for default service. The tariff supplements shall be accompanied by supporting documentation adequate to demonstrate adherence to the procurement plan approved by the Commission, the procurement plan results and the translation of those results into customer rates.

(4) A customer or party identified in § 54.185(b) may file exceptions to the initial default service tariffs within 20 days of the date the tariffs are filed with the Commission. The exceptions shall be limited to whether the DSP properly implemented the procurement plan approved by the Commission and accurately calculated the rates. The Commission will resolve filed exceptions by order. The Commission may allow the default rates to become effective pending the resolution of those exceptions.

(f) A DSP may not submit tariff supplements more frequently than on a quarterly basis, consistent with § 54.187(h) and (i) (relating to default service rate design and recovery of reasonable costs), to revise default service rates to ensure the recovery of costs reasonably incurred in acquiring electricity at the least cost to customers over time. The DSP shall provide written notice to the named parties identified in § 54.185(b) of the proposed rates at the time of the tariff filings. The tariff supplements shall be posted to the DSP's web site at the time they are filed with the Commission. A customer or the parties identified in § 54.185(b) may file exceptions to the default service tariffs within 20 days of the date the tariffs are filed with the Commission. The exceptions shall be limited to whether the DSP has properly implemented the procurement plan approved by the Commission and accurately calculated the rates. The DSP shall post the revised PTC for each customer class within 1 business day of its effective date to its web site to enable customers to make an informed decision about electric generation supply options.

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(g) If a customer chooses an alternative supplier and subsequently desires to return to the local distribution company for generation service, the local distribution company shall treat that customer exactly as it would any new applicant for energy service.

(h) A DSP may, in its sole discretion, offer large customers with a peak demand of 15 megawatts or greater at one meter location in its service territory any negotiated rate for service at all of the customers' locations within the service territory for any duration agreed upon by the DSP and the customer.

(1) Contract rates shall be subject to Commission review to ensure all costs are borne by the parties to the contract and no one else.

(2) If no costs related to the rates are borne by other customers, the Commission will approve the contract within 90 days of its filing at the Commission. If the Commission does not approve the contract within the 90-day period, it shall be deemed approved.

(i) The DSP shall offer residential and small business customers a generation supply service rate that may not change more frequently than on a quarterly basis. Default service rates shall be reviewed by the Commission to ensure that the costs of providing service to each customer class are not subsidized by any other class.

Source

The provisions of this § 54.188 amended August 10, 2012, effective August 11, 2012, 42 Pa.B. 5185. Immediately preceding text appears at serial pages (340966) and (346875) to (346876).

§ 54.189. Default service customers.

(a) At the conclusion of an EDC's Commission approved generation rate cap, retail customers who are not receiving generation service from an EGS shall be assigned to the Commission-approved DSP in that service territory.

(b) A DSP shall accept applications for default service from new retail customers when the customers comply with Commission regulations pertaining to applications for service, including those in Chapter 56 (relating to standards and billing practices for residential utility service) and accept all retail customers assigned to its default service who switch from an EGS.

(c) A DSP shall treat a customer who leaves an EGS as it would a new applicant for default service.

(d) A default service customer may choose to receive its generation service from an EGS at any time, if the customer complies with all Commission regulations pertaining to changing generation service providers in Chapter 57 (relating to electric service).

(e) A DSP may not charge a fee to a retail customer for changing its generation service provider in a manner consistent with Commission regulations.

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§ 54.190. Universal interest applicable to over collections and under collections resulting from reconciliation of automatic adjustment clauses costs and revenues related to electric default service.

(a) *General rule.* This section applies to automatic adjustment clauses related to electric default service filed with the Commission by a DSP under § 54.187(b) (relating to default service rate design and the recovery of reasonable costs).

(b) *Definitions.* The following words and terms, when used in this section, have the following meaning, unless the context clearly indicates otherwise:

Costs—The total amount of expenses, or class of expenses incurred, which is the basis of the automatic adjustment clause.

Over collection—The amount equal to revenues received under an automatic adjustment clause which exceeds the amount of costs incurred.

Revenue—The total proceeds received under the automatic adjustment clause.

Under collection—The amount equal to costs incurred under an automatic adjustment clause which exceeds the amount of revenues received.

(c) *Interest collectible on over collections and under collections.* When revenues exceed costs, the over collections shall be refunded to customers with interest. When costs exceed revenues, the under collections shall be collected from customers with interest. Interest on over collections and under collections shall be computed at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the *Wall Street Journal*. Interest shall be computed monthly from the month the over collection or under collection occurs to the effective month that the over collection is refunded or the under collection is collected.

Source

The provisions of this § 54.190 adopted December 18, 2015, effective December 19, 2015, 45 Pa.B. 7161.

Cross References

This section cited in 52 Pa. Code § 54.187 (relating to default service rate design and the recovery of reasonable costs).

Subchapter H. RETAIL ELECTRICITY CHOICE SALES ACTIVITY REPORTS

Sec.
54.201. Purpose.
54.202. Definitions.
54.203. Reporting requirements.
54.204. Public information.

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Authority

The provisions of this Subchapter H issued under 66 Pa.C.S. §§ 501, 504 and 2801 and 2812, unless otherwise noted.

Source

The provisions of this Subchapter H adopted May 29, 2009, effective May 30, 2009, 39 Pa.B. 2707.

§ 54.201. Purpose.

This subchapter establishes reporting requirements applicable to EDCs and active EGSs and requires the reporting of information related to retail electric generation sales activity. The Commission will use this information to fulfill its duty to monitor the Commonwealth's retail electric generation market and to police and arrest instances of market power abuse and discriminatory conduct. (See 66 Pa.C.S. § 2811 (relating to market power remediation).) The information shall be used to conduct milestone reviews of the development of the retail market for the supply of electricity. (See 66 Pa.C.S. § 2804(12) (relating to standards for restructuring of electric industry).)

§ 54.202. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

Active EGS—An EGS that is licensed to provide retail electric generation service and is providing that service to one or more customers.

CEEP—The Bureau of Conservation, Economics and Energy Planning or a successor Commission Bureau assigned the task of monitoring the retail electric generation market for anti-competitive behavior and abuse of market power.

Capped electric generation rates—Electric Generation Rates established through restructuring plans approved by the Commission under 66 Pa.C.S. Chapter 28 (relating to the Electricity Generation Customer Choice and Competition Act).

EDC—electric distribution company—The term as defined in 66 Pa.C.S. § 2803 (relating to definitions).

EGS—electric generation supplier—The term as defined in 66 Pa.C.S. § 2803.

Flat Rate Customer Account—A customer account that is charged a fixed cents per kwh rate that changes no more frequently than monthly, excluding seasonal rates.

Green power customer account—A retail customer account incorporating electric power supply that has greater than required renewable content as specified in section 3 of the Alternative Energy Portfolio Standards Act (73 P.S § 1648.3).

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Hybrid rate customer account—A retail customer account that is charged via an electric generation pricing arrangement that incorporates hourly and block rates.

kW—Kilowatts.

kWh—Kilowatthour.

Large nonresidential customers—Commercial and industrial customers with annual usage greater than 2,409,001 kWh.

Medium nonresidential customers—Commercial and industrial customers with annual usage ranging from 120,451 up to and including 2,409,000 kWh.

MWh—Megawatthours.

Small nonresidential customers—Commercial and industrial customers with annual usage ranging from 0 up to and including 120,450 kWh.

TOU customer account—Time-of-use customer account—A retail customer account that is charged a time of use rate.

Time-of-use rate—TOU—A rate that reflects the costs of serving customers during different time periods, including off-peak and on-peak periods, but not as frequently as each hour.

§ 54.203. Reporting requirements.

(a) Reporting requirements.

(1) An EDC or an active EGS shall report the information regarding retail sales of electric generation in accordance with this subchapter.

(2) An EDC shall report retail sales activity in its service territory. The EDC shall report information by customer class for residential, commercial, and industrial customers. An EDC with capped electric generation rates shall report information in the aggregate for residential customers, and by rate schedule and in the aggregate for commercial and industrial customers. An EDC that does not have capped electric generation rates shall report information for residential, commercial and industrial customers by rate class as defined by the default service program approved by the Commission. The EDC shall report the following information:

(i) Total number of customer accounts served by EGSs.

(ii) Total number of customer accounts being served by EGSs and the EDC.

(iii) MWh sales of EGSs.

(iv) MWh sales of EGSs and the EDC.

(v) EGSs serving customer accounts by class.

(vi) Total number of EDC TOU customer accounts served by EGSs.

(vii) Total number of EDC TOU customer accounts served by EGSs and the EDC.

(viii) MWh sales of EGSs to EDC TOU customer accounts.

(ix) MWh sales of EGSs and the EDC to EDC TOU customer accounts.

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(x) Total number of EDC hourly/real time price customer accounts served by EGSs.

(xi) Total number of hourly/real time price customer accounts served by EGSs and the EDC.

(xii) MWh sales by EGSs to EDC hourly/real time priced customer accounts.

(xiii) MWh sales by EGSs and the EDC to EDC hourly/real time priced customer accounts.

(3) An EDC shall report retail sales activity of EGSs operating in its service territory. An EDC shall report the following information for an EGS providing service in the EDC's service territory, marking the information as confidential:

(i) Identity of the EGS.

(ii) Number of customer accounts served by the EGS by customer class for residential, commercial and industrial customers.

(iii) Sales in MWh of customer accounts served by the EGS by customer class for residential, commercial and industrial customers.

(4) An active EGS shall report retail sales activity on a Statewide basis. The EGS shall report the following information by customer class for residential, small nonresidential customers, medium nonresidential customers and large nonresidential customers, marking the information as confidential:

(i) Number of customer accounts.

(ii) Number of flat rate customer accounts.

(iii) Number of seasonal rate customer accounts.

(iv) Number of TOU customer accounts.

(v) Number of hybrid rate customer accounts.

(vi) Number of fixed term contract customer accounts by length of the original primary contract, specifying the length in number of years.

(vii) Number of green power customer accounts.

(viii) Number of mandatory curtailable customer accounts.

(ix) Number of voluntary curtailable customer accounts.

(x) Number of customer accounts based on billing methods.

(xi) Number of hourly/real time pricing customer accounts.

(5) An EDC shall file quarterly sales activity reports with the Commission's Secretary and CEEP. A quarterly report shall be filed no later than 30 days after the end of the previous quarter.

(6) An active EGS shall file an annual sales activity report for the previous calendar year with the Commission's Secretary and CEEP on or before April 30 of each year.

(b) *Report forms.*

(1) The Commission shall provide separate report forms for EDC and EGS use. An EDC or an active EGS shall use the applicable report form.

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(2) Report forms shall be made available in both paper and electronic format. Report forms in electronic format may be downloaded at the Commission's web site, or will be provided in paper format upon request to the Commission's forms officer.

(3) An EDC or active EGS shall file an original of a completed paper report form with the Commission's Secretary and the Bureau of Technical Utiltiy Services. When the report form is filed electronically, one paper copy of the report form shall be filed with the Commission's Secretary no later than 15 days after the report is due when the report form exceeds 250 pages.

(c) *Compliance monitoring and enforcement*. CEEP is the Commission bureau responsible for retaining reports filed under this subchapter, and for monitoring and enforcing compliance with this subchapter.

Authority

The provisions of this § 54.203 amended under the Public Utility Code, 66 Pa.C.S. §§ 501, 504, 523, 1301, 1501 and 1504.

Source

The provisions of this § 54.203 amended January 10, 2014, effective January 11, 2014, 44 Pa.B. 249. Immediately preceding text appears at serial pages (363003) to (363005).

§ 54.204. Public information.

The Commission will make available to the public on an aggregated basis information contained in sales activity reports that does not disclose individual EGS market shares.

[Next page is 55-1.]

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CGC Exhibit 4

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set XXIX Data Requests of the
Office of Consumer Advocate (OCA)
Dated December 29, 2025
Docket No. R-2025-3057164

OCA XXIX-1

Please expand on cash flow as it relates to compensation to customer-generators for excess generation.

a. How does PPL pay for the excess generation in the annual cash-out? That is, from where is the cash derived? Does PPL use working capital to do this or is this cash-out funded by the default service plan (DSP) suppliers from the applicable DSP?
b. Does "backing out" net metering quantity in GSC-1 energy procurement make under-collection of revenue in a DSP cycle more likely? If DSP suppliers are funding the annual cash-out (Question 1) and the quantity in GSC-1 energy procurement reflects backed out net metering (Answer to OCA XXVII-4), will DSP suppliers need to increase their rates to ensure they are made financially whole?
c. Or, when PPL recovers this under-collection through an E-Factor reconciling item in a subsequent DSP cycle, does this revenue go back to DSP suppliers (if they are funding the cash-out per Question 1)?

PPL Electric Response

a. The actual expense incurred associated with cashing out net metering customers for excess generation is incurred by PPL Electric and included in the reconciliation calculation of the Transmission Service Charge (TSC) for the respective customer classes and the reconciliation calculation of the Generation Supply Charge-1 (GSC-1) charge for Residential and Small C&I customers and the Generation Supply Charge-2 (GSC-2) for Large C&I customers. The reconciliation amount is then included in the subsequent TSC, GSC-1, and GSC-2 rate filings in the Net Over(Under) Collection Amount value.

The TSC, GSC-1, and GSC-2 are charged to only default service customers.

Because these are rider-related expenses, they are not included in the Company's cash working capital calculation in this instant rate case.

From a strictly cash perspective, PPL Electric pays the customer-generator accounts for the expense on its books and later recovers the cash from default service customers through the ratemaking method described above. PPL Electric recovers the cash when customers pay their monthly bills.

b. To clarify, Default Service Suppliers are not funding the net metering cash out. This expense is incurred by PPL Electric and recovered by PPL Electric through a portion of dollars received by PPL Electric through the TSC, GSC-1, and GSC-2 rates.

Assuming the question is referring to the Company's practice of removing an estimated amount of net metering generation from the default service load used to calculate the GSC-1 rate as described in the response to JSA V-9, the Company does not believe that doing so makes an under collection more likely. Rather, the Company makes this adjustment in an effort to make the forecasted default service load used in the rate calculation more reflective of the actual default service load that the Company will experience during the period to minimize the amount of the reconciliation over/under amount. That reconciliation over/under amount is included in subsequent GSC-1 rate filings.

c. See the responses to Part A and B.

CGC Exhibit 4

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set XXIX Data Requests of the
Office of Consumer Advocate (OCA)
Dated December 29, 2025
Docket No. R-2025-3057164

OCA XXIX-2	Is the cash flow process outlined in Question 1 similar for both GSC-1 and GSC-2?
PPL Electric Response	Yes.

CGC Exhibit 5

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-12

Refer to Direct Testimony of Andrew Castanaro, PPL St. No. 15, at 6:12-14, which states "Additionally, the current classification results in non-net metering Small C&I default service customers disproportionately subsidizing the annual cash-outs of customer generators that are, effectively, merchant generators."

a. Provide all Documents, workpapers, and analyses PPL has performed, in their original format with formulas intact, that quantify the "subsidization" of customer-generators.
b. If PPL has not performed any analyses on this issue, identify, explain and describe the source of the support and basis for this statement.

PPL Electric Response

a. See response to CGC DR I-4, PPL Electric St. No. 15, PPL Electric Exhibits AC-1 through AC-3, and OCA I-1 CONFIDENTIAL Attachments 14-16.
b. Not applicable.

CGC Exhibit 5

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-19	If PPL does not utilize excess electricity it purchases from customer-generators as part of its default service supply, please explain in detail what PPL does with this supply? Provide all Documents that support, are utilized and/or relied upon in your answer.
PPL Electric Response	PPL Electric does not purchase excess electricity from customer-generators. Rather, the Company provides bill credits and monetary payouts for the excess generation at the end of the PJM planning year in accordance with applicable statutes and regulations. The customer-generator's excess generation reduces the aggregate load, thereby lowering the procurement for the Company's load-following contracts in its default service procurement.

CGC Exhibit 5

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated November 12, 2025
Docket No. R-2025-3057164

JSA II-20	If PPL sells excess electricity from customer-generators on the PJM market, identify, describe and explain in detail how it recovers any difference between what it pays for this electricity and what it is paid for this electricity on the market. Provide all Documents that support, are utilized and/or relied upon in your answer.
PPL Electric Response	PPL Electric does not sell excess electricity from customer-generators on the PJM market.

CGC Exhibit 6

WITNESS: Gregory Olsen
Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set IX Data Requests and Requests for the
Production of Documents of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated February 19, 2026
Docket No. R-2025-3057164

JSA IX-1	Identify, explain and describe in detail why PPL witness Andrew Castanaro in his Rejoinder Testimony, PPL Statement No. 15-RJ, page 14, continues to claim that the 29.8% capacity factor is reasonable and appropriate. Provide all Documents that support and/or provide the basis for your answer.
PPL Electric Response	The Company was modeling the maximum kWh output of a no-load solar generator to identify the extent of the potential impact to the Small C&I PTC. The 29.8% is within a reasonable capacity factor range. Customers have self-reported capacity factors as high as 33.37% as reported in JSA IX-5 Confidential Attachment 1on the "Customer Reported CF" sheet which supports the possibility of systems reaching a capacity factor of 29.8%. Additionally, 346 of the 371 (93.26%) self-reported capacity factors submitted by customers exceed 17.3%, with an average of 20.90%. PPL Electric has offered testimony using JSA's lower recommended capacity factor of 17.3%, which is representative of the lower capacity factor projects in PPL Electric service territory. This approach demonstrates that even if a low capacity factor is assumed, there is still an increase in the Small Commercial and Industrial customer's price-to-compare ("PTC").

CGC Exhibit 6

WITNESS: Andrew Castanaro

PPL Electric Utilities Corporation
Response to the Set IX Data Requests and Requests for the
Production of Documents of the
Solar Energy Industries Association and the Coalition for Community Solar Access, collectively "Joint Solar Advocates" (JSA)
Dated February 19, 2026
Docket No. R-2025-3057164

JSA IX-6 Please refer to workpaper OCA I-1 Attachment 14 Castanaro CORRECTED MODIFIED ("Alternative analysis")

i. Provide all Documents including, without limitation, the workpaper that was used to calculate the Total Projected kWh Bank by year found on tab "Cashout Values". This request is for all workpapers and calculations starting from the original set of individual projects that were included in the analysis and should include any adjustments or modifications the Company used. It should clearly reproduce the exact values (e.g., 172,008,146 kWh in 2026) found in this tab.

ii. Provide all calculations related to the updated figures using the 17.3% capacity factor, including all needed to trace the generation estimate from the original list of projects to the final number found in this workpaper. Provide all Documents that support and/or provide the basis for your answer.

iii. Identify, explain, describe and confirm that, with respect to tab "Mar. '26 Reconciliation", that the values in the "Energy Revenues Available (excluding GRT and MFC) (Schedule 2, Line 1, Column M)" row represents the payments from DSP customers for the energy they consumed on their premise, and that this value is calculated using the customer's metered consumption data. Provide all Documents that support and/or provide the basis for your answer.

iv. Does witness Castanaro agree that, assuming de minimis self-consumption from FTM DG systems, the kWh of usage from default service customers is not affected by generation from FTM DG resources?

Explain your answer and provide all Documents that support and/or provide the basis for your answer.

v. Does witness Castanaro agree that the amount of metered consumption from all default service customers would be the same regardless of whether the supply is from the DSP provider or from FTM DG systems? Explain your answer and provide all Documents that support and/or provide the basis for your answer.

vi. Identify, explain, describe and confirm that, in the Alternative analysis, Mr. Castanaro reduced both the energy revenues available (see e.g., line 1 of tab Mar.‘26 Reconciliation) and the Energy Procurement expenses (see e.g., line 2 of tab Mar.‘26 Reconciliation). Explain your answer and provide all Documents that support and/or provide the basis for your answer.

vii. Identify, explain, describe and confirm why, in the Alternative analysis, Witness Castanaro assumes that energy revenues from default service customers in a given calendar year will be reduced by FTM DG generation. Explain your answer in detail including, without limitation, the mechanism that would cause this to occur. Provide all Documents that support and/or provide the basis for your answer.

viii. Identify, explain, describe and confirm that the E-Factor calculations in the various “SCI PTC” tabs use as a denominator the SCI sales less projected FTM excess generation, as indicated by the formula referencing corresponding values from tab “SCI GSC1” rows 20-23, and not SCI sales.

ix. Identify, explain, describe why the E-Factor calculations in the various “SCI PTC” tabs use SCI sales less projected FTM excess generation as a denominator instead of the actual SCI sales volume?

x. Identify, explain, describe and confirm that by dividing the amount of under-recovery by a smaller kWh value,

the resulting E-Factor Rate is higher than it would be if the SCI sales value were used.

xi. Ref. tabs “Mar. ‘25 TSC Rate” and “Mar. ‘25 TSC Recon”

a. Identify, describe and explain the method that is used to reconcile the TSC rate with respect to FTM NEM expenses. Provide all Documents that support and/or provide the basis for your answer.

b. Identify, describe and explain the values in line “Actual Net Metering Expenses” on tab Mar. '25 TSC Recon and of the values in line “Net Metering Expenses (Schedule B)” on tab “Mar. '25 TSC Rate”. Provide all Documents that support and/or provide the basis for your answer.

c. If these values were from the same computation period, would they be equal to each other? Provide all Documents that support and/or provide the basis for your answer.

d. Explain in detail why did the Company not include any TSC rate reconciliation in this workpaper, despite the TSC rate being a component of the PTC that directly impacts total excess generation payouts. Provide all Documents that support and/or provide the basis for your answer.

e. Identify, describe and explain what happens, under the terms of the Company’s DSP Supplier contracts, in the event that the total amount of excess generation from GSC-1 FTM DG systems exceeds the total quantity of consumption from GSC-1 customers. Provide all Documents that support and/or provide the basis for your answer.

PPL Electric Response

i. See response to JSA IX-5 iii.

ii. See response to JSA IX-5 iii.
iii. Confirmed, as modeled, the values represented in the Energy Revenues Available are the forecasted payments from the aggregated customer metered data.
iv. PPL Electric generally agrees that FTM DG systems do not impact individual customers' metered electricity consumption. However, the Company's aggregated kWh customer metered data is impacted by the FTM DG. The Default Service load, as defined by the Supplier Master Agreement, is the net total default service customer sales less excess generation from net metering generation. From an ISO settlement and energy procurement perspective, the sum of hourly customer metered load and excess generation is used to determine the amount of load assigned to default service suppliers. Accordingly, FTM DG generation affects default service energy procurement requirements. See the definition of Default Service Load ("DS Load") in Article 1 Definitions on page 10 of JSA IX-6 Attachment 1.
v. PPL Electric agrees that the default service metered consumption would not be impacted by FTM DG. See response to part iv.
vi. As modeled, the energy revenues available and energy procurement expenses are both reduced by the projected FTM DG generation for the given year in the alternative analysis. This modeling was done in an effort to consider JSA's suggestion that a reduction in energy procurement expense would be significant enough to offset the increase in net metering expense that would be recovered through the GSC-1 rate by the Company. As shown by the alternative analysis, the hypothetical reduction in energy procurement expense does not offset the increased net metering expense, resulting in an increased GSC-1 rate.

In practice, the Company does not currently reduce the forecasted Default Service load in its GSC-1 rate filing by its forecasted MG FTM DG generation. While this means that the Company is likely including a larger procurement expense in its rate calculation than it will actually incur, any over collection between forecasted and actual procurement expense is trued-up in the rate

reconciliation filing and recovered through the e-factor in the subsequent rate filing.

vii. See response to part vi.

viii. Confirmed. The Company modeled the denominator of the E-factor rate as the default service forecasted load less the FTM excess generation.

ix. The denominator is reduced by the excess generation because the E-Factor is recovered over default service load obligation.

x. Confirmed that dividing the under recovery by a smaller amount would result in a higher E-Factor rate. A lower default service load obligation reduces the ability to spread recovery of the under-collection, contributing to the higher E-Factor rate for the remaining default service load.

xi. a. The TSC is reconciled annually through a filing that compares actual TSC revenue collected from default service customers against actual TSC expenses incurred during the reconciliation period. The costs incurred to cashout excess net generation are included as expenses in the TSC reconciliation. The resulting over- or under-collection is incorporated into the subsequent TSC rate.

b. The actual net metering expense in the TSC Recon tab is the TSC portion of the net metering excess generation expense incurred during the reconciliation period that is recovered through the TSC. The net metering expense in the TSC Rate tab is a portion of the projected net metering expenses incorporated into the calculation of the TSC rate for the applicable period.

c. See response for part b.

d. It is true that a portion of those net metering expenses would, in practice, be recovered through the TSC; however, the Company's analysis isolated the impact to the GSC-1 rate and held the TSC rate constant in order to provide an illustration of the directional impact and general magnitude of the expense increase on the overall PTC and because the MRPL proposal in this proceeding is relevant to the GSC-1 and GSC-2 rates and not the TSC rate. In practice, the increase in the net metering expense would increase both the GSC-1 rate

and the TSC rate through each rate's e-factor component.

e. If the net excess generation exceeds the total default service obligation, the wholesale supplier obligations would be zero. See Article 1 Definitions on page 10 of JSA IX-6 Attachment 1, that defines the Default Service Load.

CGC Exhibit 6

DEFAULT SERVICE

SUPPLIER MASTER AGREEMENT (SMA)

BETWEEN

PPL ELECTRIC UTILITIES CORPORATION

AND

[DS SUPPLIER NAME]

DATED _____

DEFAULT SERVICE SUPPLIER MASTER AGREEMENT

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DEFAULT SERVICE SUPPLIER MASTER AGREEMENT

THIS DEFAULT SERVICE SUPPLIER MASTER AGREEMENT, made and entered into this _____ day of _____, _____ ("Effective Date"), by and between PPL Electric Utilities Corporation (the "Company" and "Buyer"), a corporation and a public utility organized and existing under the laws of the Commonwealth of Pennsylvania and _____ ("DS Supplier"), the Company and the DS Supplier hereinafter sometimes referred to collectively as the "Parties", or individually as a "Party",

WITNESSETH:

WHEREAS, the Company is an electric public utility engaged, inter alia, in providing retail electric service within its service territory located in the Commonwealth of Pennsylvania; and

WHEREAS, the Pennsylvania Public Utility Commission ("PaPUC" or "Commission") Orders issued pursuant to the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801-2812, direct Buyer to supply electric service to Default Service Load within Buyer's Pennsylvania franchise service territory; and

WHEREAS, the PaPUC has found that, for periods further identified in Appendix C and Transaction Confirmation(s) under this Agreement, it would serve the public interest for the Company to secure Default Service Supply ("DS Supply") through a competitive procurement process ("DS Solicitation") and the PaPUC has approved such a process; and

WHEREAS, the Company has conducted and completed a successful DS Solicitation for the provision of DS Supply, and the DS Supplier was one of the winning

bidders in the DS Solicitation; and

WHEREAS, pursuant to the competitive bidding procedures of the DS Solicitation, the Company and the DS Supplier desire to enter into this Agreement setting forth their respective rights and obligations concerning the provision of DS Supply.

NOW, THEREFORE, in consideration of the mutual covenants and promises set forth below, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto, intending to be legally bound, hereby covenant, promise and agree as follows:

ARTICLE 1
DEFINITIONS

Any capitalized or abbreviated term not elsewhere defined in this Agreement shall have the definition set forth in this Article.

Alternative Energy Credit or "AEC" – Shall have the meaning ascribed thereto in the AEPS Act.

AEPS Act – The Pennsylvania Alternative Energy Portfolio Standards Act, 73 P.S. §§ 1648.1-1648.8.

Affiliate – Shall mean, with respect to any entity, any other entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such entity. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

Allocated AECs – Shall mean the types and amounts of AECs specified on Appendix D and Exhibit 2.

Alternative Energy Portfolio Standards or "AEPS" – Shall have the meaning ascribed to it in the Pennsylvania Alternative Energy Portfolio Standards Act, 73 P.S. §§ 1648.1-1648.8, as amended from time to time.

Ancillary Services – Shall have the meaning ascribed thereto in the PJM Agreements.

Applicable Legal Authorities – Those federal and Pennsylvania statutes and administrative rules and regulations that govern the electric utility industry in Pennsylvania, as they may be amended from time to time.

Auction Revenue Rights or "ARRs" – The current or any successor congestion management mechanisms as may be employed by PJM (whether set forth in the PJM Agreements or elsewhere) for the purpose of allocating financial congestion hedges or financial transmission auction revenue rights. As currently defined by PJM, ARRs are entitlements allocated annually by PJM which entitle the holder to receive an allocation of the revenues from the annual auction of financial transmission rights conducted by PJM pursuant to the PJM Agreements.

Bankruptcy Code – Those laws of the United States of America related to bankruptcy, codified and enacted as Title 11 of the United States Code, entitled "Bankruptcy" and found at 11 U.S.C. § 101 et seq., as such laws may be amended, modified, replaced or superseded from time to time.

Billing Month – Each calendar month during the term of this Agreement.

Block Supply – Shall mean, such MWs of around-the-clock Energy, Capacity, transmission service, Ancillary Services and associated AECs, delivered to the Delivery Point, as established by the PaPUC Orders.

Business Day – Any day on which the Company's and PJM's corporate offices are open for business and commercial banks are not authorized or required to close in New York, New York.

Capacity – "Unforced Capacity" as set forth in the PJM Agreements, or any successor, measurement of the capacity obligation of a Load Serving Entity as may be employed in PJM (whether set forth in the PJM Agreements or elsewhere).

Charge – Any fee, charge or other amount that is billable by the Company to the DS Supplier under this Agreement.

Company – PPL Electric Utilities Corporation.

Costs – With respect to the Non-Defaulting Party, brokerage fees, commissions and other similar transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace Transaction(s) under this Agreement; and all

reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of this Agreement.

Credit Limit – Shall mean an unsecured line of credit pursuant to Article 6.

Customer – Any person or entity who enters a contractual agreement with the Company to receive retail electric service including, without limitation, all persons or entities taking service under a retail tariff, eligible to receive competitive electricity supply from an EGS or DS Supplier, respectively, in accordance with the Applicable Legal Authorities.

Customer Group – Shall have the meaning ascribed to it in Appendix C.

Damages – Financial compensation from the Defaulting Party to the Non-Defaulting Party associated with the occurrence of an Event of Default or an Early Termination of this Agreement. This compensation shall be assessed pursuant to Article 5 of this Agreement.

Defaulting Party – A Party to this Agreement that has caused or precipitated an Event of Default or an Early Termination of this Agreement.

Default Service or "DS" – Electric generation service that is provided at retail pursuant to the Applicable Legal Authorities under the Company's retail electric tariffs and under any other agreements or arrangements between the Company and Customers, to any Customer that is not being served by an EGS.

Default Allocation Assessment – Shall have the meaning ascribed to it under the PJM Agreements.

Default Service Customer(s) ("DS Customer(s)") – Retail customers who are provided Default Service pursuant to the terms of this Agreement, the Applicable Legal Authorities and the Company's retail tariffs.

Default Service Fixed Price ("DS Fixed Price") – The price in dollars per MWh as determined pursuant to the DS Solicitation.

Default Service Load ("DS Load") – Shall mean the net total default service customer sales at the retail meter, plus any transmission and distribution losses and Unaccounted for Energy, adjusted for PJM's derating in conjunction with marginal loss implementation as appropriate, expressed in MWh or MW, as appropriate, for a particular class(es) of retail customers being served by Buyer pursuant to the PaPUC Orders, as such sales vary from hour to hour, in Buyer's Pennsylvania franchise service territory, as such territory exists on the Effective Date or may increase or decrease due to *de minimis* geographic border changes to the service territory that exists on the Effective Date, less excess generation purchased from net metering (customer generation) and less supply the Company is

obligated to purchase pursuant to the Public Utility Regulatory Policies Act ("PURPA"). Additionally, with respect to the Residential Customer Group, less a fractional percentage of committed energy and capacity obtained under long-term contract with Allegheny Electric Cooperative, Inc. for supply from the New York Power Authority ("NYPA") and less Block Supply. For the purposes of this Agreement, Time-of-Use load will be included in the calculation of DS Load.

Default Service Solicitation ("DS Solicitation") – The competitive bidding processes, procedures and rules employed by the Company to competitively procure DS Supply for purposes of this Agreement.

Default Service Supplier ("DS Supplier") – An entity that (i) has been selected through the DS Solicitation and has accepted the obligations and associated rights to provide DS Supply to the Company for DS Customers in accordance with the Applicable Legal Authorities, (ii) has entered into this Agreement with the Company as a Party, and (iii) is a PJM Member and registered with PJM as an LSE.

Default Service Supplier Responsibility Share ("DS Supplier Responsibility Share") – The fixed percentage share of the Company's DS Load for a given Customer Group as indicated in the Transaction Confirmation which the DS Supplier is responsible.

Default Service Supply ("DS Supply") – Shall mean Full Requirements Service as detailed in Appendix C that the DS Supplier is required to provide in order to meet the DS Supplier's DS Supplier Responsibility Share.

Delivery Period – The period of months, as specified on an executed Transaction Confirmation, where a DS Supplier has an obligation to provide service.

Delivery Point – Shall mean the applicable zone or aggregate of the Company as designated by PJM and set forth in the Transaction Confirmation.

Early Termination – Termination of this Agreement prior to the end of the term of all Transactions under this Agreement due to the occurrence of an Event of Default as specified in Section 5.1 of this Agreement and the declaration of Early Termination as specified in Section 5.4.

Early Termination Date – The date upon which an Early Termination becomes effective as specified in Section 5.4 of this Agreement.

Electric Distribution Company or "EDC" – A public utility providing facilities for the transmission and distribution of electricity to retail customers in Pennsylvania.

Electric Generation Supplier or "EGS" – A person or entity that is duly certified by the Commission to offer and provide competitive electric supply to retail customers located in the Commonwealth of Pennsylvania.

Emergency – (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a condition that requires implementation of Emergency Operations Procedures as defined in the PJM Agreements or PJM manuals; or (iii) any other condition or situation that the Company or PJM deems imminently likely to endanger life or property or to affect or impair the Company's electrical system or the electrical system(s) of other(s) to which the Company's electrical system is directly or indirectly connected (a "Connected Entity"). Such a condition or situation may include, but shall not be limited to, potential overloading of the Company's transmission and/or distribution circuits, PJM minimum generation ("light load") conditions, or unusual operating conditions on either the Company's or a Connected Entity's electrical system, or conditions such that the Company is unable to accept Energy from the DS Supplier without jeopardizing the Company's electrical system or a Connected Entity's electrical system. Other additional emergencies can only be declared by PJM, FERC, or the PaPUC.

Energy – Three-phase, 60-cycle alternating current electric energy, expressed in units of kilowatt-hours or megawatt-hours.

Event of Default – A Party's breach of obligations under this Agreement as set forth in Article 5 of this Agreement.

FERC – The Federal Energy Regulatory Commission or its successor.

Final Hourly Energy Allocation or "FHEA" – A quantity in MWh which, for any hour, is the PHEA, adjusted for any billing or metering errors found subsequent to the calculation of PHEA, of which PJM is notified within 60 days.

Final Monthly Energy Allocation or "FMEA" – A quantity of Energy which, for any Billing Month, is the PMEA adjusted for any billing or metering data received subsequent to the calculation of PMEA of which PJM is notified within 60 days.

Fixed Price Transaction – A Transaction for Full Requirements Service on a fixed price basis as indicated on the Transaction Confirmation.

Force Majeure - An event or circumstance which prevents one Party from performing its obligations under one or more transactions, including but not limited to, riots or revolutions, demands or embargoes of the United States Government, fire, flood, drought, insurrection, acts of God which are not within the reasonable control of, or the results of

the negligence of the affected Party and which, by the exercise of due diligence, the Party is unable to mitigate or avoid or cause to be avoided. Notwithstanding the foregoing, under no circumstance shall an event of Force Majeure be based on: (i) the loss or failure of DS Supplier's supply; (ii) DS Supplier's ability to sell the DS Supply at a price greater than that received under any Transaction; (iii) curtailment by a utility transmitting DS Supply; (iv) the Company's ability to purchase the DS Supply at a price lower than paid under any Transaction; (v) any change in requirements of any governmental authority; or (vi) labor stoppage or lockout.

Gains – With respect to any Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from an Early Termination of this Agreement, determined in a commercially reasonable manner.

Generator Attribute Tracking System or "GATS" - The system owned and operated by PJM Environmental Information Services, Inc. to provide reporting and tracking services to its subscribers in support of the AEPS Act, or any successor credit registry selected by the PaPUC (as specified in Appendix D).

Guaranty – A guaranty, suretyship, hypothecation agreement, margins or security agreement or any other document in the form attached as EXHIBIT 6 – UNCONDITIONAL GUARANTYto this Agreement or other form approved by the Company.

Guarantor – Any party having the authority and agreeing to guarantee the DS Supplier's financial obligations under this Agreement, recognizing that such party shall be obligated to meet the Company's creditworthiness requirements specified in this Agreement for such DS Supplier.

Interest Index – The average Federal Funds Effective Rate for the period of time the funds are on deposit. The Federal Funds Effective Rate is published daily on the Federal Reserve website (http://www.federalreserve.gov/releases/h15/update/).

Kilowatt or "kW" – Unit of measurement of useful power equivalent to 1000 watts.

Kilowatt-hour or "kWh" – One kilowatt of electric power used over a period of one hour.

Large Commercial and Industrial Customer Group – Group of Rate Schedules that comprise the large commercial and industrial class for DS Supply and itemized in Appendix C.

Load Serving Entity or "LSE" – Shall have the meaning ascribed to it in the PJM Agreements.

Losses – With respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from an Early Termination of this Agreement, determined in a commercially reasonable manner.

Margin – The amount by which the Total Exposure Amount exceeds the DS Supplier's, or Guarantor's, Credit Limit as defined in Section 6.4 Credit Limit.

Mark-to-Market ("MtM") Exposure Amount –Shall have the meaning ascribed to it in Section 6.3 of this Agreement.

Market Price Hub - A liquid pricing point located within PJM's geographic footprint, as specified in Appendix B.

Maximum Credit Limit – The lesser of the applicable percentage of TNW or the applicable Credit Limit Cap as specified in Appendix A of this Agreement.

Megawatt or MW – One thousand kilowatts.

Megawatt-hour or MWh – One megawatt of electric power used over a period of one hour.

Merger Event – When a DS Supplier consolidates or amalgamates with, or merges into or with, or transfers all or substantially all of its assets to another entity and either (i) the resulting entity fails to assume all of the obligations of such DS Supplier hereunder as determined in the reasonable discretion of the Company or (ii) the benefits of any credit support provided pursuant to ARTICLE 6 CREDITWORTHINESS of this Agreement fail to extend to the performance by such resulting, surviving or transferee entity of the DS Supplier's obligations hereunder, and the resulting entity or its guarantor fails to meet the creditworthiness requirements of this Agreement as determined in the reasonable discretion of the Company.

Minimum Rating – A minimum senior unsecured long-term debt rating as defined in Appendix A of this Agreement.

Minimum Transfer Amount - $100,000.00.

NERC – The North American Electric Reliability Council or its successor.

Network Integration Transmission Service or "NITS" – "Network Integration Transmission Service" under the PJM Agreements in effect as of the date of this Agreement, or its successor, superseding or amended versions of the PJM Agreements that may take effect from time to time over the term of this Agreement. In the event the PJM Agreements are modified such that "Network Integration Transmission Service" is no

longer offered, Network Integration Transmission Service shall mean the type of transmission service offered under the PJM Agreements that is accorded the highest level of priority for scheduling and curtailment purposes.

Non-Defaulting Party - A Party to this Agreement who, at the time an Event of Default occurs, is not itself in default of this Agreement and has not otherwise caused or precipitated an Event of Default or Early Termination of this Agreement.

Non-market-based Transmission Services - Shall mean Network Integration Transmission Services ("NITS"), Transmission Enhancement Costs, Expansion Cost Recovery Costs, Non-Firm Point-to-Point Transmission Service Credits, Regional Transmission Expansion Plan ("RTEP"), and Generation Deactivation Charges. These terms shall have the meaning ascribed to them in the PJM Agreements.

Off-Peak Energy Forward Price - Shall mean the price for Off-Peak Hours for each Billing Month of the delivery period stated in terms of $/MWh as based on commercially available market prices at the Market Price Hub. In the event that the Market Price Hub is no longer available or no longer representative of a transparent trading hub, the Parties will negotiate in good faith to agree upon an alternate liquid price.

Off-Peak Hours – Shall mean those hours which are not On-Peak Hours**.**

On-Peak Energy Forward Price – Shall mean the price for On-Peak Hours for each Billing Month of the delivery period stated in terms of $/MWh as based on commercially available market prices at the Market Price Hub. In the event that the Market Price Hub is no longer available or no longer representative of a transparent trading hub, the Parties will negotiate in good faith to agree upon an alternate liquid price.

On-Peak Hours – Shall mean Hour Ending ("HE") 0800 through HE 2300 EPT, Monday through Friday, excluding Saturday, Sunday and PJM holidays.

PaPUC or Commission – The Pennsylvania Public Utility Commission or its successor.

PJM – PJM Interconnection L.L.C. or its successor.

PJM Agreements – The PJM OATT, PJM RAA, PJM OA and all other PJM agreements, procedures, manuals and documents applicable to the Transactions covered by or relating to this Agreement.

PJM Control Area – That certain Control Area encompassing electric systems in parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia, as

may be modified from time to time, and which is recognized by the North American Electric Reliability Council as the "PJM Control Area".

PJM Final Zonal Net Load Price – Shall have the meaning ascribed to it in the PJM Agreements.

PJM Member – A member in good standing of PJM that satisfies the requirements to conduct business with PJM.

PJM OA – The PJM Operating Agreement or the successor, superseding or amended version of the PJM Operating Agreement that may take effect from time to time.

PJM OATT – The PJM Open Access Transmission Tariff or the successor, superseding or amended version of the PJM Open Access Transmission Tariff that may take effect from time to time.

PJM OI – The PJM Office of Interconnection, the system operator for the PJM Control Area or its successor.

PJM RAA – The PJM Reliability Assurance Agreement or the successor, superseding or amended version of the PJM Reliability Assurance Agreement that may take effect from time to time.

PHEA/FHEA Adjustment Amount – For any Billing Month, the monetary amount due to the DS Supplier or the Company, as the case may be, in order to reconcile any difference between the PHEA used for the purpose of calculating estimated payments made to the DS Supplier for a given hour and the FHEA used for calculating the final payments due to the DS Supplier for such hour as more fully described in Article 9 hereof.

PMEA/FMEA Adjustment Amount – For any Billing Month, the monetary amount due to the DS Supplier or the Company, as the case may be, in order to reconcile any difference between the PMEA used for the purpose of calculating estimated payments made to DS Supplier for a given month and the FMEA used for calculating the final payments due to the DS Supplier for such month as more fully described in Article 9 hereof.

Preliminary Hourly Energy Allocation or "PHEA" – A quantity in MWh which, for any hour, is the preliminary calculation of the DS Supplier's DS Supplier Responsibility Share for that hour.

Preliminary Monthly Energy Allocation or "PMEA" – A quantity of Energy which, for any Billing Month, is the preliminary calculation of the DS Supplier's DS Supplier Responsibility Share for that Billing Month.

Rate Schedule(s) – Shall mean the specified existing and modified or successor customer rate schedule(s) in the electric service tariff of the Company filed with the Commission.

Reliability First Corporation or "RFC" – The approved regional NERC entity with responsibility for the Commonwealth of Pennsylvania or its successor.

Residential Customer Group – Group of Rate Schedules that comprise the residential class for the DS Supply and itemized in Appendix C.

Rounding Amount - $100,000.

Settlement Amount – With respect to a Non-Defaulting Party, the net amount of the Losses or Gains, and Costs, expressed in U.S. Dollars, which such Party incurs as a result of Early Termination, as set forth in Section 5.4(a) of this Agreement. For the purposes of calculating the Termination Payment, the Settlement Amount shall be considered an amount due to the Non-Defaulting Party under this Agreement if the total of the Losses and Costs exceeds the Gains and shall be considered an amount due to the Defaulting Party under this Agreement if the Gains exceed the total of the Losses and Costs.

Small Commercial and Industrial Customer Group – Group of Rate Schedules that comprise the small commercial and industrial class for DS Supply and itemized in Appendix C.

Spot Market Transaction – A Transaction for Full Requirements Service with spot market pricing as indicated on the Transaction Confirmation.

Statement – A monthly report prepared by the Company for the DS Supplier indicating the amount due to the DS Supplier by the Company as compensation for DS Supply supplied to DS Customers by the DS Supplier during a given Billing Month, in accordance with DS Supplier's obligations under this Agreement.

Supply Day – Any calendar day during the term of this Agreement on which the DS Supplier is providing, or is obligated by this Agreement to provide, DS Supply to the Company's DS Customers.

Tangible Net Worth or "TNW" – Shareholder equity less intangible assets, prepayments, and other relevant factors, as determined from audited financial statements and reviewed and adjusted as necessary. Intangible assets include benefits such as goodwill, patents, copyrights and trademarks.

Termination Payment – A payment resulting from an Early Termination that is calculated in accordance with Section 5.4.

Tier I AEC – Shall mean an AEC generated by a non-solar photovoltaic energy source that will satisfy the non-solar photovoltaic Tier I requirements of the AEPS Act applicable to the Company (as specified in Appendix D and Exhibit 2).

Tier I (Solar) AEC – Shall mean an AEC generated by a solar photovoltaic energy source that will satisfy the Tier I solar photovoltaic requirements of the AEPS Act applicable to the Company (as specified in Appendix D and Exhibit 2).

Tier II AEC - Shall mean an AEC generated by a non-solar photovoltaic energy source that will satisfy the Tier II requirements of the AEPS Act applicable to the Company (as specified in Appendix D and Exhibit 2).

Total Exposure Amount – An amount calculated daily for the DS Supplier reflecting the total credit exposure to the Company and consisting of the sum of (i) the Mark-to-Market Exposure Amount for all Fixed Price Transactions for DS Supply arising under this Agreement; (ii) the amount designated as the "credit exposure" for all Spot Market Transactions under this Agreement; (iii) any amount(s) designated as the "Mark-to-Market Exposure" arising under any other agreements providing for DS Supply or similar default service on a fixed price basis minus amounts due pursuant to such transactions; and (iv) the amount designated as the "credit exposure" under any other agreements providing for DS Supply or similar default service; provided that in the event the amount calculated for any day is a negative number, it shall be deemed to be zero for such day.

Tranche – A fixed percentage share of the Company's DS Load for the Customer Group as indicated in any given Transaction Confirmation.

Transaction – Shall mean a particular agreement by which the Company purchases and the DS Supplier sells DS Supply pursuant to this Agreement, the details of which are more fully set forth in the Transaction Confirmation(s) in the form attached as Exhibit 1.

Transaction Confirmation – Shall have the meaning ascribed to it in Appendix C and shall be in a form substantially as set forth in Exhibit 1 of this Agreement.

Transaction Date – Shall mean the date that a Transaction is effective as set forth in the Transaction Confirmation.

Unaccounted for Energy – Shall mean an energy accounting adjustment for settlement purposes among retail energy suppliers at the Delivery Point. Unaccounted for Energy is distributed among all retail energy suppliers at the Delivery Point on an hourly basis.

ARTICLE 2
GENERAL TERMS AND CONDITIONS

2.1 Capacity In Which Company Is Entering Into This Agreement

The DS Supplier agrees and acknowledges that the Company is contracting for the provision of DS Supply from such DS Supplier for Customers receiving Default Service on the Company's electric system pursuant to the authorizations provided to the Company. The DS Supplier further agrees and acknowledges that the Company will administer and monitor the DS Supplier's performance in providing DS Supply under this Agreement and that the Company shall be entitled to enforce the DS Supplier's obligations related to the provision of DS Supply. The DS Supplier hereby agrees that the Company is entitled to seek enforcement of this Agreement on behalf of the Customers. It is the specific intention of the Parties hereto that Customers and Customer groups are not third party beneficiaries of this Agreement and that no Customer or Customer group shall seek enforcement of this Agreement against the DS Supplier on their own behalf, either independently or by joining in any legal proceeding brought by the Company.

The Parties acknowledge that the Agreement is a "forward contract" within the meaning of the United States Bankruptcy Code ("USBC"), that each Party hereto is a "forward contract merchant" within the meaning of the USBC, that all setoffs, netting and liquidations contemplated hereunder constitute "settlement payments" within the meaning of the USBC, that each payment or transfer of performance assurance is a "margin payment", "settlement payment" or transfer within the meaning of the USBC, and, accordingly, the Parties hereto are entitled to the protections of Section 556 of the

Bankruptcy Code. The Parties therefore agree that the Agreement may be terminated by either Party upon the commencement of a proceeding by the other Party under any chapter of the Bankruptcy Code in accordance with Section 5.2 of this Agreement.

2.2 Parties' Obligations

(a) Obligations of DS Supplier

The DS Supplier hereby agrees as follows:

(i) To provide service on a firm and continuous basis such that the supply delivered for the term of each Transaction under the Agreement meets the terms and conditions set forth in Appendix C and the applicable Transaction Confirmation;

(ii) To provide sufficient quantities of DS Supply on an instantaneous basis at all times during the Delivery Period of each Transaction and supplied to the Delivery Point to meet the DS Supplier Responsibility Share;

(iii) To procure those services provided by the PJM OI and to perform such functions as may be required by the PJM OI that are necessary for the delivery of DS Supply required hereunder;

(iv) To cooperate with the Company in any regulatory compliance efforts that may be required to maintain the ongoing legitimacy and enforceability of the terms of this Agreement and to fulfill any regulatory reporting requirement associated with the provision of DS Supply before the PaPUC, the FERC or any other regulatory body asserting jurisdiction;

(v) To become the LSE with respect to the provision of DS Supply for the DS

Supplier Responsibility Share and to comply with all requirements of an LSE with respect to such DS Supplier Responsibility Share;

(vi) To pay to the Company the PMEA/FMEA Adjustment Amount for any Billing Month in which the PMEA exceeds the FMEA, and to pay to the Company adjustments pursuant to Sections 9.1(b)(iii) and 9.1(b)(iv) if applicable, as more fully described in Article 9 of this Agreement;

(vii) To accept assignment of and to fulfill all obligations of an LSE that are assigned to it by this Agreement;

(viii) To comply in a timely manner with all obligations under this Agreement imposed upon the DS Supplier; and

(ix) To comply with the AEPS requirements set forth in Appendix D and Exhibit 2.

(b) Obligations of the Company

The Company hereby agrees as follows:

(i) To pay to the DS Supplier every month an amount due, resulting from the calculations, as detailed in Article 9 of this Agreement, subject to the adjustments as expressed therein;

(ii) To pay to the DS Supplier the PMEA/FMEA Adjustment Amount for any Billing Month in which the FMEA exceeds the PMEA, and to pay to the DS Supplier adjustments pursuant to Sections 9.1(b)(iii) and 9.1(b)(iv) if applicable, as more fully described in Article 9 of this Agreement;

(iii) To provide to the DS Supplier its estimated aggregate load obligation (Capacity MW value) for each Supply Day no less than five (5) calendar days prior to the day of delivery. Further, this information will be posted in the DS Supplier's specific PJM eMTR account, or successor system or process;

(iv) To comply in a timely manner with all obligations under this Agreement imposed upon the Company; and

(v) Accept the delivery of DS Supply necessary to meet the DS Load.

2.3 Congestion and Congestion Management

The DS Supplier is responsible for any congestion costs incurred to meet the DS Supplier Responsibility Share. The Company shall transfer or assign to the DS Supplier the Company's rights to ARRs to which the Company is entitled as an LSE pursuant to the PJM Agreements, provided that such rights are related to the service being provided to meet the DS Supplier Responsibility Share and such rights are for the Delivery Period indicated in the Transaction Confirmation(s). All rights, liabilities and obligations associated with such ARRs will accrue and be assumed by the DS Supplier through the transfer or assignment from the Company to the DS Supplier including the responsibility and ability of the DS Supplier to request or nominate such ARRs when applicable and feasible. Should the conditions above not be met, the entity recognized by PJM as having the right to make the nominations will nominate such ARRs for the upcoming PJM planning period and such ARRs will be allocated to the DS Supplier in accordance with the PJM Agreements based upon its DS Supplier Responsibility Share.

2.4 PJM Services

(a) The DS Supplier shall make all necessary arrangements for the delivery of DS Supply through the PJM OI. The Company will advise the PJM OI of the magnitude and location of the DS Supplier's actual DS Supplier Responsibility Share, as required by the PJM OI, for the purpose of calculating such DS Supplier's appropriate DS Supply requirements related to the provision of service under this Agreement by DS Supplier arising under the PJM Agreements. The DS Supplier shall remain responsible to PJM for the performance of its LSE obligations associated with the provision of DS Supply under this Agreement until the effective date of the transfer of such LSE obligations.

(b) The Company will manage PJM load response programs in accordance with PJM Agreements as amended from time to time and the provisions of its applicable riders and retail electric service tariffs, as amended and approved by the PaPUC from time to time, or the Company customer contracts, as amended by the Company from time to time. The Company will retain all of the benefits associated with its load response programs, including but not limited to all associated wholesale revenues from PJM for Capacity, Energy and Ancillary Services. Unless specifically prohibited by its retail electric service tariffs, DS Customers may, at their election, participate in demand response programs offered under the PJM Agreements.

(c) DS Supplier will be responsible for any costs regarding demand response

compensation in organized wholesale energy markets.

(d) The Company and DS Supplier shall work with PJM to establish any PJM E-Accounts necessary for the DS Supplier to provide Full Requirements Service. The Company shall generate and provide to DS Supplier PJM shortname(s) associated with supplier's unique contract type(s), as necessary. Unique shortname(s) may be generated for each differing contract type. DS Supplier shall complete all required forms and processing to PJM to create shortname(s) within the PJM system.

(e) Upon DS Supplier's creation of new shortname(s), the Company shall establish PJM E-Account contract(s) for the entire duration of the Transaction(s).

(f) The Company will complete and partially execute the PJM Declaration of Authority, Exhibit 4, and issue to the DS Supplier to execute. The PJM Declaration of Authority will be used to allocate PJM costs, in association with the shortnames created in accordance with Section 2.4(d) above, and Appendix C.

(g) Following the Company's establishing new contracts within the PJM eSuite system, the DS Supplier shall review and confirm the PJM E-Account contract(s) for the entire duration of the Transaction(s).

(h) For the period of time this Agreement is in effect, DS Supplier shall be: (i) a member in good standing of PJM; (ii) qualified as a PJM "Market Buyer" and "Market Seller" pursuant to the PJM Agreements; and (iii) qualified as

a PJM "Load Serving Entity." For the period of time this Agreement is in effect, the Company shall be a member in good standing of PJM.

(i) For the period of time this Agreement is in effect, both the Company and DS Supplier shall have executed the PJM Declaration of Authority (Exhibit 4), which shall remain in effect during the term of each Transaction under this Agreement. In the event PJM requires that the Declaration of Authority be amended after execution by the DS Supplier, DS Supplier agrees to execute a revised PJM Declaration of Authority in accordance with PJM requirements.

2.5 PJM Billing

(a) Buyer and DS Supplier shall direct PJM to invoice DS Supplier and Buyer for charges and credits relating to DS Supplier's and Buyer's rights and obligations under this Agreement. If PJM is unable to invoice charges or credits in accordance with this Agreement, Buyer and DS Supplier shall rectify such PJM invoice discrepancy in the invoice sent pursuant to Section 9 (Billing and Payment).

(b) The Parties agree that the PJM bill may change from time to time. Allocation of any charges that are reflected in a PJM bill that are not included on or are inconsistent with this Agreement will be determined pursuant to Appendix C (DS Supply Specifications), Section 2.4 (PJM Services), and Section 2.6 (PJM Agreement Modifications) of this Agreement.

2.6 PJM Agreement Modifications

(a) If the PJM Agreements are amended or modified so that any schedule or section references herein to such agreements is changed, such schedule or section references herein shall be deemed to automatically (and without any further action by the Parties) refer to the new or successive schedule or section in the PJM Agreements which replaces that originally referred to in this Agreement.

(b) If the applicable provisions of the PJM Agreements referenced herein, or any other PJM rules relating to the implementation of this Agreement, are changed materially from those in effect on the Effective Date, both Parties shall cooperate to make conforming changes to this Agreement to fulfill the purposes of this Agreement, including the DS Supplier's responsibility for changes in PJM products and pricing during the term of each Transaction under this Agreement.

2.7 PJM Member Default Cost Allocation

In the event PJM imposes a Default Allocation Assessment upon the Company relating to a default during the term of Transaction(s) under this Agreement, the Company shall invoice DS Supplier, and DS Supplier shall pay an amount equal to the product of (i) DS Supplier Responsibility Share and (ii) the Default Allocation Assessment, less the amounts of any types of charges allocated to the Company under this Agreement that are used by PJM in calculating such Default Allocation Assessment.

2.8 Other Fines and Penalties

If fees, fines, penalties, or costs are claimed or assessed against the Company by any Applicable Legal Authority or PJM due to non-compliance by the DS Supplier with this Agreement, any other requirements of law or the PJM Agreements, the DS Supplier shall indemnify and hold the Company harmless against any and all losses, liabilities, damages, and claims suffered or incurred by the Company, including claims for indemnity or contribution made by third parties against the Company and Company's costs and attorney's fees incurred on account of such claims, except to the extent the Company recovers any such losses, liabilities or damages through other provisions of this Agreement.

2.9 Communications and Data Exchange

The DS Supplier and the Company shall supply to each other in a thorough and timely manner all data, materials or other information that is specified in this Agreement, or that may otherwise reasonably be required by DS Supplier or by the Company in connection with the provision of DS Supply by the DS Supplier to DS Customers, if required.

The DS Supplier shall be equipped with the communications capabilities necessary to comply with the communications and data exchange standards that are set by and as may, from time to time, be modified by PJM, and shall exclusively bear the costs of installing, maintaining, testing, and operating all required information technology systems that will enable it to send to and receive data from the Company and PJM and to satisfy its obligations under this Agreement, the PJM Agreements and all other relevant agreements.

2.10 Record Retention

The Company shall retain necessary records for the longer of four years or as required under applicable PaPUC requirements so as to permit DS Supplier to confirm the validity of payments due to DS Supplier hereunder; provided that if the DS Supplier has provided notice pursuant to this Agreement that it disputes the validity of any payments, the Company agrees that it shall retain all records related to such dispute until the dispute is finally resolved.

2.11 Verification

In the event of a good faith dispute regarding any invoice issued or payment due under this Agreement, and provided that a mutually acceptable confidentiality agreement is executed by the Parties, each Party will have the right to verify, at its sole expense, the accuracy of the invoice or the calculation of the payment due by obtaining copies of relevant portions of the books and records of the other Party.

ARTICLE 3
REPRESENTATIONS AND WARRANTIES

3.1 DS Supplier's Representations and Warranties

The DS Supplier hereby represents, warrants and covenants to the Company as of the Effective Date and throughout the term of the Transaction(s) under this Agreement as follows:

(a) It is a corporation, partnership, limited liability company or other legal entity, duly organized, validly existing and in good standing under the laws

of the Commonwealth of Pennsylvania or, if another jurisdiction, under the laws of such jurisdiction and, in such case, is duly registered and authorized to do business in such other jurisdiction and in the Commonwealth of Pennsylvania;

(b) It has all requisite power and authority to execute and deliver this Agreement and to carry on the business to be conducted by it under this Agreement and to enter into and perform its obligations hereunder, including satisfaction of all applicable FERC requirements;

(c) The execution and delivery of this Agreement and the performance of such DS Supplier's obligations hereunder have been duly authorized by all necessary action on the part of the DS Supplier and do not and will not conflict with, or constitute a breach of or default under, any of the terms, conditions, or provisions of the DS Supplier's certificate of incorporation or bylaws or other constituent instruments or any indenture, mortgage, other evidence of indebtedness, or other agreement or instrument or any statute or rule, regulation, order, judgment, or decree of any judicial or administrative body to which the DS Supplier is a party or by which the DS Supplier or any of its properties is bound or subject;

(d) All necessary and appropriate action that is required on the DS Supplier's part to execute this Agreement has been completed;

(e) This Agreement is the legal, valid and binding obligation of the DS Supplier, enforceable in accordance with its terms, except as such

enforceability may be limited by applicable bankruptcy, insolvency or similar laws from time to time in effect that affect creditors' rights in general or by general principles of equity;

(f) There are no actions at law, suits in equity, proceedings or claims pending or, to the DS Supplier's knowledge, threatened against the DS Supplier before any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the DS Supplier's performance of its obligations under this Agreement;

(g) It has entered into this Agreement and all Transactions under this Agreement with a full understanding of the material terms and risks of the same, and it is capable of assuming those risks;

(h) It is in good standing as an LSE in PJM, is a signatory to all applicable PJM Agreements, and is in compliance with, and will continue to comply with, all obligations, rules and regulations, as established and interpreted by the PJM OI, that are applicable to LSEs as defined by the PJM Agreements; provided that the DS Supplier shall not be obligated to become an LSE in PJM until the date it begins providing DS Supply;

(i) It has made its trading and investment decisions (including regarding the suitability thereof) based upon its own judgment and any advice from such advisors as it has deemed necessary and not in reliance upon any view expressed by the Company;

(j) It will comply with any and all information and data transfer protocols that

may be adopted by the Company or that are set by, and from time to time modified by, the PaPUC; provided that DS Supplier shall be entitled to exercise its reserved right to challenge any such protocols in the appropriate forum;

(k) It is not bankrupt or insolvent and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming bankrupt or insolvent;

(l) No Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement;

(m) It is not relying upon the advice or recommendations of the other Party in entering into this Agreement, it is capable of understanding, understands and accepts the terms, conditions and risks of this Agreement, and the other Party is not acting as a fiduciary for or advisor to it in respect of this Agreement; and

(n) It has entered into this Agreement and all Transactions under this Agreement in connection with the conduct of its business and it has the capacity or ability to provide or take delivery of DS Supply as required by this Agreement; and it is an “eligible contract participant” as defined in Section 1a(18) of the Commodity Exchange Act.

3.2 Company's Representations and Warranties

The Company hereby represents, warrants and covenants to the DS Supplier as of the Effective Date and throughout the term of the Transaction(s) under this Agreement as follows:

(a) The Company is an electric utility corporation duly organized, validly existing and in good standing under the laws of the Commonwealth of Pennsylvania;

(b) The Company has all requisite power and authority to carry on the business to be conducted by it under this Agreement and to enter into and perform its obligations hereunder;

(c) The execution and delivery of this Agreement and the performance of the Company's obligations hereunder have been duly authorized by all necessary action on the part of the Company and do not and will not conflict with, or constitute a breach of or default under, any of the terms, conditions, or provisions of the Company's certificate of incorporation or bylaws or other constituent instruments or any indenture, mortgage, other evidence of indebtedness, or other agreement or instrument or any statute or rule, regulation, order, judgment, or decree of any judicial or administrative body to which the Company is a party or by which the Company or any of its properties is bound or subject;

(d) All necessary and appropriate action that is required on the Company's part to execute this Agreement has been completed;

(e) This Agreement is the legal, valid and binding obligation of the Company, enforceable in accordance with its terms, except as such enforceability may be limited by applicable bankruptcy, insolvency or similar laws from time to time in effect that affect creditors' rights in general or by general principles of equity and the Commission's power under section 508 of the Public Utility Code, 66 Pa.C.S. § 508, to amend or modify the contracts of public utilities;

(f) The ability of the Company to pay any and all amounts due and payable under this Agreement, or upon any potential breach thereof, is not conditioned upon any governmental or administrative appropriation by the Commission, the Commonwealth of Pennsylvania or any other governmental authority;

(g) There are no actions at law, suits in equity, proceedings or claims pending or, to the Company's knowledge, threatened against the Company before any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the Company's performance of its obligations under this Agreement;

(h) It has entered into this Agreement and all Transactions under this Agreement with a full understanding of the material terms and risks of the same, and it is capable of assuming those risks;

(i) It is in good standing with PJM, is a signatory to all applicable PJM Agreements, and is in compliance with, and will continue to comply with,

all obligations, rules and regulations applicable to Company, as established and interpreted by the PJM OI;

(j) The Company's performance under this Agreement is not contingent upon the performance of Customers or the ability of Customers to pay rates;

(k) The Company shall have sole responsibility for metering and billing with respect to DS Customers;

(l) The Company shall be responsible for electric distribution services and the DS Supplier shall not be responsible for distribution charges;

(m) It has made its trading and investment decisions (including regarding the suitability thereof) based upon its own judgment and any advice from such advisors as it has deemed necessary and not in reliance upon any view expressed by the DS Supplier;

(n) It is not bankrupt or insolvent and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming bankrupt or insolvent;

(o) No Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement;

(p) It is not relying upon the advice or recommendations of the other Party in entering into this Agreement, it is capable of understanding, understands and accepts the terms, conditions and risks of this Agreement, and the other

Party is not acting as a fiduciary for or advisor to it in respect of this Agreement; and

(q) It has entered into this Agreement and all Transactions under this Agreement in connection with the conduct of its business and it has the capacity or ability to provide or take delivery of DS Supply as required by this Agreement; and it is an "eligible contract participant" as defined in Section 1a(18) of the Commodity Exchange Act.

3.3 Survival of Obligations

All representations and warranties contained in this Article must be maintained up through the termination or expiration of all Transactions under this Agreement. If a Party learns that any of the representations, warranties or covenants in this Agreement are no longer true during the term of any Transaction under this Agreement, the Party shall immediately notify the other Party via email, with a hard copy of the notice delivered by overnight mail, and Company may, in its reasonable discretion treat such occurrence as an Event of Default hereunder.

3.4 Joint Representations and Warranties

This Agreement is for the purchase and sale of Full Requirements Service that will be delivered in quantities expected to be used or sold over a defined period(s) in the normal course of business, and it is the intention at the inception and throughout the term of each Transaction under this Agreement that the Agreement will result in physical delivery and not financial settlement, and the quantity of Full Requirements Service that DS Supplier

must deliver and Company must receive will be determined by the requirements of the applicable DS Load, and, as such, the Agreement does not provide for an option by either Party with respect to the quantity of Full Requirements Service to be delivered or received during performance of the Agreement. This Agreement has been drafted to effectuate Company's and DS Supplier's specific intent so that in accordance with Accounting Standards Codification 815 ("ASC 815"), as amended, Company would be able to elect to use accrual accounting for its purchases under this Agreement, while DS Supplier would be able to elect to use either accrual or mark-to-market accounting for its sales under the Agreement. If either Company or DS Supplier determines, in good faith, that the intended accounting treatment has become jeopardized, due to a change in interpretations of ASC 815, as amended, or otherwise, then Company and DS Supplier agree to meet and use their best efforts to reform the Agreement so that, with the minimum changes possible, the Agreement again qualifies for the intended accounting treatments.

ARTICLE 4
COMMENCEMENT AND TERMINATION OF AGREEMENT

4.1 Commencement and Termination

The term of this Agreement shall commence upon the Effective Date. Unless otherwise agreed upon by the Company and the DS Supplier, this Agreement shall continue in full force and effect from the Effective Date until the end of all Transaction(s) executed under this Agreement, unless the Agreement is terminated prematurely pursuant to the provisions of this Agreement.

4.2 Termination of Right to Supply

The DS Supplier agrees that termination of this Agreement for reason of an Event of Default shall terminate any right of the DS Supplier to provide DS Supply to the DS Customers and nullify any of the entitlements to which the DS Supplier became entitled as a result of being selected as a winning bidder in the DS Solicitation.

4.3 Survival of Obligations

Termination of this Agreement for any reason shall not relieve the Company or the DS Supplier of any obligation accrued or accruing prior to such termination. Applicable provisions of this Agreement shall continue in effect after termination to the extent necessary to provide for final billings including, without limitation, Article 4 (Commencement and Termination of Agreement), Article 5 (Breach and Default), Article 11 (Dispute Resolution), Article 13 (Limitations of Remedies, Liabilities and Damages), Article 14 (Indemnification) and Article 16 (Miscellaneous Provisions).

4.4 Mutual Termination

The Company and the DS Supplier may agree at any time during the term of this Agreement to terminate their respective rights and obligations hereunder on such terms and under such conditions that they mutually deem to be appropriate as set forth in a mutual termination agreement acceptable in form and substance to the Company and the DS Supplier ("Mutual Termination Agreement"); provided that Company may enter into such a Mutual Termination Agreement, which will discharge the terminating DS Supplier (the "Terminating DS Supplier") with respect to liabilities other than surviving obligations set

forth in Section 4.3 that arise after the effective date of the Mutual Termination Agreement if the following conditions precedent are met: (i) the Terminating DS Supplier identifies a replacement DS Supplier that expressly assumes all obligations of the Terminating DS Supplier hereunder for the remaining term of Transactions under this Agreement (the "Replacement DS Supplier"); (ii) the Replacement DS Supplier demonstrates its compliance with Article 6 of this Agreement, "Creditworthiness", as of the effective date of the Mutual Termination Agreement, that determination to be made in the reasonable discretion of Company; (iii) the Replacement DS Supplier executes a counterpart signature page to this Agreement assuming all obligations of the Terminating DS Supplier hereunder and with respect to all Transaction Confirmation(s) that are currently in effect and thereby becomes a Party under this Agreement and all relevant Transaction(s), effective immediately following the effective date of the Mutual Termination Agreement; and (iv) the Terminating DS Supplier is not, to the belief or knowledge of the Company, subject to an Event of Default as of the effective date of the Mutual Termination Agreement or, if the Company believes that the Terminating DS Supplier may be subject to an Event of Default, either (a) the Company has determined that, as of the effective date of the Mutual Termination Agreement, it has not incurred any Damages as a result of the Event of Default or (b) if the Company has determined that, as of the effective date of the Mutual Termination Agreement, it may have incurred Damages as a result of the Event of Default, the Replacement DS Supplier has agreed in writing to be responsible for the payment of such Damages or to otherwise cure the Event of Default, in either case to the satisfaction of the Company in its reasonable discretion.

ARTICLE 5
BREACH AND DEFAULT

5.1 Events of Default

An Event of Default under this Agreement shall occur if a Party (the "Defaulting Party"):

(a) Is the subject of a voluntary bankruptcy, insolvency or similar proceeding;

(b) Fails to transfer Alternative Energy Credits in compliance with the requirements of Appendix D and Exhibit 2 (DS Supplier's Obligations for AEPS Compliance) if such failure is not remedied within three (3) Business Days after written notice;

(c) In the case of a DS Supplier, fails to comply with the requirements of Section 3.1(b) and (h) if such failure is not remedied within three (3) Business Days after written notice;

(d) Makes an assignment for the benefit of its creditors;

(e) Applies for, seeks consent to, or acquiesces in the appointment of a receiver, custodian, trustee, liquidator or similar official to manage all or a substantial portion of its assets;

(f) In the case of a DS Supplier, is dissolved or is the subject of a Merger Event;

(g) Has a secured party take possession of all or substantially all of its assets or has a distress, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all of its assets;

(h) Has a resolution passed for its winding-up, official management or

liquidation;

(i) In the case of a DS Supplier, PJM terminates the DS Supplier's ability to make purchases from PJM markets or PJM holds the Company responsible for the provision of DS Supply to meet the DS Supplier's DS Supplier Responsibility Share under this Agreement and PJM does not rescind such termination or assignment of responsibility within seven (7) Business Days;

(j) Fails to comply with the creditworthiness requirements as set forth in Article 6 of this Agreement, including, without limitation, compliance with the creditworthiness requirements to cover the Margin calculated under Section 6.3 or post any performance assurance collateral as set forth in Section 6.7 to cover Margin due under Section 6.5 of this Agreement, within the time frames set forth in this Agreement;

(k) Is declared by PJM to be in default of any provision of any PJM Agreement, which default prevents a Party's performance hereunder if such failure is not remedied within three (3) Business Days after written notice;

(l) Fails to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within three (3) Business Days after written notice;

(m) Violates any federal, state or local code, regulation or statute applicable to the provision of DS Supply and/or AECs in a manner that materially, and adversely, affects the Party's performance under this Agreement, including by way of failure to continually satisfy all applicable FERC requirements,

or, in the case of the DS Supplier, by way of failure to maintain any other governmental or regulatory approvals required for participation in the Pennsylvania retail energy market, or defaults on any obligation or other failure to comply with PJM requirements under the PJM Agreements;

(n) Is the subject of an involuntary bankruptcy or similar proceeding;

(o) Subject to Section 5.3 (b) of this Agreement, in the case of the Company, fails to accept DS Supply properly tendered by the DS Supplier under this Agreement;

(p) Fails to perform or otherwise comply with any material covenant or obligation set forth in this Agreement, if such failure is not remedied within three (3) Business Days after written notice;

(q) Makes a materially incorrect or misleading representation or warranty under this Agreement or under any response to the DS Solicitation;

(r) Makes an omission or commits an act that constitutes an "Event of Default" under any other agreement(s) for the provision of DS Supply between the Company and the DS Supplier; and fails to remedy such condition, event or delinquency herein above described such that the other Party (the "Non-Defaulting Party") is completely made whole with respect to such condition, event or delinquency, within three (3) Business Days of receipt of written notice thereof from such Non-Defaulting Party; provided, however, that an Event of Default shall be deemed to have occurred immediately, without any need for the provision of notice thereof by the

Non-Defaulting Party and without any right of cure on the part of the Defaulting Party, in the event of the occurrence of a condition, event or delinquency described in subsections (a), (d), (e), (f), (g), (h), (i), and (j) above. Termination or modification of this Agreement or any Transactions hereunder by the PaPUC, other regulatory authority or court of law does not constitute an Event of Default under this Agreement; or

(s) With respect to the DS Supplier's Guarantor, if any:

1. any representation or warranty made by the Guarantor in connection with this Agreement is false or misleading in any material respect when made or when deemed made or repeated;

2. Guarantor fails to make, when due, any payment required or to perform any other material covenant or obligation in any guaranty made in connection with this Agreement and such failure shall not be remedied within three (3) Business Days after written notice;

3. Guarantor's guaranty fails to be in full force and effect for purposes of this Agreement (other than in accordance with its terms) prior to the satisfaction of all obligations of the DS Supplier under this Agreement without the written consent of the Company; or

4. Guarantor repudiates, disaffirms, disclaims, or rejects, in whole or in part, or challenges the validity of any guaranty in connection with this Agreement.

5.2 Rights upon Default

Upon and during the continuation of an Event of Default, the Non-Defaulting Party shall have the right to suspend performance, provided that such suspension shall not continue for longer than ten (10) Business Days. At any time during or subsequent to the temporary suspension of performance, the Non-Defaulting Party may proceed with the steps outlined in Sections 5.6 and 5.7. In addition to any other remedies available at law or in equity to the Non-Defaulting Party, subject to the dispute resolution provisions in Article 11 of this Agreement, if an Event of Default has occurred and is continuing, the Non-Defaulting Party shall have the right to implement all of the following remedies:

(i) Declare an Early Termination Date of this Agreement with respect to the obligations of the Defaulting Party without any liability or responsibility whatsoever except for obligations arising prior to the date of termination, by providing written notice to the Defaulting Party; provided, however, that this Agreement shall immediately terminate automatically and without notice in the case of any Event of Default in which a DS Supplier is the Defaulting Party occurring

under subsections (a), (d), (e), (f), (g), (h) (i), and (j) of Section 5.1 of this Agreement and such date of automatic termination shall be deemed the Early Termination Date of this Agreement with respect to such DS Supplier; and

(ii) Receive Damages in accordance with Section 5.3 of this Agreement.

5.3 Damages Resulting From an Event of Default

(a) **DS Supplier's Failure to Supply DS Supply or Declaration of Early Termination By Company**: Damages resulting from (i) the DS Supplier's failure to (A) provide DS Supply in conformance with Section 2.2 hereof or (B) pay PJM for purchases of any products or services from PJM, or other failure to comply with PJM requirements, such that PJM holds the Company responsible for the provision of DS Supply to meet the DS Supplier's DS Supplier Responsibility Share under Transaction(s) of this Agreement or (ii) the occurrence of any Event of Default attributable to the DS Supplier resulting in Early Termination, shall include all Costs incurred by the Company, acting in a commercially reasonable manner consistent with any statutory or regulatory requirements imposed by the Applicable Legal Authorities, in obtaining replacement services or in obtaining a replacement DS Supplier, which Costs exceed the amounts that would have been payable to the defaulting DS Supplier under this Agreement. Costs incurred by the

Company for the purpose of calculating Damages hereunder will consist of:

(1) The cost of DS Supply allocated to the Company by the PJM OI due to the failure of the DS Supplier to meet obligations owing to the PJM OI in connection with its obligations under this Agreement;

(2) The costs of DS Supply purchased by the Company to replace DS Supply that the DS Supplier was obligated to supply under this Agreement during the term hereof;

(3) Administrative and legal costs (including attorneys' fees) associated with procuring replacement DS Supply; and

(4) Financial hedging costs incurred by the Company on behalf of DS Customers as a result of having to procure DS Supply not provided by the DS Supplier.

The Parties further recognize and agree that the final calculation of Damages hereunder may not be known for some time since the level of such Damages may be dependent upon the arrangements made by the Company to obtain replacement services or a replacement DS Supplier. The Company and the DS Supplier agree that, until the calculation of Damages under this provision is completed, the amount and payment to the Company of the Settlement Amount on behalf of DS Customers in the event of an Early Termination as set forth in Section 5.4 of this Agreement shall be immediately due and owing as an estimate of all Damages ultimately determined to be due and owing. After Damages have been finally determined under this Section 5.3, the amounts of Damages due and owing

will be reconciled with payments already made by the DS Supplier under Section 5.4 of this Agreement. The DS Supplier covenants that it shall, upon request of Company, execute any tolling agreement necessary in the event that final Damages have not been determined prior to the expiration of any applicable statute of limitations or other limitation of action rule or order of court or other legal authority relating to the Company's rights to recover Damages.

(b) **Failure By Company on Behalf of Customers To Accept DS Supply Tendered By DS Supplier**: Damages resulting from the failure of the Company on behalf of Customers to accept DS Supply tendered by the DS Supplier necessary to meet the DS Supplier Responsibility Share of DS Load under Transaction(s) of this Agreement shall consist of the positive difference (if any) resulting from (i) the amounts that would have been payable to the DS Supplier hereunder had the Company accepted the DS Supply tendered by the DS Supplier necessary to meet the DS Supplier Responsibility Share of DS Load under Transaction(s) of this Agreement minus (ii) the amount realized by the DS Supplier in disposing, in a commercially reasonable manner, of the DS Supply not accepted by the Company.

(c) **Damages Resulting From Early Termination Due To An Event of Default Attributable To the Company**: Damages resulting from Early Termination due to an Event of Default attributable to the Company shall be as set forth in Section 5.4 of this Agreement. Damages calculated in

accordance with said Section 5.4 shall be the exclusive remedy available to the DS Supplier in the event of Early Termination resulting from an Event of Default attributable to the Company.

(d) **Damages Resulting from DS Supplier's Failure to Satisfy its AEPS Obligations**: Damages resulting from the DS Supplier's failure to continuously meet and satisfy all or any portion of its obligations under Section 2.2(a)(ix) of this Agreement shall include, but not be limited to, the amount of all penalties and costs associated with the procurement of additional AECs, including, without limitation, interest, attorneys' fees and other charges, if any, levied against the Company related to AEPS regulations, due to such DS Supplier's conduct or inaction. In addition to such penalties and costs, DS Supplier will remain liable for AECs that were not supplied as part of its obligations set forth in Section 2.2(a)(ix), Appendix D and Exhibit 2 of this Agreement.

(e) **Other Damages**: Damages for Events of Default not specified above shall consist of the direct Damages incurred by the Non-Defaulting Party.

(f) **Waiver of Event of Default**: If an Event of Default has occurred and the Non-Defaulting Party is the Company, then unless the Event of Default was a failure by the DS Supplier to meet any or all of its DS Supply obligations, the Company may elect, at its sole discretion, to offer to waive the default on such terms and conditions as the Company, at its sole discretion, may deem appropriate to propose a special remedy. Any such special remedy

can only be offered to the DS Supplier if it first is specifically approved by the PaPUC in accordance with Commission Orders.

5.4 Declaration of an Early Termination Date and Calculation of Settlement Amount and Termination Payment

(a) **Settlement Amount**. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the Non-Defaulting Party shall have the right (i) to designate a day, no earlier than the day such notice is effective and no later than twenty (20) days after such notice is effective, as the Early Termination Date to accelerate all amounts owing between the Parties and to liquidate and terminate the undertakings set forth in this Agreement, (ii) to withhold any payments due to the Defaulting Party under this Agreement, and (iii) to suspend performance as provided in Section 5.2 of this Agreement; provided however, that an Early Termination Date shall be deemed to occur automatically and concurrently with the Event of Default, without any requirement for the provision of notice by the Non-Defaulting Party, with respect to an Event of Default under subsections (a), (d), (e), (f), (g), (h), (i), and (j) of Section 5.1 of this Agreement. The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount with respect to the obligations under this Agreement.

☐ The DS Supplier may, in its sole discretion, add the following subsection 5.4(a)(1) by checking this box. If DS Supplier does not check this box, subsection 5.4(a)(1) will be deemed to be excluded from this Agreement.

5.4. (a) (1) For the purposes of such determination, the DS Supply

provided for under this Agreement for the period following the Early Termination Date through the remainder of the term of Transaction(s) under this Agreement shall be deemed to be those quantity amounts that would have been delivered on an hourly basis, had such Transaction(s) under this Agreement been in effect during the previous calendar year adjusted for such DS Load changes as may have occurred since the previous calendar year.

(b) **Net Out of Settlement Amounts**. The Non-Defaulting Party shall calculate a Termination Payment by aggregating all Settlement Amounts due under this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply into a single amount by netting out and setting off (i) all Settlement Amounts that are due or will become due to the Defaulting Party, plus at the option of the Non-Defaulting Party, any cash or other form of security then available to the Non-Defaulting Party and actually received, liquidated and retained by the Non-Defaulting Party, plus any or all other amounts due to the Defaulting Party under this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply against (ii) all Settlement Amounts that are due or will become due to the Non-Defaulting Party, plus any or all other amounts due to the Non-Defaulting Party under this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply, so that all such amounts shall be

netted out to a single liquidated amount; provided, however, that if the DS Supplier is the Defaulting Party and the Termination Payment is due to the DS Supplier, the Company shall be entitled to retain a commercially reasonable portion of the Termination Payment, which may be equal to the entire amount of the Termination Payment, as security for additional amounts that may be determined to be due and owing by the DS Supplier as Damages and further provided that any previously attached security interest of the Company in such retained amounts shall continue. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate. If the Termination Payment has been retained by the Company as security for additional amounts that may be determined to be due and owing by the DS Supplier, and if, upon making a final determination of Damages, the Termination Payment, or any portion thereof, is to be made to the DS Supplier, the Company will pay simple interest on the Termination Payment amount being made to the DS Supplier. Simple interest will be calculated at the Interest Index.

(c) **Notice of Termination Payment**. As soon as practicable after an Early Termination Date, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. Subject to Section 5.4(b) above, the

Termination Payment shall be made by the Party that owes it within three (3) Business Days after such notice is effective ("Termination Payment Date").

(d) **Disputes With Respect to Termination Payment**. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within three (3) Business Days of receipt of Non-Defaulting Party's calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute; provided, however, that if the Termination Payment is due from the Defaulting Party, the Defaulting Party shall first transfer collateral to the Non-Defaulting Party in an amount equal to the Termination Payment, such collateral to be in a form acceptable to the Non-Defaulting Party as specified in the notice of Termination Payment pursuant to Section 5.4(c).

(e) **Multiple DS Supply Agreements**. It is the intention of the Company and the DS Supplier that, in the event the DS Supplier is a party to other agreements with the Company for the provision of DS Supply that existed prior to the Effective Date of this Agreement or are entered into after the Effective Date of this Agreement, all such agreements may be considered, at the Company's reasonable discretion, to be in default, and the Company will calculate a single Termination Payment applicable to all such agreements as set forth herein.

5.5 Step-Up Provision

In the event of an early termination of a Default Service SMA between the Company and an entity other than the DS Supplier, the Company shall send a written notification to the DS Supplier which: (i) describes the individual supply obligations associated with the terminated transaction(s) for the remaining term(s) of such transaction(s); and (ii) requests the DS Supplier to agree to supply its full or partial amount of the supply obligation associated with each terminated transaction for the remaining term(s) of the terminated transaction(s), without change to the pricing, terms and conditions of the terminated Default Service SMA transaction(s). Such agreement to make additional supply available shall be termed a "Step-Up".

In the event that the DS Supplier wishes to exercise its option to Step-Up when such an opportunity arises, the DS Supplier shall respond to Company of such within five (5) Business Days from the date of Company's notification. In the DS Supplier's response, the DS Supplier shall indicate: (i) the maximum amount of the increased obligation that the DS Supplier wishes to take on given the additional supply obligation available from the terminated transactions (which need not be all); and (ii) that it is willing to meet any additional collateral requirements related to the Step-Up. The DS Supplier's response shall take place no later than five (5) Business Days of its receipt of the Company's notification. The amount of supply obligation assigned to the DS Supplier following the DS Supplier's Step-Up response will be the DS Supplier's pro-rata share of the total of such Step-Up responses from all DS Suppliers and will be from zero up to and including the maximum amount that the DS Supplier indicates. The DS Supplier's pro-rata share, as described in

this paragraph, shall be the ratio of the DS Supplier's amount indicated in the DS Supplier's Step-Up response, stated on a PLC basis, to the total of amounts indicated in all DS Suppliers' Step-Up responses. The Company will determine the DS Supplier's pro-rata share within six (6) Business Days from the date of the Company's initial notification. Once the Company has determined the DS Supplier's pro-rata share, the Company will forward electronically, by immediate means acceptable to both Parties, to the DS Supplier a partially executed Transaction Confirmation(s). By 2:00 p.m. Eastern Prevailing Time ("EPT") on the second Business Day following the DS Supplier's receipt of such partially executed Transaction Confirmation(s), the DS Supplier shall return electronically, by immediate means acceptable to both Parties, to the Company one (1) fully executed Transaction Confirmation(s).

For the avoidance of doubt, in the event that the DS Supplier does not respond to the Company's Step-Up request within the relevant timeframe, the DS Supplier shall be deemed to have rejected the Company's request in full.

5.6 Setoff of Payment Obligations of the Non-Defaulting Party

Any payment obligations of the Non-Defaulting Party to the Defaulting Party pursuant to this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply shall be set off: (i) first, to satisfy any payment obligations of the Defaulting Party to the Non-Defaulting Party pursuant to this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply that are unsecured and not subject to any Guaranty; (ii) second, to satisfy any payment obligations of the Defaulting Party to the Non-Defaulting Party pursuant to this

Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply that are unsecured, but which are subject to a Guaranty; and (iii) third, to satisfy any remaining payment obligations of the Defaulting Party to the Non-Defaulting Party pursuant to this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply.

5.7 Preservation of Rights of Non-Defaulting Party

The rights of the Non-Defaulting Party under this Agreement, including without limitation Sections 5.4 and 5.6 of this Agreement, shall be supplemental to, and not in lieu of, any right of recoupment, lien, or set-off afforded by applicable law, and all such rights are expressly preserved for the benefit of the Non-Defaulting Party.

(a) Duty to Mitigate – Each Party agrees that it has a duty to mitigate Damages and covenants that it will use commercially reasonable efforts to minimize any Damages it may incur as a result of the other Party's failure to perform pursuant to this Agreement.

(b) Return of Auction Revenue Rights – When the DS Supplier is the Defaulting Party, the DS Supplier will make best efforts to facilitate the transfer or reassignment to the entity which is the replacement DS Supplier on the Early Termination Date, any and all of the replacement DS Supplier's rights to ARRs to which the replacement DS Supplier is entitled as an LSE pursuant to the PJM Agreements, which were

transferred or assigned to the DS Supplier under Section 2.3 (Congestion and Congestion Management).

ARTICLE 6
CREDITWORTHINESS

6.1 Applicability

With respect to all Transactions under this Agreement and all other transactions for supply serving DS Load under other agreements executed between the Parties pursuant to the PaPUC Orders, if at any time and from time to time during the term of Transaction(s) under this Agreement, the Company's aggregate credit exposure to DS Supplier under this Agreement exceeds the Credit Limit on any Business Day, then the Company shall have the right to request that DS Supplier post performance assurance in an amount equal to the amount by which DS Supplier's aggregate exposure exceeds the Credit Limit (rounding upwards to the nearest $100,000), less any performance assurance already posted with the Company. The Company's request for performance assurance shall not be disputed by DS Supplier in the absence of manifest error.

6.2 Creditworthiness Determination

The DS Supplier may submit and maintain a security deposit in accordance with Section 6.4(e) of this Agreement in lieu of submitting to or being qualified under a creditworthiness evaluation. The DS Supplier shall have the opportunity to request that the Company re-evaluate its creditworthiness whenever an event occurs that the DS Supplier believes would improve the determination made by the Company of its

creditworthiness. The Company's credit re-evaluation must be completed as soon as possible but no longer than thirty (30) days after receiving a fully documented request. The Company must provide the rationale for its determination of the Credit Limit and any resulting security requirement. The Company must perform its credit re-evaluation and associated security calculation in a non-discriminatory manner. DS Supplier shall provide the Company and its agents unrestricted access to audited financial statements; provided that if audited financial statements are not available, the Company, in its reasonable discretion, may specify other types of financial statements that will be accepted.

6.3 Credit Exposure

(a) Fixed Price Transactions

To calculate the daily exposure for each DS Supplier for Fixed Price Transactions, the MtM credit exposure methodology will be used. For each Fixed Price Transaction, the "initial marks" for each Billing Month will be determined at the time the DS Solicitation is completed based on the available On-Peak Energy Forward Price and Off-Peak Energy Forward Price. At the time the DS Solicitation is completed, the MtM credit exposure for Fixed Price Transaction(s) arising from such DS Solicitation shall be equal to zero. Subsequently, the differences between (i) the available On-Peak Energy Forward Prices and Off-Peak Energy Forward Prices on the valuation date and (ii) the "initial mark" prices for the corresponding Billing Months will be used to calculate the daily credit exposures for each DS Supplier. The MtM Exposure Amount for a given Fixed Price Transaction will be equal to 1.1 times the sum of the MtM credit

exposures across all Billing Months of such Fixed Price Transaction minus amounts due pursuant to such Fixed Price Transaction to such DS Supplier for the delivery of DS Supply. The methodology for calculation of the MtM credit exposure on a per Tranche basis is illustrated in Appendix B hereto.

(b) Spot Market Transactions

Credit exposure for Spot Market Transactions shall be the product of $75,000 and the total number of Tranches awarded to DS Supplier for each Spot Market Transaction under this Agreement.

6.4 Credit Limit

The following criteria constitute the Company's creditworthiness requirements for the DS Supplier to cover the Total Exposure Amount. In all instances, the most current senior unsecured long-term debt rating (not supported by third-party credit enhancements, or, if unavailable, the most current corporate issuer rating) will be used.

(a) For a DS Supplier to be granted an unsecured line of credit, the DS Supplier must be rated by at least two of the following rating agencies: S&P, Moody's, or Fitch. The methodology for determining the credit rating to use is set forth in Appendix A of this Agreement. The Maximum Credit Limit to cover the Total Exposure Amount will be determined based on the credit matrix table in Appendix A of this Agreement.

(b) The DS Supplier will be required to post cash or a letter of credit in an

acceptable form as defined in Section 6.7(b) of this Agreement (see standard format in Exhibit 5) for the Margin due the Company as set forth in Section 6.5 of this Agreement.

(c) For a DS Supplier having a Guarantor, the Guarantor (i) must be rated by at least two of the following rating agencies: S&P, Moody's, or Fitch, and (ii) must have a minimum senior unsecured long-term debt rating (not supported by third-party credit enhancements, or, if unavailable, corporate issuer rating) equal to the Minimum Rating, as defined in Appendix A. If the Guarantor is rated by only two rating agencies, and the ratings are split, the rating will be established based on the methodology outlined in Appendix A of this Agreement. The Maximum Credit Limit to cover the Total Exposure Amount that could be provided through the Guaranty (see standard format in Exhibit 6) will be determined based on the credit matrix table for Guarantors on Appendix A. The DS Supplier will be granted a Credit Limit equal to the lesser of (i) the amount of the Guaranty as provided to the Company at the time this Agreement is executed as such amount may be modified in any amended or substitute Guaranty provided to the Company during the term of this Agreement, or (ii) the applicable Maximum Credit Limit as determined in Appendix A. The DS Supplier, however, may not increase or substitute its Guaranty for the purpose of increasing its applicable Credit Limit during the time period after the Company has made a Margin call, but before the DS Supplier has posted

the required performance assurance collateral as set forth in Section 6.7 to cover Margin. Notwithstanding anything herein to the contrary, the DS Supplier may increase the limit of its Guaranty after satisfying a Margin call from the Company, and upon the Company's receipt of an amended or substitute Guaranty increasing the limit of the Guaranty, the DS Supplier may request a return of the posted performance assurance collateral in accordance with Section 6.5 of this Agreement. The DS Supplier will be required to post cash or a letter of credit in an acceptable form as defined in Section 6.7(b) of this Agreement (see standard format in Exhibit 5) for the Margin due the Company as set forth in Section 6.5 of this Agreement.

(d) For a Guarantor that has not been incorporated or otherwise formed under the laws of the United States; in addition to the requirements set forth in 6.4(c), they shall supply the following additional information:

i. A legal opinion of counsel qualified to practice in the foreign jurisdiction in which the Guarantor is incorporated or otherwise formed that the Guaranty is, or upon completion of execution formalities will become, the binding obligation of the Guarantor in the jurisdiction in which it has been incorporated or otherwise formed;

ii. The sworn certificate of the corporate secretary (or similar officer) of such Guarantor that the person executing the Guaranty on behalf of the Guarantor has the authority to execute the Guaranty and that

the governing board of the Guarantor has approved the execution of the Guaranty;

iii. The sworn certificate of the corporate secretary (or similar officer) of such Guarantor that the Guarantor has been authorized by its governing board to enter into agreements of the same type as the Guaranty; and

iv. Such other documents and certificates as may be required by the Company in its reasonable discretion.

(e) If a DS Supplier chooses not to undertake a creditworthiness evaluation, it shall be required to post cash or a letter of credit for the Total Exposure Amount as set forth in Section 6.5 of this Agreement.

6.5 Posting Margin and Return of Surplus Margin

(a) If at any time and from time to time during the term of Transaction(s) under this Agreement, the Total Exposure Amount, rounded by the Rounding Amount, exceeds the DS Supplier's or the Guarantor's Credit Limit by the Minimum Transfer Amount, then the Company on any Business Day, may request that the DS Supplier provide cash or a letter of credit in an acceptable form as defined in Section 6.7(b) of this Agreement (see standard format in Exhibit 5), in an amount equal to the Margin (less any performance assurance collateral for Margin posted by the DS Supplier and held by the Company pursuant to this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply).

If the DS Supplier receives written notice for performance assurance collateral to cover Margin from the Company by 1:00 p.m. New York time on a Business Day, then the DS Supplier shall post the performance assurance collateral to cover Margin the next following Business Day, if posting cash, and by the second Business Day following the date of notice, if posting a letter of credit, unless the Company agrees in writing to extend the period to provide performance assurance collateral to cover Margin. If the DS Supplier receives notice for performance assurance collateral to cover Margin from the Company after 1:00 p.m. New York time on a Business Day, whether posting cash or a letter of credit, then the DS Supplier must post performance assurance collateral to cover Margin the second Business Day following the date of notice unless the Company agrees in writing to extend the period to provide performance assurance collateral to cover Margin. The Company will not unreasonably deny a request for a one-day extension of such period. In the event that the DS Supplier fails to post performance assurance collateral to cover Margin when due in accordance with this Section 6.5, then an Event of Default under Article 5 of this Agreement will be deemed to have occurred and the Company will be entitled to the remedies set forth in Article 5 of this Agreement.

(b) Surplus Margin being held by the Company that is not needed to satisfy the Total Exposure Amount, as determined above, will be returned to the DS

Supplier upon receipt of a written request by the DS Supplier. Surplus Margin means cash or a letter of credit posted by the DS Supplier as a result of a request by the Company pursuant to Section 6.5(a) that exceeds the Total Exposure Amount less the DS Supplier's or the Guarantor's Credit Limit (rounded by the Rounding Amount). If the resulting surplus Margin amount is more than the Minimum Transfer Amount, it will be returned to the DS Supplier. If the DS Supplier posted cash and notice is received by 1:00 p.m. New York time on a Business Day, the surplus Margin will be returned by the next following Business Day, and if the DS Supplier posted cash and notice is received by the Company after 1:00 p.m. New York time on a Business Day, the surplus Margin shall be returned by the second Business Day following the date of notice, unless the DS Supplier agrees in writing to extend the period to return the surplus Margin. If the DS Supplier posted a letter of credit, the surplus Margin shall be returned on the next Business Day following the Business Day on which the amendment to the letter of credit is received from the issuing bank, unless the DS Supplier agrees in writing to extend the period to return the surplus Margin. The DS Supplier will not unreasonably deny a request for a one-day extension of such period. In the event that the Company fails to return the surplus Margin when due in accordance with this Article, then an Event of Default under Article 5 of this Agreement will be deemed to have occurred and the

DS Supplier will be entitled to the remedies set forth in Article 5 of this Agreement.

6.6 Grant of Security Interest/Remedies

To secure its obligations under this Agreement and to the extent that the DS Supplier posted performance assurance collateral to cover Margin hereunder, the DS Supplier hereby grants to the Company a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, the Company, and the DS Supplier and the Company agree to take such action as is reasonably required to perfect the secured Party's first priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, the Company may do any one or more of the following: (i) exercise any of the rights and remedies of the Company with respect to all collateral, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the DS Supplier in the possession of the Company whether held in connection with this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply; (iii) draw on any outstanding letter of credit issued for its benefit; and (iv) liquidate all security held by or for the benefit of the Company free from any claim or right of any nature whatsoever of the DS Supplier, including any equity or right of purchase or

redemption by the DS Supplier. The Company shall apply the proceeds of the collateral realized upon the exercise of such rights or remedies to reduce the DS Supplier's obligation under this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply (the DS Supplier remaining liable for any amounts owing to the Company after such application), subject to the Company's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

All notices, demands or requests regarding credit requirements and credit related security or deposit transfers shall be in writing and shall be personally delivered or sent by overnight express mail, courier service or electronic transmission (with the original transmitted by any of the other aforementioned delivery methods) addressed as provided in Exhibit 3.

If to the Company to:

Attn: John Early – Manager, Credit and Contract Administration

220 West Main Street, Louisville, KY 40202

Copy to:

827 Hausman Rd., 1st Floor, Allentown, PA 18104

Notice received after the close of the Business Day shall be deemed received on the next Business Day; provided that notice by electronic transmission shall be deemed to have been received by the recipient if the recipient confirms receipt telephonically or in writing.

6.7 Security Instruments

At each DS Supplier's choice, the following are deemed to be acceptable methods for posting security to satisfy Margin requirements, if required:

(a) Cash; or

(b) A standby irrevocable letter of credit acceptable to the Company, in its reasonable discretion, issued by a bank or other financial institution with a minimum "A-" senior unsecured long-term debt rating (not supported by third-party credit enhancements, or, if unavailable, corporate issuer rating discounted one notch) from S&P and "A3" from Moody's. The letter of credit may be in a form that allows for electronic issuance and presentation of documents (see standard format, with provisions allowing for electronic issuance and presentation of documents, in Exhibit 5). The letter of credit shall state that it shall renew automatically for successive one-year or shorter periods, until terminated upon at least ninety (90) days prior written notice from the issuing financial institution. If the Company receives notice from the issuing financial institution that the letter of credit is being cancelled, the DS Supplier will be required to provide a substitute letter of credit from an alternative bank satisfying the minimum requirements. The receipt of the substitute letter of credit must be effective as of the cancellation date and delivered to the Company thirty (30) days before the cancellation date of the original letter of credit. If the DS Supplier fails to supply a substitute letter of credit as required, then the Company will have the right to draw on the existing letter of credit and to hold the amount as Margin.

(c) If the credit rating of a bank or other financial institution from which a DS

Supplier has obtained a letter of credit falls below the levels specified in Section 6.7(b) of this Agreement, the DS Supplier shall have two (2) Business Days following written notice by the Company to obtain a suitable letter of credit from another bank or other financial institution that meets those standards, unless such period is extended in writing by the Company. The Company shall have no obligation under this Agreement or otherwise to make or grant such extension.

6.8 Maintenance of Creditworthiness

(a) Reporting of Changes.

The DS Supplier shall promptly notify the Company within three (3) Business Days of any change in its credit rating or financial condition or that of its Guarantor. The DS Supplier or Guarantor shall also furnish evidence of an acceptable credit rating or financial condition upon the Company's request.

(b) Change in Credit Standing.

The Company will re-evaluate the creditworthiness of a DS Supplier whenever it becomes aware of an adverse change, through the provision of notice by the DS Supplier or otherwise, in the DS Supplier's or Guarantor's credit standing. If the lowest credit rating (whether senior unsecured debt rating or corporate issuer rating) used to determine the DS Supplier's Maximum Credit Limit or its Credit Limit adversely changes, the Company will require additional security from the DS Supplier in accordance with Section 6.5 of this Agreement. The additional security must be in a form acceptable to the Company in its reasonable discretion, as

specified in Section 6.7 of this Agreement and must be posted as set forth in Section 6.5 of this Agreement.

6.9 Calling on Security

The Company may call upon the security posted by the DS Supplier if the DS Supplier fails to pay amounts due to the Company pursuant to this Agreement or any other agreement(s) between the Company and the DS Supplier for the provision of DS Supply after all of the following events occur:

(a) Written Notice of Default is provided to the DS Supplier; and

(b) Any applicable cure period associated with the written Notice of Default ends.

The foregoing notwithstanding, the security posted by the DS Supplier shall become due automatically without prior notice or right of cure in the case of any Event of Default arising under subsections (a), (d), (e), (f), (g), (h), (i), and (j) of Section 5.1 of this Agreement.

6.10 Interest on Cash Held by Company

The Company will pay simple interest calculated at the Interest Index on all cash held by the Company pursuant to this Agreement. Each Billing Month, the Company will prepare a statement of interest amounts due to the DS Supplier. The statement will be sent to the DS Supplier within three (3) Business Days after the end of the Billing Month via overnight mail or other expeditious means. The Company shall make interest payments on the first Business Day after the 5th day of each calendar month**.**

6.11 No Endorsement of DS Supplier

The Company's determination that a DS Supplier is creditworthy pursuant to the process set forth above, shall not be deemed to constitute an express or implied warranty or guarantee of any kind with respect to the financial or operational qualifications of the DS Supplier. The Company will treat all DS Suppliers in a non-discriminatory manner and shall provide no preference to any DS Supplier.

6.12 Multiple Supply Agreements for Default Service

It is the intention of the Company and the DS Supplier that, in the event the DS Supplier is a party to other agreements with the Company for the provision of DS Supply that existed prior to the Effective Date of this Agreement, the Company will calculate the Margin applicable to all such agreements based upon the terms and conditions of the applicable agreements.

ARTICLE 7
PROCEDURES FOR ENERGY SCHEDULING, CAPACITY RESOURCE SUBMISSION AND TRANSMISSION PROCUREMENT

7.1 Load Obligations

The Company and the DS Supplier acknowledge and agree that (1) the Company shall determine the DS Load, (2) the Company shall allocate the DS Supply obligation using the DS Supplier Responsibility Share, (3) the Company shall provide the DS Supplier's DS Supply obligation to PJM, and (4) the DS Supplier shall be responsible for

meeting its DS Supply obligations as an LSE under the PJM Agreements.

7.2 Data Transmission

The procedures for transmitting load obligation data to PJM for the DS Supplier's DS Load shall be as set forth by PJM.

7.3 Energy Scheduling

The Company is not obligated to provide any day ahead scheduling services. If the Company chooses to provide such services, the information provided is not guaranteed by the Company.

ARTICLE 8
THE ENERGY SETTLEMENT/RECONCILIATION PROCESS

8.1 Energy Settlement By PJM

The settlement process occurs at PJM to reflect the DS Supplier's actual Energy obligations in a supply/usage reconciliation process. The Energy obligations for each DS Supplier will be determined based on the DS Supplier Responsibility Share of the DS Load. The reconciled total DS Supply obligation will be based on the final total Energy loads for the Customers receiving Default Service, including deration adjustments for marginal losses.

Any adjustments for billing and metering errors reported subsequent to the calculation of FMEA will be proportionally allocated by the Company to the DS Suppliers based on the respective DS Supplier Responsibility Share.

8.2 Energy Settlement by the Company

In the event that actual DS Customer consumption data is not available until after the PJM deadline for conducting the final settlement, the Company will conduct the settlement process with the DS Supplier. In the event PJM imposes penalties against the Company as a result of the DS Supplier's Transactions or failure to meet PJM requirements, such penalties shall be passed through by the Company to the DS Supplier as part of this settlement process as well as any costs and attorneys' fees incurred by the Company on account of or related to such penalties. In addition, all other applicable charges from PJM, including any billing adjustments, will be appropriately allocated to the DS Supplier.

ARTICLE 9
BILLING AND PAYMENT

9.1 The Company Payment of Obligations to the DS Supplier

The Company shall pay all amounts due to the DS Supplier hereunder in accordance with the following provisions. Unless specified otherwise, the following provisions apply to both Fixed Price Transactions and Spot Market Transactions. Specifically:

(a) Fixed Price Transactions:

(i) With respect to each Fixed Price Transaction, for each Billing Month, the Company will prepare a Statement of amounts due to the DS Supplier. This Statement will show the aggregate amounts due based on the DS Fixed Price indicated in such Transaction Confirmation multiplied by the PMEA of the Billing Month.

(ii) With respect to each Fixed Price Transaction, to the extent that the FMEA differs from the PMEA, the Company shall pay or charge the DS Supplier for the PMEA/FMEA Adjustment Amount within the PJM deadline for conducting the final settlement.

(b) Spot Market Transactions:

(i) With respect to each Spot Market Transaction, for each Billing Month, the Company will prepare a Statement of amounts due to the DS Supplier. This Statement will show the amounts due the DS Supplier, equal to the sum of: (a) an energy charge equal to sum of the products of each hour's load weighted, real-time spot market energy price for the Delivery Point, and the PHEA in each hour of the Billing Month, (b) a capacity charge equal to the sum of the product of the PJM Final Zonal Net Load Price for the Delivery Point in $/MW-day and the daily amounts of Capacity reported as the DS Supplier's Capacity obligation by Buyer to PJM for each day of the Billing Month; and (c) the product of the DS Fixed Price and the PMEA.

(ii) With respect to each Spot Market Transaction, to the extent that the FMEA differs from the PMEA, the Company shall pay or charge the DS Supplier for the PMEA/FMEA Adjustment Amount within the PJM deadline for conducting the final settlement. The PMEA/FMEA Adjustment Amounts apply only to payments

unrelated to the energy charge or capacity charge as described in Section 9.1(b)(i) above.

(iii) With respect to each Spot Market Transaction, to the extent that the FHEA differs from the PHEA, the Company will calculate the PHEA/FHEA Adjustment Amount for each hour by multiplying the difference between the two amounts by the load weighted, real-time spot market energy price for the Delivery Point, and will sum the negative and positive dollar values over all hours to arrive at a net PHEA/FHEA Adjustment Amount for the Billing Month. Based on the calculated net PHEA/FHEA Adjustment Amount, the Company will pay or charge the DS Supplier for such billing adjustments within the PJM deadline for conducting the final settlement.

(iv) With respect to each Spot Market Transaction, to the extent that the daily Capacity obligations used in the calculation detailed in Section 9.1(b)(i) are adjusted, the Company will pay or charge the DS Supplier any net difference between the payment made and the payment calculated using the adjusted values. For avoidance of doubt, the MW of Capacity reported as DS Supplier's Capacity obligation shall be adjusted for any subsequent meter corrections reported to PJM, or as a result of any subsequent retail load settlement process. Any reduction in load as a result of Buyer's or PJM's operation of its load response programs shall be reflected as

a reduction in the MW of Capacity.

(c) General Provisions:

(i) The Statement(s) will be sent to the DS Supplier within eight (8) Business Days after the end of the Billing Month via overnight mail or other expeditious means.

(ii) The Company shall make payment on the first Business Day after the 19th day of each calendar month.

(iii) If each Party owes an amount to the other Party pursuant to this Agreement, including any related interest, payments or credits, the Parties may satisfy their respective obligations to each other by netting the aggregate amounts due to one Party against the aggregate amounts due to the other Party, with the Party, if any, owing the greater aggregate amount paying the other Party the difference between the amounts owed.

(iv) Payments shall be subject to adjustment for any arithmetic errors, computation errors, meter reading errors, or other errors, provided that the errors become known within one (1) year of the termination of all Transactions under this Agreement.

(v) The Company shall make payments of funds payable to the DS Supplier by electronic transfer to a bank designated by the DS Supplier.

(vi) If a good faith dispute arises between the Company and the DS

Supplier regarding a Statement, the disputing Party shall be obligated to pay only the undisputed portion of the Statement, if any, and shall present the dispute in writing and submit supporting documentation to the non-disputing Party within one hundred twenty (120) calendar days from the date of the Statement in dispute. Statement disputes shall be addressed promptly, and in accordance with the dispute resolution procedures set forth in Article 11 (Dispute Resolution) of this Agreement. Upon resolution of a Statement dispute, any payments made to either Party will include simple interest on the payment at the lower of the Interest Index or six (6) percent per annum payable from the date that notice of a Statement dispute was received by the non-disputing Party.

(vii) If payment is made to the DS Supplier after the due date shown on the Statement, a late fee will be added to the unpaid balance until the entire Statement is paid. This late fee shall be the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) or (b) the maximum rate permitted by applicable law.

(viii) If DS Supplier has entered into more than one Transaction with Buyer, DS Supplier shall receive a single Statement listing the

relevant information detailed above.

9.2 Billing for DS Supplier's Obligations to Other Parties

Except as set forth in Sections 2.5 and 2.6, the Company shall have no responsibility for billing between the DS Supplier and PJM; the DS Supplier and any Energy or Capacity source; or the DS Supplier and any other third party. The Company will be solely responsible for billing DS Customers for Default Service.

9.3 The DS Supplier Payment of Obligations to the Company

The DS Supplier shall pay all Charges it incurs hereunder in accordance with the following provisions:

(a) Each Billing Month, the Company shall submit an invoice to the DS Supplier for all Charges owed by the DS Supplier under this Agreement. The DS Supplier shall make payment for Charges shown on the invoice. The due date will be on the first Business Day after the 19th day of each calendar month. The invoice will be sent to the DS Supplier within eight (8) Business Days after the end of the Billing Month via overnight mail or other expeditious means.

(b) Invoices shall be subject to adjustment for any arithmetic errors, computation errors, meter reading errors, or other errors, provided that the errors become known within one (1) year of the termination of all Transactions of this Agreement.

(c) The DS Supplier shall make payments of immediately available funds

payable to the Company by electronic transfer to a bank designated by the Company.

(d) If a good faith dispute arises between the Company and the DS Supplier regarding an invoice, the disputing Party shall be obligated to pay only the undisputed portion of the invoice, if any, and shall present the dispute in writing and submit supporting documentation to the non-disputing Party within one hundred twenty (120) calendar days from the due date of the invoice in dispute. Billing disputes shall be addressed promptly, and in accordance with the dispute resolution procedures set forth in Article 11 of this Agreement. Upon resolution of a billing dispute, any payments made to either Party will include simple interest on the payment at the lower of the Interest Index or six (6) percent per annum payable from the date that notice of a bill dispute was received by the non-disputing Party.

(e) If payment is made to the Company after the due date shown on the invoice, a late fee will be added to the unpaid balance until the entire invoice is paid. This late fee shall be the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under “Money Rates” on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) or (b) the maximum rate permitted by applicable law.

ARTICLE 10
SYSTEM OPERATION

The Parties shall adhere to any applicable operational requirements of PJM necessary to protect the integrity of the transmission system within the PJM Control Area and the transmission systems of interconnected control areas, and shall satisfy any and all PJM, RFC and NERC criteria, when applicable. The DS Supplier shall also adhere to any applicable operational requirements of the Company necessary to protect the integrity of the Company's local distribution system.

10.1 Disconnection and Curtailment By the Company

The Company shall have the right, without incurring any liability to the DS Suppliers, to disconnect (or otherwise curtail, interrupt or reduce deliveries from) the DS Suppliers or to disconnect (or otherwise curtail, interrupt or reduce deliveries to) any Customer whenever the Company determines in the exercise of its good faith discretion, or when the Company is directed by PJM, that such a disconnection, curtailment, interruption or reduction is necessary to facilitate construction, installation, maintenance, repair, replacement or inspection of any of the Company's facilities; or due to any other reason affecting the safe and reliable operation of the Company's or a Customer's facilities, including, without limitation, an Emergency, forced outage or potential overloading of the Company's transmission and/or distribution circuits, potential damage to any Customer's facilities or any risk of injury to persons or property.

10.2 Inadvertent Loss of Service to DS Customers

The Parties agree and acknowledge that service to DS Customers may be

inadvertently lost due to storms, weather, accidents, breakage of equipment or other events beyond the reasonable control of the Company affecting the transmission and distribution system of the Company. Neither Party will have any liability to the other Party for the occurrence of such events. In no event will an inadvertent loss of service affect a Party's obligation to make any payments then due or becoming due with respect to performance rendered prior to such inadvertent loss of service.

10.3 PJM Requirements

The DS Supplier acknowledges and agrees that, as a member of PJM, the Company is bound by all PJM operating instructions, policies and procedures as are currently set forth in the PJM Operating Manual, which are available through the Internet on the PJM Home Page (http://www.pjm.com), as may be revised from time to time, which are needed to maintain the integrity of the PJM system. The DS Supplier acknowledges and agrees that it will cooperate with the Company so that the Company will be in compliance with all PJM Emergency Operations Procedures, which include, but are not limited to, those procedures pertaining to minimum and maximum generation Emergencies, and measures requiring involuntary Customer participation, such as supply voltage reduction or full interruption of Customer load by either manual or automatic means.

10.4 Compliance With Governmental Directives

The DS Supplier also acknowledges and agrees that the Company may need to act in response to governmental or civil authority directives which may affect DS Load. The DS Supplier agrees to cooperate with the Company in order to comply with said directives.

ARTICLE 11
DISPUTE RESOLUTION

11.1 Informal Resolution of Disputes

Before pursuing resolution of any dispute arising out of this Agreement (other than an Event of Default under Section 5.1 (a), (d), (e), (f), (g), (h), (i), and (j), and as a condition precedent thereto, the disputing Party shall provide written notice to the other Party setting forth the nature of the dispute, the amount involved, if any, and the remedies sought. The Parties shall use good faith and reasonable commercial efforts to informally resolve such dispute. Such efforts shall last for a period of at least thirty (30) calendar days from the date that the notice of the dispute is first delivered from one Party to the other Party. Any amounts that are owed by one Party to the other Party as a result of resolution of a dispute pursuant to this Section 11.1 (Informal Resolution of Disputes), shall be paid within two (2) Business Days of such resolution and the payment shall include interest calculated at the Interest Index from the original due date through the date of payment.

11.2 Recourse to Agencies or Courts of Competent Jurisdiction

After the condition precedent requirements of Section 11.1 (Informal Resolution of Disputes) have been satisfied, all unresolved disputes, except as noted below, between the Parties shall be submitted to the appropriate authority as set forth in Section 16.5 of this Agreement. Nothing in this Agreement shall restrict the rights of either Party to file a complaint with the FERC under relevant provisions of the Federal Power Act ("FPA") or with the PaPUC under relevant provisions of the Applicable Legal Authorities. The Company, but not the DS Supplier, may also elect, in its sole discretion, to pursue its

remedies in the Lehigh County Court of Common Pleas, or the Eastern District Court of Pennsylvania in Allentown subject to Section 16.5 of this Agreement. A Party's agreement hereunder is without prejudice to any Party's right to contest the jurisdiction of the FERC or the PaPUC to which a complaint is brought, however, should the Company elect to commence a court proceeding, the DS Supplier hereby consents to the jurisdiction of the Lehigh County Court of Common Pleas, or the Eastern District Court of Pennsylvania and waives all rights to contest the Company's election to proceed in such court whether based on forum non conveniens or otherwise.

The Parties hereby acknowledge and agree that both Parties entered into this Agreement and all Transactions under this Agreement freely and in good faith, both had the opportunity to have counsel review the Agreement, and agree that the terms of this Agreement have not been affected in any way, either directly or indirectly, by (A) any fraud, duress, unfairness, or any inequity in the relative bargaining power of the Parties or (B) any manipulation, unlawful activity, disruption, anomaly, dysfunction, or other adverse market conditions of any type or description.

To the extent permitted by law and absent agreement to the contrary, each Party, for itself and its successors and assigns, hereby expressly and irrevocably waives its rights to argue before any governmental authority that any review, modification, or rescission of this Agreement should be considered under any standard of review other than the "public interest" standard set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956)* and *Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956),* affirmed by *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of*

Snohomish County, Washington, et al., 554 U.S. 527 (2008) (the "Mobile-Sierra Doctrine").

ARTICLE 12
REGULATORY AUTHORIZATIONS AND JURISDICTION

12.1 Compliance With Applicable Legal Authorities

The Company and the DS Supplier are subject to, and shall comply with, all existing or future applicable federal, state and local laws, all existing or future duly-promulgated orders or other duly-authorized actions of PJM or of Applicable Legal Authorities.

12.2 FERC Jurisdictional Matters

The inclusion herein of descriptions of procedures or processes utilized by PJM or otherwise subject to the jurisdiction of the FERC is intended solely for informational purposes. If anything stated herein is found by the FERC to conflict with or be inconsistent with any provision of the FPA, or any rule, regulation, order or determination of the FERC under the FPA or if any existing procedures or processes utilized by PJM are duly modified, the applicable FERC rule, regulation, order, determination or modification shall control. To the extent required under any provision of the FPA, or any rule, regulation, order or determination of the FERC under the FPA, the Company and/or the DS Supplier, if applicable, shall use reasonable commercial efforts to secure, from time to time, all appropriate orders, approvals and determinations from the FERC necessary to support this Agreement.

12.3 Energy Efficiency, Conservation, and Retail Market Programs

DS Supplier acknowledges that DS Customers may participate in new or existing energy efficiency and conservation programs, and retail market programs offered by the Company (required by Applicable Legal Authorities or otherwise offered by the Company whether voluntarily or not), by PJM, or by other third parties, and that such participation may reduce or change the amount of DS Supply that DS Supplier is required to provide and the amount of monies it may receive under this Agreement. The Company shall have no obligation whatsoever to DS Supplier with respect to the effect, if any, of such programs. DS Supplier is solely responsible for determining the effect, if any, of such programs on future load requirements.

ARTICLE 13
LIMITATION OF REMEDIES, LIABILITY AND DAMAGES

13.1 Limitations on Liability

Except as set forth in this Agreement, there is no warranty of merchantability or fitness for a particular purpose, and any and all implied warranties are disclaimed. The Parties confirm that the express remedies and measures of Damages provided in this Agreement satisfy the essential purposes hereof. For breach of any provision for which an express remedy or measure of Damages is provided, such express remedy or measure of Damages shall be the sole and exclusive remedy, the obligor's liability shall be limited as set forth in such provision and all other remedies or Damages at law or in equity are waived. If no remedy or measure of Damages is expressly provided herein, the obligor's liability shall be limited to direct actual Damages only, such direct actual Damages shall be the sole

and exclusive remedy and all other remedies or Damages at law or in equity are waived. Unless expressly herein provided, neither Party shall be liable for consequential, special, incidental, punitive, exemplary or indirect Damages, lost profits, loss of financing, business or reputation or other business interruption Damages, by statute, in tort or contract, under any indemnity provision or otherwise. It is the intent of the Parties that the limitations herein imposed on remedies and the measure of Damages be without regard to the cause or causes related thereto, including the negligence or any Party, whether such negligence by sole, joint or concurrent, or active or passive. To the extent any Damages required to be paid hereunder are liquidated, the Parties acknowledge that the Damages are difficult or impossible to determine, or otherwise obtaining an adequate remedy is inconvenient and it is agreed that the Damages calculated hereunder constitute a reasonable approximation of the harm or loss.

13.2 Risk of Loss

Solely for purposes of determining risk of loss and for determining the indemnity obligations under Article 14 of this Agreement, the Company shall be deemed to have custody and control of the electric Energy delivered by the DS Supplier upon receipt thereof into the Company's distribution system and until delivery thereof at the retail electric meter of the Customer; and the DS Supplier shall be deemed to have custody and control of the DS Supply at all times prior to receipt thereof by the Company. The Party deemed to have custody and control of DS Supply shall be responsible for all loss or damage to property or injury or death to persons arising in connection with such DS Supply

while in its custody and control and shall indemnify the other Parties with respect to same as set forth in Article 14 of this Agreement.

ARTICLE 14
INDEMNIFICATION

14.1 Indemnification

(a) Should the Company become the defendant in, or obligor for, any third party claims and/or liabilities for losses, penalties, expenses, damage to property, injury to or death of any person including a Party's employees or any third parties, that were caused by or occur in connection with an act or omission of the DS Supplier with respect to an obligation arising under or in connection with this Agreement, or for which the DS Supplier has otherwise assumed liability under the terms of this Agreement, the DS Supplier shall defend (at the Company's option), indemnify and hold harmless the Company, and its Affiliates, its shareholders, board members, directors, officers and employees, agents, contractors, subcontractors, invitees, successors, representatives, and permitted assigns from and against any and all such third party claims and/or liabilities, and shall appoint counsel at DS Supplier's expense, subject to the approval of Company, to defend any such claims or liabilities, except in the event of and to the extent that a final determination by a court of competent jurisdiction determines that the losses, penalties, expenses or damages were caused wholly or in part by the gross negligence or willful misconduct of the Company. The

Company may, at its own expense, retain counsel and participate in the defense of any such suit or action.

(b) Should the DS Supplier (the "Indemnified DS Supplier") become the defendant in, or obligor for, any third party claims and/or liabilities for losses, penalties, expenses, damage to property, injury to or death of any person including a Party's employees or any third parties, that were caused by or occur in connection with an act or omission of the Company with respect to an obligation arising under or in connection with this Agreement, or for which the Company has otherwise assumed liability under the terms of this Agreement, the Company shall defend (at the option of the Indemnified DS Supplier), indemnify and hold harmless the Indemnified DS Supplier, its shareholders, board members, directors, officers and employees, from and against any and all such third party claims and/or liabilities, except in the event of and to the extent that a final determination by a court of competent jurisdiction determines that the losses, penalties, expenses or damages were caused wholly or in part by the gross negligence or willful misconduct of the Indemnified DS Supplier. The Indemnified DS Supplier may, at its own expense, retain counsel and participate in the defense of any such suit or action.

(c) If either Party intends to seek indemnification under Section 14.1(a) or Section 14.1(b), as applicable, from the other Party, the Party seeking indemnification shall give the other Party notice of such claim within ninety

(90) days of the later of the commencement of, or the Party's actual knowledge of, such claim or action. Such notice shall describe the claim in reasonable detail, and shall indicate the amount, estimated if necessary, of the claim that has been, or may be, sustained by said Party. To the extent that the other Party will have been actually and materially prejudiced as a result of the failure to provide such notice, such notice will be a condition precedent to any liability of the other Party under the provisions for indemnification contained in this Agreement. Neither Party may settle or compromise any claim without the prior consent of the other Party; provided, however, said consent shall not be unreasonably withheld, conditioned or delayed.

(d) In the event that a Party fails or refuses to indemnify an indemnitee hereunder, in addition to all other obligations and upon adjudication in favor of an indemnitee, the indemnitor shall be responsible for any and all costs associated with bringing such action, including but not limited to attorneys' fees and costs.

14.2 Survives Agreement

The obligation of a Party to defend, indemnify, and hold harmless another Party under this Article 14 (Indemnification) shall survive termination of this Agreement, and as such obligation relates to claims asserted by employees of the indemnified party or otherwise, shall not be limited in any way by any limitation on the amount or type of damages, compensation or benefits payable by or for either Party under any statutory

scheme, including any workers' compensation acts, disability benefit acts or other employee benefit acts and both Parties hereby waive any and all immunities or statutory protections under any workers' compensation act or similar statute.

ARTICLE 15
FORCE MAJEURE

15.1 Force Majeure

Notwithstanding anything in this Agreement to the contrary, the Parties shall be excused from performing their respective obligations under this Agreement (other than the obligation to make payments with respect to performance prior to the event of Force Majeure) and shall not be liable for damages or otherwise due to their failure to perform, during any period that one Party is unable to perform due to an event of Force Majeure, provided that the Party declaring an event of Force Majeure shall: (i) act expeditiously to resume performance; (ii) exercise all commercially reasonable efforts to mitigate or limit damages to the other Party; and (iii) fulfills the requirements set forth in Section 15.2 (Notification).

15.2 Notification

A Party unable to perform under this Agreement due to an event of Force Majeure shall: (i) provide prompt written notice of such event of Force Majeure to the other Party, which shall include an estimate of the expected duration of the Party's inability to perform due to the event of Force Majeure; and (ii) provide prompt notice to the other Party when performance resumes.

ARTICLE 16
MISCELLANEOUS PROVISIONS

16.1 Notices

Unless otherwise stated herein, all notices, demands or requests required or

permitted under this Agreement other than legal communications shall be in writing and shall be personally delivered or sent by email, overnight express mail or courier service. Any legal communications shall be in writing and shall be personally delivered or sent by email, overnight express mail or courier service, provided that any legal communications sent via email transmission must also be transmitted by overnight express mail or courier service. All notices and communications must be addressed per the notification information for the DS Supplier and Company as set forth in Exhibit 3 hereto.

Such notices, demands or requests shall also be provided to such other person at such other address as a Party may designate by like notice to the other Party. Notice received after the close of the Business Day shall be deemed received on the next Business Day.

16.2 No Prejudice of Rights

The failure of a Party to insist on any one or more instances upon strict performance of any provisions of this Agreement, or to take advantage of any of its rights hereunder, shall not be construed as a waiver of any such provisions or the relinquishment of any such right or any other right hereunder, which shall remain in full force and effect. No term or condition of this Agreement shall be deemed to have been waived and no breach excused unless such waiver or consent to excuse is in writing and signed by the Party claimed to have waived or consented to excuse.

16.3 Effect of Regulatory or Legislative Actions

(a) The Parties agree that the Company's obligations under this Agreement are contingent on, and limited by, the Company's ability to recover all costs

incurred by it under this Agreement from its retail customers in full and on a current basis. If any statutes, rules, regulations, or orders are enacted, amended, entered, or revoked which have the effect of depriving the Company's full and current recovery of said costs, the Company may terminate this Agreement upon ten (10) days written notice. The Parties agree that any such termination shall not constitute an Event of Default under this Agreement.

(b) If any statutes, rules, regulations, or orders are enacted, amended, entered, or revoked which transfers the Company's obligation to procure or supply DS Supply to third party, this Agreement may be transferred to such third party in accordance with the provisions of Section 16.4 below. The Parties agree that any such transfer shall not constitute an Event of Default under this Agreement.

(c) In the event that this Agreement is terminated as a result of any of the reasons set forth in subsections (a) and (b) of Section 16.3 above, the Parties agree that the Company shall not be liable for any costs or damages incurred or otherwise associated with (i) the transfer of the Company's obligation to obtain or provide DS Supply to third party, or (ii) the elimination of the Company's obligation to obtain or provide DS Supply.

16.4 Assignment

The Parties shall not assign any of their rights or obligations under this Agreement without obtaining the prior written consent of the non-assigning Party, which consent shall

not be unreasonably withheld. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement until such obligations have been assumed by the assignee and all necessary consents have been obtained. Any assignment in violation of this Section 16.4 shall be void; provided, however, the Company may assign any or all of its rights and obligations under this Agreement notwithstanding anything contained herein to the contrary, without the DS Supplier's consent, to any entity succeeding to all or substantially all of the assets of the Company, or to a third party in accordance with 16.3(b), if such assignee agrees, in writing, to be bound by all of the terms and conditions hereof and all necessary regulatory approvals are obtained. The DS Supplier may, with prior written notice to the Company but without obtaining the approval of the Company, assign the accounts, revenues or proceeds under this Agreement to a third party. The Company agrees that, following receipt of such notice of the assignment of accounts, revenues or proceeds and such other documentation that the Company may reasonably request, the Company will pay amounts becoming due to the assigning DS Supplier under this Agreement directly to the designated assignee; provided, however, that nothing herein shall enlarge or expand the rights of such designated assignee beyond the rights granted to the DS Supplier and the right of such designated assignee to receive payments shall be subject to all defenses, offsets and claims of the Company arising under this Agreement.

16.5 Governing Law and Venue/Forum Selection

To the extent not subject to the jurisdiction of the FERC, questions including those concerning the formation, validity, interpretation, execution, amendment, termination and

construction of this Agreement shall be governed by the laws of the Commonwealth of Pennsylvania, without regard to principles of conflicts of law. Except for matters jurisdictional to the FERC, the Parties agree that all disputes relating to formation, validity, interpretation, execution, amendment, termination and construction of this Agreement not satisfied or resolved under the required resolution provisions of Section 11.1 of this Agreement shall be submitted to the PaPUC for determination, unless the Company, at its sole discretion, elects to submit any such dispute hereunder to the Lehigh County Court of Common Pleas, or the Eastern District Court of Pennsylvania in Allentown. AS A MATERIAL INDUCEMENT TO EACH PARTY TO ENTER INTO THIS AGREEMENT, IF THE DS SUPPLIER ELECTS TO PROCEED IN A COURT TO RESOLVE A DISPUTE, THE PARTIES EACH HEREBY IRREVOCABLY WAIVE ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR RELATING HERETO, ANY PRODUCT OR THE TRANSACTIONS CONTEMPLATED HEREBY. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

16.6 Regulatory Approvals

DS Supplier agrees to cooperate, to the fullest extent necessary, to obtain any and all required State, Federal or other regulatory approvals of the Agreement and/or Transaction Confirmations hereunder. The commencement of the Delivery Period of each Transaction and the obligations hereto are subject to (i) the receipt or waiver by Company

of all Company required regulatory approvals, (ii) the receipt or waiver by DS Supplier of all DS Supplier required regulatory approvals, and (iii) PaPUC approval.

16.7 Headings

The headings and subheadings contained in this Agreement are used solely for convenience and do not constitute a part of the Agreement between the Parties hereto, nor should they be used to aid in any manner in the construction of this Agreement.

16.8 Third Party Beneficiaries

This Agreement is intended solely for the benefit of the Parties hereto and nothing in this Agreement shall be construed to create any duty, or standard of care with reference to, or any liability to, any person not a Party to this Agreement.

16.9 General Miscellaneous Provisions

(a) This Agreement shall not be interpreted or construed to create an association, joint venture, or partnership between the Parties, or to impose any partnership obligation or liability upon any Party. No Party shall have any right, power, or authority to enter into any agreement or undertaking for, or on behalf of, or to act as or be an agent or representative of, or to otherwise bind, any other Party.

(b) Cancellation, expiration or Early Termination of this Agreement shall not relieve the Parties of obligations that by their nature survive such cancellation, expiration or termination, including warranties, remedies, promises of indemnity and confidentiality.

(c) Should any provision of this Agreement be held invalid or unenforceable, such provision shall be invalid or unenforceable only to the extent of such invalidity or unenforceability without invalidating or rendering unenforceable any other provision hereof unless it materially changes the agreement of the Parties; provided that in such event the Parties shall use commercially reasonable efforts to amend this Agreement or any Transaction in order to give effect to the original intention of the Parties.

(d) Each of the Parties acknowledges that it has read this Agreement, understands it, and agrees to be bound by its terms. This Agreement is intended by the Parties as a final expression of their agreement. The Parties further agree that this Agreement is the complete and exclusive statement of agreement and supersedes all proposals (oral or written), understandings, representations, conditions, warranties, covenants and all other communications between the Parties relating thereto. In the case of an actual or apparent inconsistency between this Agreement and the PPL Electric Utilities Corporation Default Service Request for Proposals Process and Rules ("RFP"), the provisions of this Agreement shall control. This Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against one Party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. Each Party further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is

inconsistent with this Agreement or any Transaction.

16.10 Taxes

As between the Parties: (i) the DS Supplier is responsible for the payment of all taxes imposed by all present and future federal, state, municipal or other taxes imposed by any taxing authority on the wholesale sales of DS Supply under this Agreement; and (ii) the Company is responsible for the payment of all taxes imposed by all present and future federal, state, municipal or other taxes imposed by any taxing authority on retail sales of DS Supply. Should the DS Supplier be required to remit any Pennsylvania State sales and use taxes directly to the applicable taxing authority, other than taxes previously collected by the DS Supplier on behalf of the Company, the Company will defend and indemnify the DS Supplier for such sales and use taxes and will pay to the DS Supplier all such tax amounts upon demand. If any Transaction is exempt from the payment of any sales and use taxes as defined above, the affected DS Supplier will, if requested, provide the Company with valid tax exemption certificates. Should the Company be required to remit any sales and use taxes directly to any applicable taxing authority, other than taxes previously collected by the Company directly from the DS Supplier, the DS Supplier will defend and indemnify the Company and will pay to the Company all applicable sales and use tax amounts upon demand.

16.11 Disclosure of Tax Treatment

Notwithstanding anything to the contrary in this Agreement or in the RFP and appendices thereto, DS Supplier and Company agree that: (i) any obligation of

confidentiality with respect to the Parties' Transactions hereunder does not apply, and has not applied from the commencement of discussions between the Parties, to the tax treatment and tax structure of the Agreement and all Transactions thereunder, and (ii) DS Supplier and Company (and each of their respective employees, representatives, or agents) may disclose to any and all persons, without limitation of any kind, the tax treatment and tax structure of the Agreement and the Transactions thereunder, as well as any materials of any kind (including opinions or other tax analyses) that have been provided to the disclosing Party relating to such tax treatment and tax structure, all within the meaning of Treasury Regulations Section 1.6011-4; provided, however, that the foregoing is not intended to affect any privileges that each Party is entitled, at its reasonable discretion, to maintain, including with respect to any confidential communications with its attorney or any confidential communications with a federally authorized tax practitioner under Section 7525 of the Internal Revenue Code.

16.12 Audit

Each Party has the right on at least three (3) Business Days prior written notice, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made in accordance with Article 9 (Billing and Payment) of this Agreement.

16.13 Rules of Interpretation

The following principles shall be observed in the interpretation and construction of this Agreement:

(a) Unless otherwise stated, the terms “include” and “including” when used in this Agreement shall be interpreted to mean by way of example only and shall not be considered limiting in any way;

(b) References to the singular include the plural and vice versa;

(c) References to Articles, Sections, Clauses and the Preamble are, unless the context indicates otherwise, references to Articles, Sections, Clauses and the Preamble of this Agreement;

(d) In carrying out its rights, obligations and duties under this Agreement, each Party shall have an obligation of good faith and fair dealing; and

(e) If any payment due under this Agreement would be, by operation of the terms and conditions of any provision hereof, due and payable on a day other than a Business Day, such payment shall be made on the next following Business Day.

16.14 Confidentiality

(a) Each Party shall hold in confidence and not release or disclose any document or information furnished by the other Party in connection with

this Agreement, unless: (i) compelled to disclose such document or information by judicial, regulatory or administrative process or other provisions of law; (ii) such document or information is generally available to the public; (iii) such document or information was available to the receiving Party on a non-confidential basis; (iv) such document or information was available to the receiving Party on a non-confidential basis from a third-party, provided that the receiving Party does not know, and, by reasonable effort, could not know that such third-party is prohibited from transmitting the document or information to the receiving Party by a contractual, legal or fiduciary obligation; or (v) such disclosure is made to PJM or PaPUC and is necessary in order for the Transactions contemplated by this Agreement to be consummated or to otherwise comply with the provisions of this Agreement.

(b) Notwithstanding any other provision of this Section 16.14, a Party may disclose to its employees, representatives and agents all documents and information furnished by the other Party in connection with this Agreement, provided that such employees, representatives and agents have been advised of the confidentiality provisions of this Section 16.14, and further provided that in no event shall a document or information be disclosed in violation of the standard of conduct requirements established by the FERC.

(c) A Party receiving notice or otherwise concluding that any confidential document or information furnished by the other Party in connection with this Agreement is being sought under any provision of law, to the extent it is permitted to do so under any applicable law or is being disclosed to PJM or PaPUC in order for the Transactions contemplated by this Agreement to be consummated or to otherwise comply with the provisions of this Agreement, shall: (i) promptly notify the other Party; and (ii) use reasonable efforts in cooperation with the other Party to seek confidential treatment of such confidential information.

(d) The Parties agree that monetary damages may be inadequate to compensate a Party for the other Party's breach of its obligations under this Section 16.14. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the receiving Party breaches or threatens to breach its obligations under this Section 16.14, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law.

16.15 Federal Acquisition Regulation

If any of the following clauses prescribed by the Federal Acquisition Regulation ("FAR"), 48 Code of Federal Regulations Chapter 1, should be deemed to apply to this Agreement, the DS Supplier shall comply with the requirements of such clause(s), and shall

include the terms or substance of such clause(s) in its subcontracts, as and to the extent required by the FAR:

1) Clean Air and Water: § 52.223-2;

2) Contract Work Hours and Safety Standards Act-Overtime Compensation: § 52.222-4;

3) Equal Opportunity: § 52.222-26;

4) Affirmative Action for and Employment Reports on Special Disabled and Vietnam Era Veterans: § 52.222-35 and § 52.222-37;

5) Affirmative Action for Handicapped Workers: § 52.222-36;

6) Utilization of Small Business Concerns and Small Disadvantaged Business Concerns and Small Business and Small Disadvantaged Business Subcontracting Plan: § 52.219-8 and § 52.219-9.

In case of a conflict between the provisions of the FAR and the balance of this Agreement, the requirements of the FAR shall prevail.

16.16 Binding Terms

This Agreement and the rates, terms and conditions herein shall remain in effect for the entire term hereof and each Party agrees not to seek any change to such rates, terms and conditions pursuant to the FPA, if the FPA is deemed to have jurisdiction over this Agreement, including on the grounds that they are not just and reasonable.

16.17 Amendment

This Agreement, including the appendices hereto, cannot be amended without the

written agreement of all Parties prior to such amendment becoming effective. Except as provided in Appendix C, the rates, terms and conditions contained in this Agreement are not subject to change under Sections 205 or 206 of the Federal Power Act absent the mutual written agreement of the Parties. To the extent permitted by law and absent agreement to the contrary, each Party, for itself and its successors and assigns, hereby expressly and irrevocably waives its rights to argue before any governmental authority that any review, modification, or rescission of this Agreement should be considered under any standard of review other than the "public interest" standard set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956)* and *Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956),* affirmed by *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County, Washington, et al., 554 U.S. 527 (2008)* (the "Mobile-Sierra Doctrine").

16.18 Counterparts and Electronic Signatures

This Agreement including all Transaction Confirmations hereunder may be executed in counterparts, each of which will be considered an original, but all of which shall constitute one instrument. Further, the Parties agree that the electronic signature of a Party to this Agreement and the forms appended herein shall be as valid as an original signature of such Party and shall be effective to bind such Party. The Parties agree that any electronically signed document shall be deemed (i) to be "written" or "in writing," (ii) to have been signed and (iii) to constitute a record established and maintained in the ordinary course of business and an original written record when printed from electronic files. Such paper copies or "printouts," if introduced as evidence in any judicial, arbitral, mediation or

administrative proceeding, will be admissible as between the Parties to the same extent and under the same conditions as other original business records created and maintained in documentary form. Neither Party shall contest the admissibility of true and accurate copies of electronically signed documents on the basis of the best evidence rule or as not satisfying the business records exception to the hearsay rule. For purposes hereof, "electronic signature" means either a manually signed original signature or an electronic symbol or process attached to or logically associated with a record and executed or adopted by a Party with the intent to sign the record that is then transmitted by electronic means; transmitted by "electronic means" means email transmission or other similar electronic or digital means of communication providing evidence of transmission, including transmission via the internet as a "pdf" (portable document format) or equivalent format. The use of electronic signature shall be approved by PPL Electric prior to use by the DS Supplier.

16.19 Successors

This Agreement and all of the provisions hereof are binding upon, and inure to the benefit of, the Parties and their respective successors and permitted assigns.

16.20 U.S. Stay Protocol

The Parties may, by mutual agreement, execute Appendix E attached hereto for purposes of incorporating the International Swaps and Derivatives Association 2018 U.S. Resolution Stay Protocol into this Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the date first set forth above.

[DS SUPPLIER]

BY: _____

NAME: _____

TITLE: _____

PPL ELECTRIC UTILITIES CORPORATION

BY: _____

NAME: _____

TITLE: _____

APPENDIX A
Maximum Unsecured Credit

S&P	Moody's	Fitch	Percentage of TNW	Credit Limit Cap ($)
A- and above	A3 and above	A- and above	5%	60M
BBB+	Baa1	BBB+	5%	40M
BBB	Baa2	BBB	5%	30M
BBB-	Baa3	BBB-	5%	15M
BB+	Ba1	BB+	5%	5M
BB	Ba2	BB	5%	3M
BB-	Ba3	BB-	5%	1M
Below BB-	Below Ba3	Below BB-	0	0

Credit Rating Determination Methodology

The DS Supplier or its Guarantor must have a minimum senior unsecured long-term debt rating (not supported by third-party credit enhancements, or, if unavailable, corporate issuer rating) equal to the Minimum Rating[1]. If the DS Supplier or its Guarantor is rated by more than one rating agency, and the ratings are split, the lowest of the available ratings will be used. The Maximum Credit Limit shall be calculated as the lesser of the percentage of TNW or the Credit Limit Cap.

[1] ***Minimum Rating*** *– The lowest credit rating, as set forth in this Appendix A, that a DS Supplier or Guarantor must have to obtain unsecured credit.*

APPENDIX B

MtM Credit Exposure Amount Calculation Information

Table 1 provides information that will be determined on each DS Solicitation Date for each month of the Delivery Period for each applicable Transaction. The initial mark for each Billing Month is the On-Peak Energy Forward Price and the Off-Peak Energy Forward Price on the date that the DS Solicitation closes and will not change over the life of the applicable Transaction.

After the close of the DS Solicitation On-Peak Energy Forward Prices and Off-Peak Energy Forward Prices will change.

MtM Calculation Example

Parameters

On the closing day of a DS Solicitation, the following parameters are set for each applicable Transaction:

(a) The estimated monthly onpeak load per tranche.
(b) The estimated monthly off-peak load per tranche.
(c) The monthly On-Peak Energy Forward Prices (to be used as the inception on-peak price "initial mark" for each month of the Delivery Period).
(d) The monthly Off-Peak Energy Forward Prices (to be used as the inception off-peak price "initial mark" for each month of the Delivery Period)

All On-Peak Energy Forward Prices and Off-Peak Energy Forward Prices are based on a Market Price Hub that the Company will specify as follows: PJM Western Hub.

Table 1 - Data set on the Closing Day of the DS Solicitation (MWh/Tranche)

	On-Peak Volume[2]	**Off-Peak Volume[3]**	**Initial Mark On-Peak Price[4]**	**Initial Mark Off-Peak Price[5]**
Month 1				
Month 2				
Month 3				
Month 4				
Month 5				
Month 6				
Month 7				
Month 7				
Month 8				
Month 9				
Month 10				
Month 11				
Month 12				

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EXAMPLE

Table 2 – Post DS Solicitation Close MTM Credit Exposure Calculation (MWh/Tranche)

	On-Peak Load per Tranche (MWh)	Off-Peak Load per Tranche (MWh)	Initial Mark On-Peak Price	Initial Mark Off-Peak Price	On-Peak Energy Forward Price[6]	Off-Peak Energy Forward Price[7]	MtM[8]
Month 1							
Month 2							
Month 3							
Month 4							
Month 5							
Month 6							
Month 7							
Month 8							
Month 9							
Month 10							
Month 11							
Month 12							
						Total	

Intentionally Left Blank (for expression purposes only)

[2] On-peak and off-peak volumes will be adjusted monthly.
[3] On-peak and off-peak volumes will be adjusted monthly.
[4] Initial Mark On-peak price set at day DS Solicitation closes. Remains constant through term of applicable Transaction.
[5] Initial Mark Off-peak price set at day DS Solicitation closes. Remains constant through term of applicable Transaction.
[6] On-peak Energy Forward Price as commercially available.
[7] Off-peak Energy Forward as commercially available.
[8] MTM = (On-Peak Load * (On-Peak Energy Forward Price - Initial Mark On-Peak Price) + (Off-Peak Load *(Off-Peak Energy Forward Price- Initial Mark Off-Peak Price)

APPENDIX C

DS Supply Specifications

1) With respect to a Transaction, DS Supplier shall provide Full Requirements Service on a firm and continuous basis. The terms of the Transaction shall be set forth in a Transaction Confirmation to this Agreement, in a form as set forth in Exhibit 1. Full Requirements Service shall mean, all of the following necessary services or products that are required to supply the DS Supplier Responsibility Share for the DS Customers associated with the Transaction Confirmation, including: Energy, Capacity, transmission (other than Non-market-based Transmission Services), Ancillary Services, Alternative Energy Credits for compliance with the AEPS Act less Allocated AECs, transmission and distribution system losses, congestion management costs, and such other products and services that are required except for distribution service.

2) With respect to a Transaction, the Company shall be responsible, at its sole cost and expense, for the costs of Non-market-based Transmission Services. Additionally, the Company will be responsible for any distribution service necessary to serve the DS Supplier Responsibility Share.

3) Except as provided in Paragraph 1 above, DS Supplier bears the risk of any other changes in PJM products and pricing during the term of all Transactions under this Agreement. However, if there are any other new FERC-approved PJM transmission charges other than those referred to in Paragraph 1 above or other new

PJM charges and costs, charged to network transmission customers, that DS Supplier believes the Company should recover through retail rates because they are directly related to the Company's obligations, then Company may file with the PaPUC a request for approval to recover such new costs. DS Supplier is required to intervene in any such proceeding before the PaPUC. Such new costs can only be charged to the Company to the extent that the PaPUC approves the Company's recovery of those costs. DS Supplier agrees to be bound by the decision of the PaPUC (subject to the normal rules for appeal of the decision of the PaPUC) and waives all claims concerning this issue before the FERC. Notwithstanding the foregoing, nothing in the Agreement shall preclude DS Supplier or Company from taking any position before the FERC regarding the creation and allocation of any such PJM charges.

Customer Group and Service Type:

Customer Group	Rate Schedule	Description
Residential	RS	RS – Residential Service
	RTS	RTS(R) – Residential Service – Thermal Storage
Small Commercial & Industrial	GS-1	GS-1 – Small General Service
	GS-3	GS-3 – Large General Service – Customers with less than 100 kW peak demand
	LP-4	LP-4 – Large General Service (12 KV or Higher) – Customers with less than 100 KW peak demand
	GH-2	GH-2(R) – Separate Meter General Space Heating Service
	BL	BL – Borderline Service – Electric Utilities
	SA	SA – Private Area Lighting
	SM	SM(R) – Mercury Vapor Street Lighting
	SHS	SHS – High Pressure Sodium Street Lighting
	SE	SE – Energy Only Street Lighting Service
	TS	TS(R) – Municipal Traffic Signal Lighting Service
	SI-1	SI-1(R) – Municipal Street Lighting
	Standby	Rule 6A – Standby Service for Qualifying Facilities applicable to customers in the above listed rate schedules.
Large Commercial & Industrial	GS-3	GS-3 – Large General Service – Customers with 100 KW or higher peak demand
	LP-4	LP-4 – Large General Service (12 KV or Higher) – Customers with 100 KW or higher peak demand
	LP-5	LP-5 – Large General Service (69 KV or Higher)
	LPEP	Power Service to Electric Propulsion
	Standby	Rule 6A – Standby Service for Qualifying Facilities applicable to customers in the above listed rate schedules.

Notes:
1. Rate schedules also may be subject to riders. Any such riders are set forth in PPL Electric Utilities Corporation General Tariff, Rules and Rate Schedules for Electric Service.
2. LPEP will be included in the Large C&I Customer Group only if Amtrak requests 60 Hz electricity supply.
3. Rate Schedule LP-4 customers with less than 100 KW peak demand will be included in the Small C&I Customer Group and Rate Schedule GS-3 customers with 100 KW or greater peak demand will be included in the Large C&I Customer Group. The initial determination of peak demand will be based on the customer's ICAP peak load contribution assigned for the June 1, 2025 date by PJM Interconnection, LLC ("PJM") and will take effect starting June 1, 2025. All following determinations of peak demand and classification of customers will be reassessed annually on June 1 each year thereafter, throughout the period of June 1, 2026 through May 31, 2029.

4. Time-of-Use load will be included in the calculation of Default Service Load.

APPENDIX D

DS Supplier's Obligations for AEPS Compliance

To satisfy AEPS with respect to the DS Supplier's DS Supplier Responsibility Share, DS Supplier has the following obligations:

(1) DS Supplier shall enable the Company to comply with the Alternative Energy Portfolio Standards, including regulations adopted thereunder, (together the AEPS Obligation) and shall provide its proportional share of AECs to fulfill the Company's AEPS Obligation as set forth in the AEPS Act and PaPUC rules and Orders that may be promulgated to implement the AEPS Act.

(2) Provide the required percentage of each type of AEC as set forth in Exhibit 2 less Allocated AECs;

(3) Paying any AEPS penalties, costs, charges, etc. assessed against the DS Supplier and/or the Company associated with the DS Supplier's non-performance with AEPS requirements;

(4) DS Supplier shall establish the proper accounts within the GATS. DS Supplier shall be a subscriber to GATS and is responsible for paying its annual subscription fee. DS Supplier shall transfer AECs into the Buyer's account(s) in the amount necessary to fulfill DS Supplier's AEPS Obligation under this Agreement. DS Supplier shall be responsible for paying the volumetric fees associated with LSE GATS fee requirements in proportion to DS Supplier's DS Supplier Responsibility Share.

(5) Within 40 calendar days following the conclusion of each quarter throughout the PJM planning year (August 31, November 30, February 28/29, and May 31) during the Delivery Period of a given Transaction, the DS Supplier shall transfer AECs into the Company's GATS account(s) in an amount commensurate with the AECs applicable to the Full Requirements Service provided by the DS Supplier during the applicable quarter.

(6) At the conclusion of each annual June to May Period ("Reporting Period"), DS Supplier shall complete its transfer of any AECs not transferred in accordance with this Appendix D and Exhibit 2, into the Company's GATS account(s) in the amount necessary to fulfill the DS Supplier's AEPS Obligation under this Agreement. Transfers must be made no later than 70 calendar days following the completion of a Reporting Period.

(7) DS Supplier may not transfer AECs in advance of future Reporting Periods.

(8) Submitting to the Company proof of AEPS compliance under this Agreement in such form and manner as may be required by the Company.

(9) Provide to the Company all information the Company may require to comply with the AEPS Act and its implementing regulations and other Requirements of Law, including, but not limited to, the price paid per AEC required by 73 P.S. §§1648.3(e)(8).

(10) In addition the Remedies stated in Article 13 (Limitations of Remedies Liabilities and Damages) and Article 14 (Indemnification) of this Agreement, Company shall have the right, in its reasonable discretion, to withhold any and all

payments pursuant to Article 9 (Billing and Payment) of this Agreement in the event that the DS Supplier does not satisfy its obligations under this Appendix, and to pursue any other remedies at law or in equity which may be available including, but not limited to those enumerated in Article 14 (Indemnification). Moreover, the DS Supplier will be liable for any additional AECs and/or costs directly or indirectly related to the procurement of AECs by the Company or related to any penalties and costs associated with non-compliance of the AEPS Act in the event that the DS Supplier defaults on its obligations under this Appendix.

(11) Any Allocated AECs as set forth in Exhibit 2 are intended to be a reduction in the DS Supplier's AEC delivery requirements, and shall remain the property of Company and shall not be transferred to DS Supplier.

APPENDIX E

ADHERENCE TO THE U.S STAY PROTOCOL

The Parties may, by mutual agreement, execute this Appendix E for purposes of incorporating the International Swaps and Derivatives Association ("ISDA") 2018 U.S. Resolution Stay Protocol ("ISDA U.S. Stay Protocol") into this Default Service Supplier Master Agreement.

This Appendix E is part of the Default Service Supplier Master Agreement dated _____, 20__(as amended, modified or extended from time to time) between PPL Electric Utilities Corporation (the "Buyer") and _____ (the "DS Supplier").

DS Supplier hereby confirms that it is an adherent to the ISDA U.S. Stay Protocol. Buyer confirms that it is or that it will become an adherent to the ISDA U.S. Stay Protocol. If Buyer is not an adherent to the ISDA U.S. Stay Protocol when this Appendix E is executed, Buyer will submit an Adherence Letter for acceptance by the ISDA no later than ten (10) Business Days after execution of this Appendix E.

The terms of the ISDA U.S. Stay Protocol are incorporated into and form a part of the Default Service Supplier Master Agreement, and the Default Service Supplier Master Agreement shall be deemed a Protocol Covered Agreement for purposes thereof. For purposes of incorporating the ISDA U.S. Stay Protocol, DS Supplier shall be deemed to be a Regulated Entity and Buyer shall be deemed to be an Adhering Party. In the event of any inconsistences between the Agreement and the ISDA U.S. Stay Protocol, the ISDA U.S. Stay Protocol will prevail.

The terms "Regulated Entity", "Adhering Party", "Adherence Letter" and "Protocol Covered Agreement" shall have the meanings given to them in the ISDA U.S. Stay Protocol. All other terms not defined herein shall have the meanings given to them in the Default Service Supplier Master Agreement between the Parties.

PPL ELECTRIC UTILITIES CORPORATION

BY: _____

NAME: _____

TITLE: _____

[DS SUPPLIER]

BY: _____

NAME: _____

TITLE: _____

EXHIBIT 1 – TRANSACTION CONFIRMATION EXAMPLE

This Transaction Confirmation letter is being provided pursuant to and in accordance with the Default Service Supplier Master Agreement ("Agreement") dated [INSERT SMA Effective DATE] between PPL Electric Utilities Corporation ("Company") and [INSERT DS SUPPLIER NAME] ("DS Supplier"). Terms used but not defined herein shall have the meanings ascribed to them in the Agreement. This Transaction Confirmation shall confirm the following terms of the Transaction agreed to on [INSERT DS Solicitation PaPUC approval date] ("Transaction Date").

Transaction Type: [Fixed Price Transaction / Spot Market Transaction]

Product: Full Requirements Service

Customer Group: Residential

Service Type: Rate Schedules RS and RTS.

Delivery Point: PPL_RESID_AGG

Delivery Period: [MONTH] [DAY], [YEAR] through [MONTH] [DAY], [YEAR]

Capacity Supplement Applies? Yes/No

The DS Supplier's DS Supplier Responsibility Share is [INSERT]. DS Supplier will supply [INSERT] Tranche(s) at a DS Fixed Price of $ [INSERT] per MWh for the duration of the Delivery Period.

Service Type	Total Tranches	% Size of a Tranche	PLC (MW)	MW-Measure
Rate Schedules RS and RTS	[INSERT]	[INSERT]	[INSERT]	[INSERT]

Capacity Supplement:

The Delivery Year for purposes of this Capacity Supplement is June 1, 20__ to May 31, 20__. The Delivery Period overlaps with part or all of the Delivery Year. This Capacity Supplement applies if the results for the Base Residual Auction ("BRA") under PJM's Reliability Pricing Model ("RPM"), or any successor, for the Delivery Year were not announced by PJM at least five (5) business days prior to the Bid Date. The Bid Date was

Month XX, 20XX. If the Capacity Supplement applies, it will become effective on the Transaction Date and will expire at the end of the Delivery Period.

Except as specifically modified in and by this Capacity Supplement, all terms and conditions of the Agreement, including all Appendices, Exhibits, and payment provisions under Article 9, shall remain in full force and effect and shall apply to the Transaction. For purposes of this Capacity Supplement: (i) the "Capacity Price" is the price paid by DS Suppliers for Capacity for the Delivery Point, in $ per MW-day, for the Delivery Year as set forth in the PJM Agreements, or any successor; and (ii) the "Capacity Proxy Price" is $_____/MW-day. The Capacity Proxy Price is the average of the most recent results under PJM's RPM for the two most recent delivery years for which PJM has held a capacity auction. For the avoidance of doubt, the results of the most recent Incremental Auction held under PJM's RPM would be used if an Incremental Auction has been held for a delivery year.

The Parties agree as follows:

Section 9.1 (a)(i) of the Agreement is replaced for purposes of payment for the Transaction referenced herein with:

With respect to each Fixed Price Transaction, for each Billing Month, the Company will prepare a Statement of amounts due to the DS Supplier. This Statement will show the aggregate amounts due based on the DS Fixed Price indicated in such Transaction Confirmation multiplied by the PMEA of the Billing Month. For each month of the Delivery Year that is also a Billing Month of the Delivery Period, this Statement will include an additional line item that will show the sum, over all days of the Billing Month, of the difference between the Capacity Price actually charged for load served for the Delivery Point and the Capacity Proxy Price, multiplied by the amount of Capacity for the day reported as the DS Supplier's Capacity obligation by Buyer to PJM for the Transaction.

Section 9.1 (a)(ii) of the Agreement is replaced for purposes of payment for the Transaction referenced herein:

With respect to each Fixed Price Transaction, to the extent that the FMEA differs from the PMEA, the Company shall pay or charge the DS Supplier for the PMEA/FMEA Adjustment Amount within the PJM deadline for conducting the final settlement. To the extent that the daily Capacity obligations used in the calculation detailed in Section 9.1(a)(i) are adjusted, the Company will pay or charge the DS Supplier any net difference between the payment made and the payment calculated using the adjusted values. For avoidance of doubt, the MW of Capacity reported as DS Supplier's Capacity obligation shall be adjusted for any subsequent meter corrections reported to PJM, or as a result of any subsequent retail load settlement process. Any reduction in load as a result of Buyer's

or PJM's operation of its load response programs shall be reflected as a reduction in the MW of Capacity.

Please confirm that the terms stated herein accurately reflect the agreement reached on the date above between the DS Supplier and the Company by returning an executed copy of this Transaction Confirmation by pdf to the Company at zDSPEnergyProcurement@pplweb.com. The signatories to this Transaction must have the authority to enter into this Transaction.

PPL ELECTRIC UTILITIES CORPORATION

BY: _____

NAME: _____

TITLE: _____

[DS SUPPLIER]

BY: _____

NAME: _____

TITLE: _____

EXHIBIT 2 - ALTERNATIVE ENERGY PORTFOLIO STANDARDS OBLIGATION

This Exhibit 2 shall confirm the Alternative Energy Portfolio Standards obligation of the Transaction agreed to on _____ ("Transaction Date").

Residential Load Obligation:

Reporting Period	Tier I	PV(included in Tier I Obligation)	Tier II
6/1/25 to 5/31/26			
6/1/26 to 5/31/27			
6/1/27 to 5/31/28		Intentionally Left Blank (for expression purposes only)	
6/1/28 to 5/31/29			
6/1/29 to 5/31/30			
6/1/30 to 5/31/31			

Small Commercial & Industrial Load Obligation:

Reporting Period	Tier I	PV(included in Tier I Obligation)	Tier II
6/1/25 to 5/31/26			
6/1/26 to 5/31/27			
6/1/27 to 5/31/28		Intentionally Left Blank (for expression purposes only)	
6/1/28 to 5/31/29			
6/1/29 to 5/31/30			

6/1/30 to 5/31/31

Large Commercial & Industrial Load Obligation:

Reporting Period	Tier I	PV(included in Tier I Obligation)	Tier II
6/1/25 to 5/31/26			
6/1/26 to 5/31/27			
6/1/27 to 5/31/28		Intentionally Left Blank (for expression purposes only)	
6/1/28 to 5/31/29			
6/1/29 to 5/31/30			
6/1/30 to 5/31/31			

The percentages set forth above may be revised for future DS Solicitations to reflect changes in law or other applicable regulatory requirements. DS Supplier shall provide the percentages set forth above in order to comply with its obligations under Full Requirements Service and the Company shall adjust the quantities/products being procured in future DS Solicitations to make up any shortfall or utilize any excess AECs resulting from such change. Any such adjustments will be made known to bidders prior to the conclusion of the applicable DS Solicitation.

Allocated AECs:

AEPS Reporting Period	Tier I (non-solar PV)		Tier I (solar PV)		Tier II AECs	
	Allocated AECs Per Tranche	Total Allocated AECs	Allocated AECs Per Tranche	Total Allocated AECs	Allocated AECs Per Tranche	Total Allocated AECs
June 1, 2025-May 31, 2026						
June 1, 2026-May 31, 2027						
June 1, 2027-May 31, 2028						
June 1, 2028-May 31, 2029						
June 1, 2029-May 31, 2030						
June 1, 2030-May 31, 2031						

EXHIBIT 3 – FORM OF NOTICE

Any notices required under this Agreement shall be made as follows:

BUYER: PPL Electric Utilities Corporation	DS Supplier: [INSERT]
All Notices:	**All Notices:**
Street:	Street:
City/State/Zip:	City/State/Zip:
Attn:	Attn:
Duns: **00-790-9427**	Duns:
Federal Tax ID Number: **23-0959590**	Federal Tax ID Number:
Email:	Email:
Invoices:	**Invoices:**
Attn:	Attn:
Phone:	Phone:
Email:	Email:
Scheduling:	**Scheduling:**
Attn:	Attn:
Phone:	Phone:
Email:	Email:
Payments:	**Payments:**
Attn:	Attn:
Phone:	Phone:
Email:	Email:

Wire Transfer BNK: **Wells Fargo** ABA: _____ ACCT: _____	**Wire Transfer** BNK: ABA: ACCT:
Credit and Collections: Attn: **John Early** Phone: **502-627-4253** Email: **pplmargincall2@pplweb.com**	**Credit and Collections:** Attn: Phone: Email:
With Additional Notices of an Event of Default to: Attn: Phone: Email:	**With Additional Notices of an Event of Default to:** Attn: Phone: Email:

For any notices under Section 6.6 shall be made as follows:

BUYER: PPL Electric Utilities Corporation	DS Supplier: [INSERT]
Attn: **John Early** Street: **220 West Main Street** City/State/Zip: **Louisville, KY 40202**	Attn: Street: City/State/Zip:
Copy to: Street: **827 Hausman Rd., 1st Floor** City/State/Zip: **Allentown, PA 18104**	Copy to: Street: City/State/Zip:

EXHIBIT 4 – PJM DECLARATION OF AUTHORITY

This Declaration of Authority ("Declaration") is made this ____ day of _____, 201_ by the following:

PARTY A: PPL Electric Utilities Corporation ("Party A").

PARTY B: _____ ("Party B").

RECITALS

WHEREAS, PJM is a Regional Transmission Organization ("RTO") subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC");

WHEREAS, PJM Settlement, Inc ("PJM Settlement") is a Pennsylvania Non-Profit Corporation, incorporated for the purpose of providing billing and settlement functions and credit and risk management functions for PJM. References to "PJM" in this Declaration are intended to apply to PJM and/or PJM Settlement, as appropriate, with regard to their respective functions.

WHEREAS, PJM and PJM Settlement administer centralized markets that clear various electric energy and energy-related products among multiple buyers and sellers;

WHEREAS, PJM additionally exercises operational control over its members' transmission facilities whereby PJM provides open-access transmission service and control area functions, including economic dispatch and emergency response to ensure reliability;

WHEREAS, Party A is a PJM Member and seeks to obtain, or is obtaining, services provided or administered by PJM, seeks to participate, or is participating in, markets administered by PJM, or seeks to engage in, or is engaging in, operations that use or affect the integrated transmission system operated by PJM;

WHEREAS, such activities or contemplated activities by Party A and Party B are governed by rights and obligations established by or under the PJM Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), the Reliability Assurance Agreement Among Load-serving Entities in the MAAC Control Zone ("RAA"), and other agreements, manuals, and practices of PJM (the Tariff, the Operating Agreement, the RAA, and such other agreements manuals, and practices of PJM, the "PJM Agreements"); and

WHEREAS, Party A and Party B desire to declare to PJM their respective authorities concerning such rights and obligations, intend that PJM rely upon such declaration, and acknowledge that PJM may rely upon such declaration to its detriment.

DECLARATION

NOW, THEREFORE, acknowledging that PJM will rely on the truth, accuracy and completeness of the declarations made below, Party A and Party B, as identified below, make the following declarations:

1. Exclusivity of Party B's Authority.

Pursuant to a binding, legally enforceable agreement, Party A has authorized Party B to act for Party A with respect to certain rights and responsibilities as specified in Section 2 of this Declaration ("the Authorized Rights and Responsibilities"). With respect to the Authorized Rights and Responsibilities, Party B is authorized to communicate and transact with PJM as Party A's sole and exclusive Party B, and PJM is authorized to communicate and transact directly and exclusively with Party B as Party A's Party B. With respect to Authorized Rights and Responsibilities, Party A will abide by any direction issued by PJM to Party B.

2. Specification of Authorized Rights and Responsibilities.

In the following parts (a) through (h), Party A and Party B specify the rights and responsibilities with respect to which Party B is authorized to act for Party A. Specification shall be effective only if both Party A and Party B have placed the initials of their authorized representatives in the space provided for each applicable right or responsibility from among the options provided below:

(a) Load Server Responsibilities.

_____ _____ Party B is authorized to satisfy Party A's obligations as a Load-Serving Entity under the RAA, including, without limitation, its obligations to provide Unforced Capacity, submit capacity plans, provide or arrange for Capacity Resources, satisfy Accounted-for Obligations and Peak Season Maintenance Obligations, comply with any capacity audits, make payment of all deficiency, data submission, and emergency procedure charges incurred, coordinate planning and operation of Capacity Resources with other parties; and develop and submit planned outage schedules.

_____ _____ Party B is authorized to satisfy Party A's obligations under the Tariff, RAA and to provide or arrange for transmission service to its loads; provide or

arrange for sufficient reactive capability, voltage control facilities, and black start capability for service to its loads; submit firm transmission service schedules, and designate Network Resources and other points of receipt and delivery for transmission service. Party B is authorized to request changes to the transmission service required for service to Party A's loads, and to enter into, on Party A's behalf, any feasibility, system impact, facilities study, or other agreements required to process such request for a change in service.

_____ _____ Party B is authorized to satisfy Party A's rights and obligations under the Tariff and Operating Agreement to submit bids on, obtain, administer, and receive payments or credits for Financial Transmission Rights and Auction Revenue Rights with respect to service to Party A's loads.

_____ _____ Party B is authorized to provide data required by PJM with respect to service to Party A's loads, including, but not limited to, data required for coordination of operations, accounting for all interchange transactions, preparation of required reports and maintenance schedules, and analysis of system disturbances.

_____ _____ Party B is authorized to provide the facilities and personnel required to coordinate operations with PJM and other PJM Members.

(b) Electric Distributor Responsibilities.

_____ _____ Party B is authorized to satisfy Party A's rights and obligations as an Electric Distributor under the Operating Agreement, including, but not limited to, assuring the continued compatibility of its local energy management, monitoring, and telecommunications systems with PJM's technical requirements; providing or arranging for the services of a 24-hour local control center to coordinate with PJM; providing to PJM all system, accounting, customer tracking, load forecasting, and other data necessary or appropriate to implement or administer the Operating Agreement, RAA; shedding connected load, initiating active load management programs, and taking such other coordination actions as may be necessary in accordance with PJM's directions in Emergencies; maintaining or arranging for a portion of its connected load to be subject to control by automatic underfrequency, under-voltage, or other load-shedding devices; and complying with the underfrequency relay obligations and charges specified in the Operating Agreement.

(c) Generator Responsibilities.

_____ _____ Party B is authorized to operate the Party A's generation resources in all events, including, but not limited to, in the event of Emergencies, and shall operate such resources in a manner that is consistent with the standards, requirements or directions of PJM and that will permit PJM to perform its obligations under the Operating Agreement, Tariff, RAA, and other applicable agreements, manuals, and practices.

_____ _____ Party B is authorized to ensure that the required portion of Party A's Capacity Resources have the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

- Or –

_____ _____ Party B is authorized to direct the operation of Party A's generation resources by relaying PJM's instructions to the resource in all events, including, but not limited to, in the event of Emergencies, and shall direct such resources in a manner that is consistent with the standards, requirements or directions of PJM and that will permit PJM to perform its obligations under the Operating Agreement, Tariff, RAA, and other applicable agreements, manuals, and practices.

_____ _____ Party B is authorized to communicate with PJM in all matters concerning the provision of capacity, energy, or ancillary services from Party A's generation resources, including, without limitation, information required in connection with Capacity Resources, dispatch of any unit, provision of reactive power, regulation, synchronous condensing, spinning or other reserves, establishment or maintenance of a unit as a Black-Start Unit, satisfaction of must-run obligations, and costs or revenue requirements for any product or service offered by any such unit.

_____ _____ Party B is authorized to provide information on outages of Party A's generation facilities, whether planned, forced, or for maintenance, and to coordinate such outages with PJM

_____ _____ Party B is authorized to act on behalf of Party A with respect to Party A's rights and obligations under any Feasibility Study, System Impact Study, or Facilities Study Agreements.

_____ _____ Party B is authorized to act on behalf of Party A with respect to Party A's rights and obligations under any Construction Service Agreements.

_____ _____ Party B is authorized to act on behalf of Party A with respect to Party A's rights and obligations under any Interconnection Service Agreements.

____ _____Party B is authorized to receive from PJM historic and real time data collected by PJM from, or provided to PJM by, Party A with respect to Party A's generation resources.

_____ _____Party B is authorized to act on behalf of Party A for the following specific unit(s) in Party A primary and subaccounts:

Resource Name: Resource ID:

(d) Market Buyer/Market Seller Responsibilities.

_____ _____ Party B is authorized to satisfy Party A's rights and obligations as a Market Buyer or Market Seller under the Operating Agreement, including, but not limited to, arranging for a Market Operations Center capable of real-time communication with PJM during normal and Emergency conditions; reporting to PJM sources of energy available for operation; providing to PJM scheduling and other information, including, but not limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, and other load reduction measures; obtaining Spot Market Backup for bilateral transactions; submitting to PJM binding offers to purchase or sell energy and ancillary services in compliance with all applicable Offer Data specifications; responding to PJM's directives to start, shut down or change output levels of generation units, or change scheduled voltages or reactive output levels; responding to PJM's directives to schedule delivery or change delivery schedules for external resources; and following PJM's directions to take actions to prevent, manage, alleviate or end an Emergency.

(e) Billing and Payment Responsibilities.

_____ _____ In connection with all rights and responsibilities specified by Party A and Party B in any of subparts (a) through (d) of this Section, Party B shall be billed for, and shall make payment to PJM for, all charges, penalties, costs and fees. (If this option is not specified, PJM will issue billings to, and collect amounts due from, Party A.)

_____ _____ In connection with all rights and responsibilities specified by Party A and Party B above, Party B is entitled to receive from PJM in Party B's account all credits, revenues, distributions, and disbursements. (If this option is not specified, PJM will pay such amounts to Party A.)

(f) General Membership Responsibilities.

_____ _____ Party B is authorized to participate and vote in all PJM committees, working groups, and other stakeholder bodies on Party A's behalf.

_____ _____ Party B is authorized to participate on Party A's behalf in the regional transmission expansion planning process.

_____ _____ Party B is authorized to provide information or otherwise cooperate on Party A's behalf in connection with any investigation or request for information by PJM or the PJM Market Monitoring Unit in accordance with the Operating Agreement and Attachment M to the Tariff. (If this option is specified, PJM and the PJM Market Monitoring Unit shall have the right to request and obtain such information from Party B and/or Party A.)

_____ _____ Party B shall be billed for, and shall make payment of, Party A's costs of membership in PJM, including payment of the Membership fee, and payment of any other general assessments on the PJM members, including, but not limited to, amounts assessed as a consequence of defaults by other Members.

(g) Additional Responsibilities.

_____ _____ Party B has been Authorized other rights and responsibilities of Party A as specified on Attachment "A" to this Declaration.

(h) Limitation on Responsibilities.

_____ _____ The rights and responsibilities specified in parts (a) through (f) above apply to a limited portion of Party A's facilities or loads located in the PJM Region, as specified on Attachment "B" to this Declaration, and to no other facilities or loads of Party A.

3. Continuing Responsibilities and Liabilities of Party A.

3.1 The Authorized Rights and Responsibilities are the only rights and responsibilities under the PJM Agreements for which Party B is authorized to

act for Party A, and Party A retains all rights and responsibilities under the PJM Agreements not specified by Party A and Party B in Section 2.

3.2 With respect to the Authorized Rights and Responsibilities, and notwithstanding any other provision of this Agreement, Party A shall remain liable to PJM for all amounts due or to become due to PJM under the PJM Agreements, and Party B's authorization to make payment of any such amounts hereunder (if specified in Section 2) shall not release Party A from liability for any financial obligations to PJM not satisfied by Party B.

4. Reliance and Indemnity, Duty to Inform, Liability Waiver, and Rules of Construction.

4.1 Party A and Party B each recognizes, accepts and intends that PJM will rely, upon on the truth, accuracy and completeness of the declarations herein in matters including but not limited to creditworthiness and in assuring compliance with the PJM Agreements. Party A and Party B each recognizes and accepts that PJM or its members may suffer losses and damages if any declaration is or becomes untrue, inaccurate or incomplete, and each agrees to indemnify PJM for any such losses and damages.

4.2 Party A and Party B each has a continuing duty to notify PJM if and when any declaration herein ceases to be truthful, accurate or complete. Until such time as PJM receives written notification of any change to any declaration, in accordance with the terms contained herein, PJM shall be entitled to rely perpetually on this Declaration as governing its relationship with Party A and Party B as to the subject matter of this Declaration. Written notice of changes to the declarations contained herein must be provided by Party A (PJM Member) to PJM at least thirty days in advance of their effectiveness. If Party B is also a PJM Member, then both parties will be required to provide thirty days prior written notification in order for such changes to be effective. Such notification is required for changes to the declarations and responsibilities contained herein and/or termination of this Declaration. Upon such termination, all rights, responsibilities and accounts will revert back to the original status quo prevailing before the Declaration became effective. Should less than thirty days' notice be provided, PJM shall use its best efforts to accommodate and process the declarations herein, but all attempts should be made to provide such notice.

4.3 Nothing in this Declaration shall be construed to create or give rise to any liability on the part of PJM and Party A and Party B expressly waive any claims that may arise against PJM under this Declaration. This Declaration shall not be construed to modify any of the PJM Agreements and in the event of conflict

between this Declaration and a PJM Agreement, the applicable PJM Agreement shall control.

4.4 Capitalized terms used herein that are not defined herein have the meanings given in the PJM Agreements, as applicable.

4.5 The Recitals are hereby incorporated into the body of this Declaration.

IN WITNESS WHEREOF, Party A and Party B execute this Declaration to be effective as of the date written above or upon receipt of a fully executed original by PJM, whichever date is later.

PARTY A:	**PARTY B:**
Signature:_____	Signature:_____
Name: _____	Name: _____
Title:_____	Title:_____
Company Name: PPL Electric Utilities Corporation	Company Name:_____

EXHIBIT 5 - PERFORMANCE ASSURANCE EVERGREEN LETTER OF CREDIT

(ELECTRONIC "eUCP CREDIT")

{TO BE ISSUED ON THE LETTERHEAD OF THE ISSUING BANK}

IRREVOCABLE STANDBY LETTER OF CREDIT NO. _____

ISSUE DATE _____ **EXPIRY DATE**: _____

APPLICANT

[NAME]

[ADDRESS]

BENEFICIARY
PPL ELECTRIC UTILITIES CORPORATION
220 WEST MAIN ST.
LOUISVILLE, KY 40202
ATTN: MANAGER, CREDIT AND CONTRACT ADMINISTRATION

ELECTRONIC ISSUE ADDRESS: PPLMARGINCALL2@PPLWEB.COM

CURRENCY AMOUNT
USD *********$ _____

WE (THE "ISSUER") HEREBY ISSUE IN YOUR FAVOR OUR IRREVOCABLE STANDBY LETTER OF CREDIT NO: _____ (THE "LETTER OF CREDIT," WHICH SHALL BE AN "eUCP CREDIT") FOR THE ACCOUNT OF APPLICANT FOR AN AMOUNT OR AMOUNTS NOT TO EXCEED IN THE AGGREGATE US DOLLARS _____ AVAILABLE BY YOUR DRAFT(S) AT SIGHT AT OUR COUNTERS LOCATED AT_____ [INSERT ISSUER'S PLACE FOR PRESENTATION], EFFECTIVE _____ AND EXPIRING ON _____ AT 5:00 PM NEW YORK, NEW YORK TIME OR ANY AUTOMATICALLY EXTENDED EXPIRY DATE, AS PROVIDED HEREIN. THIS LETTER OF CREDIT IS AVAILABLE IN ONE OR MORE DRAFTS UP TO THE AGGREGATE AMOUNT SET FORTH HEREIN.

THIS LETTER OF CREDIT IS PRESENTABLE AND PAYABLE AT OUR

COUNTERS AS AN eUCP CREDIT, AND WE HEREBY ENGAGE WITH YOU THAT DRAFTS DRAWN UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE HONORED ON PRESENTATION, IF ACCOMPANIED BY THE REQUIRED DOCUMENTS PURSUANT TO THE TERMS OF THIS LETTER OF CREDIT.

THIS ORIGINAL LETTER OF CREDIT HAS BEEN ISSUED VIA ELECTRONIC MEANS ONLY TO PPLMARGINCALL2@PPLWEB.COM. WE CONFIRM THAT THE ELECTRONIC PDF FILE OF THIS LETTER OF CREDIT (TOGETHER WITH ELECTRONIC PDF FILES OF SUBSEQUENT AMENDMENTS, IF ANY) SERVES AS THE OPERATIVE INSTRUMENT, AND THAT THE BENEFICIARY MAY USE THE ELECTRONIC PDF FILE OF THE LETTER OF CREDIT (TOGETHER WITH ELECTRONIC PDF FILES OF SUBSEQUENT AMENDMENTS, IF ANY) AS IT WOULD A HARD COPY ORIGINAL.

DRAFTS, DOCUMENTS AND OTHER COMMUNICATIONS HEREUNDER MAY BE PRESENTED OR DELIVERED TO US BY EMAIL OR BY ANY OTHER ELECTRONIC MEANS. PRESENTATION OR DELIVERY BY EMAIL MUST BE MADE FROM YOUR EMAIL ADDRESS: PPLMARGINCALL2@PPLWEB.COM TO THE FOLLOWING ISSUER EMAIL ADDRESS: _____[INSERT ISSUER EMAIL ADDRESS], AND CONFIRMED BY TELEPHONE TO US AT ONE OF THE FOLLOWING NUMBER(S): _____ OR _____[INSERT TELEPHONE NUMBERS FOR CONFIRMATION]. IN THE EVENT OF A PRESENTATION BY EMAIL OR BY OTHER ELECTRONIC MEANS, NO REGULAR MAIL PRESENTATION OR DELIVERY IS NECESSARY, AND THE TRANSMISSION BY EMAIL OR BY OTHER ELECTRONIC MEANS WILL CONSTITUTE CONFORMING PRESENTATION OR DELIVERY.

THE BELOW MENTIONED DOCUMENT(S) MUST BE PRESENTED ON OR BEFORE THE EXPIRY DATE OR ANY AUTOMATICALLY EXTENDED EXPIRY DATE, AS PROVIDED HEREIN, OF THIS INSTRUMENT IN ACCORDANCE WITH THE TERMS AND CONDITIONS OF THIS LETTER OF CREDIT.

1. YOUR SIGNED STATEMENT, READING AS FOLLOWS (WITH BLANKS APPROPRIATELY COMPLETED AND BRACKETED INSTRUCTIONS DELETED):

> "THE AMOUNT FOR THIS DRAWING, USD [INSERT AMOUNT], BEING MADE UNDER THE [INSERT NAME OF BANK] IRREVOCABLE STANDBY LETTER OF CREDIT NO. [INSERT LETTER OF CREDIT REFERENCE NUMBER], REPRESENTS AN

AMOUNT DUE AND PAYABLE TO BENEFICIARY FROM APPLICANT OR AN AFFILIATE OF APPLICANT UNDER THE PPL ELECTRIC UTILITIES CORPORATION DEFAULT SERVICE SUPPLIER MASTER AGREEMENT DATED [INSERT DATE OF SUCH AGREEMENT] BETWEEN APPLICANT OR AN AFFILIATE OF APPLICANT AND BENEFICIARY, AND THIS STATEMENT SHALL BE THE NOTICE OF COMPLETENESS FOR THIS PRESENTATION UNDER THE ABOVE-REFERENCED LETTER OF CREDIT."; OR

"AN EVENT OF DEFAULT UNDER THE PPL ELECTRIC UTILITIES CORPORATION DEFAULT SERVICE SUPPLIER MASTER AGREEMENT DATED [INSERT DATE OF SUCH AGREEMENT] BETWEEN APPLICANT OR AN AFFILIATE OF APPLICANT AND BENEFICIARY HAS OCCURRED AND THAT BENEFICIARY DEMANDS PAYMENT IN THE AMOUNT OF [INSERT AMOUNT UP TO ENTIRE REMAINING UNDRAWN AMOUNT] PURSUANT TO SUCH AGREEMENT, AND THIS STATEMENT SHALL BE THE NOTICE OF COMPLETENESS FOR THIS PRESENTATION UNDER THE ABOVE-REFERENCED LETTER OF CREDIT."; OR

"THE EXPIRY DATE OF IRREVOCABLE STANDBY LETTER OF CREDIT NO. [INSERT LETTER OF CREDIT REFERENCE NUMBER] IS LESS THAN THIRTY (30) DAYS FROM THE DATE OF THIS STATEMENT AND THAT THE APPLICANT UNDER SUCH LETTER OF CREDIT HAS FAILED TO PROVIDE A REPLACEMENT LETTER OF CREDIT THAT SATISFIES THE REQUIREMENTS UNDER THE PPL ELECTRIC UTILITIES CORPORATION DEFAULT SERVICE SUPPLIER MASTER AGREEMENT DATED _____ BETWEEN APPLICANT OR AN AFFILIATE OF APPLICANT AND BENEFICIARY. WE THEREFORE DEMAND PAYMENT IN THE AMOUNT OF [INSERT AMOUNT UP TO ENTIRE REMAINING UNDRAWN AMOUNT] PURSUANT TO SUCH AGREEMENT, AND THIS STATEMENT SHALL BE THE NOTICE OF COMPLETENESS FOR THIS PRESENTATION UNDER THE ABOVE-REFERENCED LETTER OF CREDIT."

2. THIS ORIGINAL LETTER OF CREDIT AND ANY AMENDMENT(S).

AT THE BENEFICIARY'S REQUEST PRIOR TO THE EXPIRY DATE, THE ISSUER WILL ISSUE TO THE BENEFICIARY A REPLACEMENT LETTER OF CREDIT (HAVING THE SAME TERMS AND CONDITIONS AS THIS LETTER OF CREDIT AND ANY AMENDMENTS HERETO) IF THE BENEFICIARY CERTIFIES TO THE

ISSUER THAT THE ORIGINAL LETTER OF CREDIT HAS BEEN LOST, STOLEN, DESTROYED OR MUTILATED AND PROVIDES THE ISSUER WITH A REASONABLY ACCEPTABLE INDEMNITY.

PARTIAL AND MULTIPLE DRAWINGS ARE PERMITTED. IN THE EVENT OF ANY PARTIAL DRAWING WE WILL, PROMPTLY FOLLOWING PRESENTATION THEREOF, RETURN THE ORIGINAL LETTER OF CREDIT AND ALL AMENDMENTS TO YOU. ALL AMOUNTS PAID BY US TO BENEFICIARY IN COMPLIANCE WITH THIS LETTER OF CREDIT SHALL CONSTITUTE A PRO TANTO REDUCTION IN THE STATED AMOUNT OF THIS LETTER OF CREDIT.

IF PRESENTATION OF ANY DRAWING IS MADE ON A BUSINESS DAY (AS HEREIN DEFINED) AND SUCH PRESENTATION IS MADE ON OR BEFORE 11:00 A.M. NEW YORK TIME, ISSUER SHALL SATISFY SUCH DRAWING REQUEST ON THE NEXT BUSINESS DAY. IF THE DRAWING IS RECEIVED AFTER 11:00 A.M. NEW YORK TIME, ISSUER WILL SATISFY SUCH DRAWING REQUEST ON THE SECOND FOLLOWING BUSINESS DAY. ALL PAYMENTS MADE UNDER THIS LETTER OF CREDIT SHALL BE MADE BY MEANS OF WIRE TRANSFER IN IMMEDIATELY AVAILABLE UNITED STATES DOLLARS TO YOUR BANK ACCOUNT INDICATED BY BENEFICIARY.

WE HEREBY ENGAGE WITH YOU THAT ALL DOCUMENTS PRESENTED IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE DULY HONORED IF PRESENTED FOR PAYMENT ON OR BEFORE THE EXPIRY DATE, AS EXTENDED FROM TIME TO TIME IN ACCORDANCE WITH THE TERMS OF THIS LETTER OF CREDIT.

IN THE EVENT OF ANY NON-CONFORMING PRESENTATION, WE SHALL IMMEDIATELY NOTIFY BENEFICIARY BY EMAIL TO PPLMARGINCALL2@PPLWEB.COM THAT THE PRESENTATION HAS BEEN REJECTED, WHICH NOTICE SHALL INDICATE THE REASONS FOR DISHONORING SUCH PRESENTATION AND SHALL PLACE AT THE DISPOSAL OF BENEFICIARY THE DOCUMENTS PRESENTED BY BENEFICIARY IN SUPPORT OF ITS DEMAND FOR PAYMENT. BENEFICIARY MAY THEREAFTER PRESENT DOCUMENTS AND RECEIVE PAYMENT HEREUNDER IN THE EVENT A CONFORMING PRESENTATION IS MADE IN ACCORDANCE WITH THE TERMS OF THIS LETTER OF CREDIT.

IT IS A CONDITION OF THIS LETTER OF CREDIT THAT IT WILL BE AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR ONE YEAR FROM THE EXPIRY DATE HEREOF, OR ANY FUTURE EXPIRY DATE, UNLESS AT LEAST 90 DAYS PRIOR TO ANY EXPIRY DATE WE NOTIFY YOU BY EMAIL TO PPLMARGINCALL2@PPLWEB.COM THAT WE ELECT NOT TO

CONSIDER THIS LETTER OF CREDIT RENEWED FOR ANY SUCH PERIOD.

THE TERM "BUSINESS DAY" AS USED HEREIN MEANS ANY DAY OTHER THAN (I) A SATURDAY, (II) A SUNDAY, OR (III) A DAY ON WHICH BANKING INSTITUTIONS LOCATED IN THE CITY OF NEW YORK, NEW YORK ARE REQUIRED OR AUTHORIZED BY LAW TO BE CLOSED.

ADDITIONAL TERMS AND CONDITIONS:

1. ALL COMMISSIONS, FEES, COSTS, AND OTHER BANKING CHARGES WILL BE BORNE BY THE APPLICANT.

2. THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS, 2007 REVISION - ICC PUBLICATION NO. 600, AS SUPPLEMENTED BY THE eUCP VERSION 2.0, OR ANY SUCCESSOR PUBLICATION THERETO (THE "UCP"). AS TO MATTERS NOT GOVERNED BY THE UCP, THIS LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE [COMMONWEALTH OF PENNSYLVANIA; STATE OF NEW YORK], INCLUDING, TO THE EXTENT NOT INCONSISTENT WITH THE UCP, THE UNIFORM COMMERCIAL CODE AS IN EFFECT IN THE [COMMONWEALTH OF PENNSYLVANIA; STATE OF NEW YORK].

3. ARTICLE 36 OF THE UCP AS IT APPLIES TO THIS LETTER OF CREDIT IS MODIFIED AS FOLLOWS: IF, ON THE LAST BUSINESS DAY FOR PRESENTATION THE PLACE FOR PRESENTATION STATED IN THIS LETTER OF CREDIT IS CLOSED FOR ANY REASON, THEN THE LAST DAY FOR PRESENTATION IS AUTOMATICALLY EXTENDED TO THE DAY THAT IS TEN (10) CALENDAR DAYS AFTER THE PLACE FOR PRESENTATION RE-OPENS OR THE ISSUER NOTIFIES THE BENEFICIARY OF AN ALTERNATIVE PLACE FOR PRESENTATION, WHICH ALTERNATIVE MUST BE IN THE UNITED STATES.

4. THIS LETTER OF CREDIT MAY NOT BE AMENDED, CHANGED OR MODIFIED WITHOUT THE EXPRESS WRITTEN CONSENT OF THE BENEFICIARY AND THE ISSUER.

5. THE BENEFICIARY SHALL NOT BE DEEMED TO HAVE WAIVED ANY RIGHTS UNDER THIS LETTER OF CREDIT, UNLESS, AND THEN ONLY TO THE EXTENT THAT, THE BENEFICIARY OR AN AUTHORIZED AGENT OF THE BENEFICIARY SHALL HAVE SIGNED A DATED WRITTEN WAIVER EXPRESSLY WAIVING SUCH RIGHT OR RIGHTS. NO SUCH WAIVER, UNLESS EXPRESSLY SO STATED THEREIN, SHALL

BE EFFECTIVE AS TO ANY TRANSACTION THAT OCCURS SUBSEQUENT TO THE DATE OF THE WAIVER, NOR AS TO ANY CONTINUANCE OF ANY BREACH OR NON-COMPLIANCE AFTER THE WAIVER.

6. A FAILURE TO MAKE ANY DRAWINGS AT ANY TIME SHALL NOT IMPAIR OR REDUCE THE AVAILABILITY OF THIS LETTER OF CREDIT IN ANY SUBSEQUENT PERIOD OR OUR OBLIGATION TO HONOR ANY SUBSEQUENT DEMAND OR DEMANDS FOR PAYMENT MADE IN ACCORDANCE WITH THE TERMS OF THIS LETTER OF CREDIT.

AUTHORIZED SIGNATURE:_____

TITLE: _____

PLEASE DIRECT ANY CORRESPONDENCE (OTHER THAN DRAFTS, DOCUMENTS OR OTHER COMMUNICATIONS REGARDING PRESENTMENT OR NOTICES REGARDING REJECTION OR NON-RENEWAL) TO:

[BANK NAME, EMAIL ADDRESS AND PHONE NUMBER]

EXHIBIT 6 – UNCONDITIONAL GUARANTY

THIS GUARANTY AGREEMENT (this "Guaranty") is made and entered into as of this _____day of _____, by _____ (the "Guarantor"), with an address at _____, in favor of PPL Electric Utilities Corporation (the "Buyer"), with an address at 827 Hausman Rd., 1st Floor, Allentown, PA 18104, in consideration of all Transactions for Default Service, Alternative Energy Credit, Long Term Power, and Block Service under Supplier Master Agreement(s) ("SMA(s)") between PPL Electric Utilities Corporation and _____ (the "Seller"), including but not limited to all transactions under other agreements providing for default service or similar service, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged. Unless otherwise defined herein, all capitalized terms used herein shall have the respective meanings assigned thereto in the applicable SMA(s).

Whereas, Seller is an affiliate of Guarantor, and Guarantor desires Buyer to enter into SMA(s) with Seller and Guarantor's provision of this Guaranty is an inducement for Buyer to be willing to enter into SMA(s) with Seller.

Now, therefore, intending to be legally bound hereby, Guarantor covenants and agrees as follows:

1. Guaranty of Obligations.

(a) The Guarantor hereby irrevocably and unconditionally guarantees as primary obligor and not as a surety, with effect from date hereof, the prompt and complete payment in immediately available funds in the United States when due of all of Seller's obligations (present or future, direct or indirect, secured or unsecured, fixed or contingent and whenever due, whether on scheduled payment dates, upon demand, on a Termination Payment Date or otherwise) under the SMA(s), as well as, all reasonable out-of-pocket costs and expenses incurred by Buyer in the enforcement of the Guarantor's obligations or collection under this Guaranty, including reasonable attorney's fees and expenses (collectively, the "Obligations") provided only that the Buyer is the prevailing party in any judicial suit, action or proceeding arising out of, resulting from, or in any way relating to this Guaranty, or if by mutual agreement by Guarantor and Buyer. [Optional provision: Notwithstanding anything to the contrary herein, the liability of the Guarantor under this Guaranty and Buyer's right of recovery hereunder for all Obligations is limited to a total aggregate amount of $_____ ("Guaranty Amount"), where Guaranty Amount shall be no less than Five Hundred Thousand US Dollars ($500,000).]

(b) The Guarantor shall not be required to pay any consequential, incidental,

punitive, exemplary or indirect damages, lost profits or other business interruption damages except in each case to the extent that they constitute Obligations that are required to be paid under the applicable SMA(s).

2. Nature of Guaranty; Waivers

(a) This is a guaranty of payment and not of collection and the Buyer shall not be required, as a condition of the Guarantor's liability, to proceed first against Seller or any performance assurance or any collateral that Guarantor may hold, or to pursue any rights which may be available to it with respect to any other person or entity who may be liable for the payment of the Obligations. This is not a guaranty of performance (other than of performance of payment obligations) and the Guarantor is not obligated to provide power under the SMA(s) or this Guaranty.

(b) This Guaranty is an absolute, unconditional, irrevocable (subject to the provisions of Section 12 of this Guaranty) and continuing guaranty and will remain in full force and effect until all of the Obligations have been indefeasibly paid in full, or until the SMA(s) have been terminated, whichever comes later. This Guaranty will not be affected by any surrender, exchange, acceptance, compromise or release by the Buyer or any other party, or any other guaranty, performance assurance or other security held by it for any of the Obligations, by any failure of the Buyer to take any steps to perfect or maintain its lien or security interest in or to preserve its rights to any security, performance assurance, or other collateral for any of the Obligations or any guaranty, or by any irregularity, unenforceability or invalidity of any of the Obligations or any part thereof.

(c) Except as to any claims, defenses, or rights of set-off to which Seller is entitled under the SMA(s), exclusive of any claims, defenses, and rights of set-off that are based upon the insolvency, bankruptcy or reorganization of Seller, the power or authority to enter into and perform under the SMA(s) or the Transactions, all of which are expressly reserved under this Guaranty, the Guarantor's obligations hereunder shall not be affected, modified or impaired by any counterclaim, set-off, deduction or defense based upon any claim the Guarantor may have against Seller or the Buyer, including: (i) any change in the corporate existence (including its charter or other governing agreement, laws, rules, regulations or powers), structure or ownership of Seller or the Guarantor; or (ii) any insolvency, bankruptcy, reorganization or other similar proceeding affecting Seller or its assets; or (iii) the invalidity or unenforceability in whole or in part of the SMA(s); or (iv) any provision of applicable law or regulations

purporting to prohibit payment by Seller of amounts to be paid by it under the SMA(s) (other than any law or regulation that eliminates or nullifies the obligations under the SMA(s)).

(d) Guarantor waives notice of acceptance of this Guaranty, diligence, presentment, notice of dishonor and protest and any requirement that at any time Buyer or any other person or entity exhaust any right to take any action against Seller or Seller's assets or any other guarantor, person or entity, and Buyer shall not be bound or obligated to exhaust its recourse against Seller or any other person or entity or against any performance assurance or other collateral it may hold or take any other action before being entitled to receive payment from Guarantor. Any failure of Buyer to give notice shall not discharge, alter or diminish in any way Guarantor's obligations under this Guaranty. The Guarantor waives all claims, defenses, and rights of set-off based on suretyship or impairment of collateral or any other defenses that would constitute a legal or equitable discharge of Guarantor's obligations, except any claims, defenses, or rights of set-off of Seller in respect of its obligations under the SMA(s) that are expressly reserved under Section 2(c) above.

(e) The Buyer at any time and from time to time, without notice to or the consent of the Guarantor, and without impairing or releasing, discharging or modifying the Guarantor's liabilities hereunder, may (i) to the extent permitted by the SMA(s), change the manner, place, time or terms of payment or performance of, or other terms relating to, any of the Obligations; (ii) to the extent permitted by the SMA(s), renew, substitute, modify, amend or alter, or grant consents or waivers relating to any of the Obligations, or any other guaranties for any Obligations; (iii) settle, compromise or deal with any other person, including Seller, with respect to any Obligations in such manner as the Buyer deems appropriate at its reasonable discretion; (iv) substitute, exchange or release any performance assurance or any guaranty; or (v) take such actions and exercise such remedies hereunder or under the SMA(s) as Buyer deems appropriate in its reasonable discretion.

3. Representations and Warranties. The Guarantor hereby represents and warrants that:

(a) it is a [limited liability company, corporation, limited partnership, general partnership] duly organized, validly existing and in good standing under the laws of the jurisdiction of its [formation, organization, incorporation] and has the [corporate power] [power] and authority to conduct the business in which it is currently engaged and enter into and perform its

obligations under this Guaranty;

(b) it has the [corporate power] [power] and authority and the legal right to execute and deliver, and to perform its obligations under, this Guaranty, and has taken all necessary [corporate action] [action] to authorize its execution, delivery and performance of this Guaranty;

(c) this Guaranty constitutes a legal, valid and binding obligation of the Guarantor enforceable in accordance with its terms, subject to applicable bankruptcy, reorganization, insolvency, moratorium or similar laws affecting creditors' rights generally and subject, as to enforceability, to equitable principles of general application (regardless of whether enforcement is sought in a proceeding in equity or at law);

(d) the execution, delivery and performance of this Guaranty will not violate any provision of any requirement of law or contractual obligation of the Guarantor;

(e) no consent or authorization of, filing with, or other act by or in respect of, any arbitrator or governmental authority and no consent of any other person (including, without limitation, any stockholder or creditor of the Guarantor) is required in connection with the execution, delivery, performance, validity or enforceability of this Guaranty, other than any which have been obtained or made prior to the date hereof and remain in full force and effect; and

(f) no litigation, investigation or proceeding of or before any arbitrator or governmental authority is pending or, to the knowledge of the Guarantor, threatened by or against the Guarantor that could reasonably be expected to have a material adverse effect on this Guaranty or Guarantor's ability to perform all of its obligations hereunder.

4. Repayments or Recovery from the Buyer. If any demand is made at any time upon the Buyer for the repayment or recovery of any amount received by it in payment or on account of any of the Obligations, including but not limited to upon the bankruptcy, insolvency, dissolution or reorganization of the Seller and if the Buyer repays all or any part of such amount by reason of any judgment, decree or order of any court or administrative body or by reason of any settlement or compromise of any such demand, the Guarantor shall be and remain liable hereunder for the amount so repaid or recovered to the same extent as if such amount had never been received originally by the Buyer. The provisions of this section will be and remain effective notwithstanding any contrary action which may have been taken by the Guarantor in reliance upon such payment, and any

such contrary action so taken will be without prejudice to the Buyer's rights hereunder and will be deemed to have been conditioned upon such payment having become final and irrevocable. Furthermore, this Guaranty shall continue to be effective or be reinstated, as the case may be, without any release or discharge of any obligations if at any time any payment of any of the Obligations is rescinded, avoided, recovered or must otherwise be returned by Buyer upon the insolvency, bankruptcy, or reorganization of Seller, Guarantor or any other guarantor or any other person or entity or otherwise, all as though such payment had not been made.

5. Enforceability of Obligations. No modification, limitation or discharge of the obligations of Seller arising out of or by virtue of any bankruptcy, reorganization or similar proceeding for relief of debtors under federal or state law will affect, modify, limit or discharge the Guarantor's liability in any manner whatsoever and this Guaranty will remain and continue in full force and effect and will be enforceable against the Guarantor to the same extent and with the same force and effect as if any such proceeding had not been instituted. The Guarantor waives all rights and benefits which might accrue to it by reason of any such proceeding and will be liable to the full extent hereunder, irrespective of any modification, limitation or discharge of the liability of Seller that may result from any such proceeding.

6. Postponement of Subrogation. Guarantor shall not be subrogated to any of the rights (or if subrogated by operation of law, such Guarantor hereby waives such rights to the extent permitted by applicable law) of Buyer as the result of any payment or enforcement of any of the Obligations until all of the SMA(s) have terminated and all Obligations (other than contingent indemnities not then due) have been paid in full (such date, the "Obligations Full Payment Date"). If any amount shall be paid to Guarantor on account of subrogation at any time prior to the Obligations Full Payment Date, such amount shall be held by Guarantor in trust for Buyer, segregated from other funds of Guarantor, and shall, forthwith upon receipt by Guarantor, be turned over to Buyer in the exact form received by Guarantor (duly endorsed by Guarantor to Buyer, if required) to be applied against the Obligations, whether due or to become due, in such order as Buyer may determine. On the Obligations Full Payment Date, Buyer agrees that Guarantor shall be subrogated to the rights of Buyer against Seller to the extent of Guarantor's payments to Buyer hereunder that have not been rescinded, avoided or otherwise required to be returned.

7. Notices. All notices, demands, requests, consents, approvals and other communications required or permitted hereunder must be in writing and will be effective upon receipt. Such notices and other communications may be hand-delivered, sent by email to the address set forth below and confirmed by telephone

to the number set forth below, sent by facsimile transmission with confirmation of delivery and a copy sent by first-class mail, or sent by nationally recognized overnight courier service, to the addresses for the Buyer and the Guarantor set forth below or to such other address as one may give to the other in writing for such purpose:

All communications to Buyer shall be directed to:

Attn: Manager, Credit and Contract Administration
Phone: 502-627-4253
Fax: 502-627-3950
Email: jhearly@pplweb.com
Address: 220 West Main Street, Louisville, KY 40202

or such other address as the Buyer shall from time to time specify to Guarantor by notice given in accordance with this Section 7.

All communications to Guarantor shall be directed to:

Attn: _____
Phone: _____
Fax: _____
Email: _____
Address: _____

or such other address as the Guarantor shall from time to time specify to Buyer by notice given in accordance with this Section 7.

8. Preservation of Rights. No delay or omission on the Buyer's part to exercise any right or power arising hereunder will impair any such right or power or be considered a waiver of any such right or power, nor will the Buyer's action or inaction impair any such right or power. The Buyer's rights and remedies hereunder are cumulative and not exclusive of any other rights or remedies which the Buyer may have under other agreements with the Guarantor or in respect of any performance assurance or at law or in equity.

9. Illegality. In case any one or more of the provisions contained in this Guaranty should be invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

10. Amendments. No modification, amendment or waiver of any provision of this Guaranty nor consent to any departure by the Guarantor therefrom, will be

effective unless made in a writing signed by the Buyer, and then such waiver or consent shall be effective only in the specific instance and for the purpose for which given. No notice to or demand on the Guarantor in any case will entitle the Guarantor to any other or further notice or demand in the same, similar or other circumstance.

11. Entire Agreement. This Guaranty (including the documents and instruments referred to herein) constitutes the entire statement of the terms of this Guaranty and supersedes all other prior agreements and understandings, both written and oral, between the Guarantor and the Buyer with respect to the subject matter hereof.

12. Successors and Assigns. This Guaranty will be binding upon the successors and permitted assigns of Guarantor and inure to the benefit of the Buyer and its successors and assigns. Any assign must meet the requirements of a Guarantor under the SMA. Guarantor shall not assign this Guaranty in whole or in part without Buyer's prior written consent, which consent shall not be unreasonably withheld or delayed, except that this Section 12 shall not limit the Guarantor's right to assign this Guaranty, along with substantially all of the Guarantor's assets and business to a successor entity or Affiliate that concurrently assumes in a writing provided to the Buyer all of Guarantor's obligations hereunder and (i) where the successor Guarantor's Lowest Credit Rating is equal to or greater than the Guarantor's Lowest Credit Rating or where the successor Guarantor's Lowest Credit Rating is equal to or greater than BB-, as rated by Standard & Poor's Financial Services LLC, a part of McGraw-Hill Financial (or its successor) ("S&P") or Fitch Ratings, Inc. (or its successor) ("Fitch"), or Ba3, as rated by Moody's Investors Service, Inc. (or its successor) ("Moody's"), and (ii) the Seller is in compliance with all of its obligations under the SMA(s) before and immediately after giving effect to such assignment and assumption. The "Lowest Credit Rating" shall mean the lowest of the senior unsecured long-term debt ratings (not supported by third-party credit enhancements or, if unavailable, the most current corporate issuer rating) determined by S&P, Moody's or Fitch immediately before such transfer and assumption. Upon any such delegation and assumption of obligations by a successor Guarantor, the Guarantor shall be relieved of and fully discharged from all of its obligations hereunder, whether such obligations arose before or after the date of such delegation and assumption.

13. Interpretation. In this Guaranty, unless the Buyer and the Guarantor otherwise agree in writing, the singular includes the plural and the plural the singular; references to statutes are to be construed as including all statutory provisions consolidating, amending or replacing the statute referred to; the word "or" shall be deemed to include "and/or", the words "including", "includes" and "include" shall be deemed to be followed by the words "without limitation"; and references

to sections or exhibits are to those of this Guaranty unless otherwise indicated. Section headings in this Guaranty are included for convenience of reference only and shall not constitute a part of this Guaranty for any other purpose.

14. Governing Law.

(a) This Guaranty has been delivered to and accepted by the Buyer. THIS GUARANTY SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE COMMONWEALTH OF PENNSYLVANIA, EXCLUDING ITS CONFLICT OF LAWS RULES THAT WOULD APPLY THE LAWS OF ANY OTHER JURISDICTION.

(b) The Guarantor hereby irrevocably consents to the non-exclusive jurisdiction of any federal court in the Commonwealth of Pennsylvania, but in the event that the Guarantor and the Buyer jointly determine in good faith that jurisdiction does not lay with such court or that such court refuses to exercise jurisdiction or venue over the Guarantor and the Buyer or any claims made pursuant to this Guaranty, then the Guarantor agrees to submit to the non-exclusive jurisdiction of the Pennsylvania State courts; provided that nothing contained in this Guaranty will prevent the Buyer from bringing any action, enforcing any award or judgment or exercising any rights against the Guarantor individually, against any security or against any property of the Guarantor within any other county, state or other foreign or domestic jurisdiction. The Guarantor acknowledges and agrees that the venue provided above is the most convenient forum for both the Buyer and the Guarantor. The Guarantor waives any objection to venue and any objection based on a more convenient forum in any action instituted under this Guaranty. The Guarantor agrees that a PDF copy of this Guaranty transmitted to Buyer by electronic means, and maintained by Buyer in electronic form, shall constitute the original Guaranty and be admissible under the rules of evidence in any regulatory proceeding, or in court or other dispute resolution forum.

15. WAIVER OF JURY TRIAL. THE GUARANTOR AND BUYER IRREVOCABLY WAIVE ANY AND ALL RIGHT TO A TRIAL BY JURY IN ANY ACTION, PROCEEDING OR CLAIM OF ANY NATURE RELATING TO THIS GUARANTY, ANY DOCUMENTS EXECUTED IN CONNECTION WITH THIS GUARANTY OR ANY TRANSACTION CONTEMPLATED IN ANY OF SUCH DOCUMENTS. THE GUARANTOR AND BUYER ACKNOWLEDGE THAT THE FOREGOING WAIVER IS KNOWING AND VOLUNTARY.

16. Term. This Guaranty shall survive termination of the SMA(s) and remain in full force and effect until all amounts due hereunder, including all of the Obligations, have been paid in full.

17. Stay of Acceleration Ineffective with Respect to Guarantor. If acceleration of the time for payment of any amount payable by Seller under the SMA(s) is stayed upon the insolvency, bankruptcy or reorganization of Seller, all such amounts otherwise subject to acceleration or required to be paid upon an early termination pursuant to the terms of the SMA(s) shall nonetheless be payable by the Guarantor hereunder on written demand by Buyer.

18. Severability. Any provision contained in this Guaranty which is prohibited or severability in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

19. Electronic Signatures. The electronic signature of Guarantor shall be valid as an original signature of Guarantor and shall be effective to bind Guarantor.

The Guarantor acknowledges that it has read and understood all the provisions of this Guaranty, and has been advised by counsel as necessary or appropriate.

[Guarantor]
By:_____
Name: _____
Title: _____

RBEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	R-2025-3057164
Coalition For Affordable Utility Services	:	
and Energy Efficiency in Pennsylvania	:	C-2025-3057844
Office of Small Business Advocate	:	C-2025-3057889
Office of Consumer Advocate	:	C-2025-3058130
Brad and Jennifer Wooley	:	C-2025-3057946
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Solar Energy Industries Association and	:	C-2025-3058251
The Coalition for Community Solar Access	:	C-2025-3058846
Rik Bhattacharyya	:	C-2025-3058982
Safiya Junaid	:	C-2025-3059151
Stacey Kimmel-Smith	:	C-2025-3059330
John Gadomski	:	C-2026-3060429
Thatcher Graham	:	
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of **CGC Statement No. 1-SRJ and Exhibits 1-SRJ through 3-SRJ** has been served upon the following parties of record in accordance with 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below:

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Dated: March 2, 2026

Daniel A. Garcia (PA Attorney ID 311503)
Counsel for Customer-Generator Coalition

CGC Statement No. 1-SRJ
Witness: Guy Sharfman

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Docket No. R-2025-3057164

SURREJOINDER TESTIMONY OF GUY SHARFMAN

ON BEHALF OF
ASPEN POWER PARTNERS LLC, 38 DEGREES NORTH, BOLLINGER SOLAR, CEP RENEWABLES, LLC, CVE NORTH AMERICA, DYNAMIC ENERGY SOLUTIONS, LLC, EDPR NA DISTRIBUTED GENERATION LLC, ENCORE RENEWABLE ENERGY, GS POWER PARTNERS, PROSPECT14 LLC, RADIAL POWER LLC, SCALE MICROGRIDS, SOLAR RENEWABLE ENERGY, LLC, SR1 CAPTURA SAGE HOLDCO I, LLC, AND SYNCARPHA CAPITAL, LLC (COLLECTIVELY THE "CUSTOMER-GENERATOR COALITION")

CONCERNING:
MAXIMUM REGISTERED PEAK LOAD

MARCH 2, 2026

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SURREJOINDER TESTIMONY OF

GUY SHARFMAN

I. PURPOSE AND SCOPE OF SURREJOINDER

Q: PLEASE EXPLAIN THE PURPOSE OF YOUR SURREJOINDER TESTIMONY IN THIS PROCEEDING.

A: My surrejoinder testimony responds to the rejoinder testimony of PPL Electric Witness, Andrew Castanaro.

Q: ARE YOU OFFERING ANY NEW TARIFF PROPOSALS OR ALTERNATIVE RATE DESIGNS IN THIS SURREJOINDER TESTIMONY?

A: No.

II. CORRECTIONS TO PRIOR MODELING

Q: IN HIS REJOINDER TESTIMONY, MR. CASTANARO STATES THAT HE DISCOVERED CORRECTIONS THAT NEEDED TO BE MADE TO HIS ORIGINAL ANALYSES AND THAT THOSE CORRECTIONS ARE REFLECTED IN EXHIBITS AC-4RJ THROUGH AC-6RJ (STATEMENT NO. 15-RJ, PAGE 2, LINES 1-4; PAGE 3, LINES 1-8). HOW DO YOU RESPOND?

A: Mr. Castanaro admits to making the following errors in his original analysis presented in direct testimony:

1) He used a 0% cancellation rate for customer-generator projects when he meant to use 36%.
2) He used a 29.8% capacity factor for customer-generator projects when he should have used 17.3%.
3) He mistakenly failed to capture the excess generation attributable to Rate LP-4 "no-load" customer-generator projects.
4) He failed to account for the reduction in PPL's default service requirement due to an increase in excess customer generation.

He provides exhibits AC-4RJ, AC-5RJ & AC-6RJ as part of his rejoinder testimony that revise the values provided in his original exhibits AC-1RJ, AC-2RJ & AC-3RJ.

Q: WHAT ARE THE IMPACTS OF MR. CASTARANO'S ANALYSIS REVISIONS?

A: Mr. Castanaro's analysis revisions result in his original values changing significantly in later years. The table below compares the original PTC forecast values provided in PPL

exhibit AC-1RJ to the new PTC forecast values provided in PPL exhibit AC-4RJ. As noted by the table, the impact of Castanaro's revisions result in his 2029 PTC forecast value rising by nearly 50%, while his 2030 PTC projection dropped by almost 90%.

Year	PPL Electric Exhibit AC-1RJ GSC-1 PTC Projection (in $ per kWh)	PPL Electric Exhibit AC-4RJ GSC-1 PTC Projection (in $ per kWh)	DELTA (in %)
2024	$0.11386	$0.11386	0.00%
2025	$0.12114	$0.12114	0.00%
2026	$0.12114	$0.12114	0.00%
2027	$0.12575	$0.12437	(1.10%)
2028	$0.15067	$0.15064	(0.02%)
2029	$0.20474	$0.30562	49.27%
2030	$0.29515	$0.03158	(89.30%)

Q: DOES MR. CASTANARO'S ANALYSIS REVISIONS STRENGTHEN HIS ARGUMENT THAT GSC-1 NON-GENERATOR CUSTOMERS WILL BE HARMED IF THE PPL MRPL PROPOSAL IS REJECTED?

A: No. Mr. Castanaro has yet to establish that anyone would be harmed if the PPL MRPL proposal is rejected.

Q: DO YOU FIND MR. CASTANARO'S LATEST PTC FORECAST VALUES CREDIBLE?

A: No. Mr. Castanaro's PTC projections do not line up with the current wholesale forward market. For example, CGC Exhibit No. 1-SRJ compares PPL's 2027 and 2028 PTC projections under the 36% cancelation scenario to 2027 and 2028 PPL zone forward prices. The exhibit shows that while Mr. Castanaro projects the PTC to rise by 21% from 2027 to 2028 the forward market indicates that 2028 energy prices into the PPL zone actually decline slightly from 2027.

Q: WHY WOULD YOU EXPECT THE PPL PTC TO NECESSARILY FOLLOW THE FORWARD MARKET?

A: PPL procures energy for PTC service from competitive suppliers who price their bids based on the wholesale market. Pennsylvania is also an electric choice state, meaning Pennsylvania electric customers are not trapped by utility service rates the way they are in electric monopoly states. If the PPL PTC significantly exceeds the market cost to supply end users, PPL rate payers would leave PPL and take EGS service at more attractive prices. As such, while I do not anticipate the PPL PTC to approach $300 per MWh over the next 3 years, EGS service will protect PPL customers even if such high PTCs materialized.

Q: MR. CASTANARO CLAIMS THAT INCREASED EGS SWITCHING LEADS TO FEWER CUSTOMERS ON RATE GSC-1 BEING ABLE TO ABSORB PTC COSTS. HOW DO YOU RESPOND?

A: The purpose of Pennsylvania electric choice is to create alternatives to the PTC, not to refine PTC pricing. Increased EGS switching is a sign of a healthy market and should be encouraged.

Q: MR. CASTANARO STATES THAT HE EXPECTS THAT EGS' WOULD INCREASE THEIR RATE OFFERINGS TO CUSTOMERS BASED ON THE INCREASED LEVEL OF THE PTC. DO YOU AGREE WITH HIM?

A: No. While EGS' compete against PPL, they also compete against one another. That means that if any EGS charges a premium for service to match an increased PTC, they leave themselves open to being undercut by another EGS.

Q: IS THERE EVIDENCE THAT EGS PRICING DOES NOT SIMPLY FOLLOW THE PTC?

A: Yes. Intelometry prepares monthly reports that compare utility PTCs to EGS offers for all U.S. deregulated electric markets. Our latest report for Pennsylvania is provided as CGC Exhibit No. 2-SRJ. The exhibit compares the residential PTCs of Pennsylvania electric utilities to publicly available EGS offers posted on the Commission website at www.papowerswitch.com. As illustrated by the exhibit, the lowest competitive offers posted in January 2026 are 11% to 29% lower than the PTC depending on utility. The lowest offer in PPL's service territory is 24% lower than the PPL PTC. There would be a much tighter spread if EGS' simply moved their prices to match the PTC price level.

III. CLAIMED PTC INCREASES AND "CATASTROPHIC" IMPACTS

Q. MR. CASTANARO TESTIFIES THAT THE CORRECTED ANALYSES SHOW THE PTC RISING TO $0.29980 PER KWH UNDER THE 36% CANCELLATION RATE SCENARIO AND DESCRIBES POTENTIAL "CATASTROPHIC IMPACTS" (STATEMENT NO. 15-RJ, P. 5, LL. 8-13). DOES THE RECORD DEMONSTRATE THAT SUCH OUTCOMES ARE LIKELY UNDER REALISTIC PROCUREMENT ADJUSTMENTS?

A. Exhibit AC-4RJ shows the PTC under the 36% cancellation scenario rising to $0.30562, not the $0.29980 value Mr. Castanaro refers to in testimony. It is not clear why Mr. Castanaro's exhibit and testimony values differ. Neither the testimony nor exhibit value, however, is likely to materialize and wouldn't harm customers even if they did materialize.

Q. WHY DO YOU SAY THAT MR. CASTANARO'S EXTREME PTC PROJECTIONS ARE UNLIKELY TO MATERIALIZE?

A. As previously stated, there is no indication from the wholesale market that 2029 PTCs would run anywhere near $0.30 per kWh or $300 per MWh. Other mainstream industry projections illustrate the same. CGC Exhibit No. 3-SRJ shows the most recent Electric Power Projections by Electricity Market Module Region report 54.10 form the Energy Information Administration ("EIA") for PJM East. The exhibit also compares the movement of EIA generation price projections to PTC prices projected by Mr. Castanaro. As illustrated by the exhibit, the EIA anticipates regional generation prices to rise 10% in 2028, 1% in 2029 and another 1% in 2030. By contrast, Mr. Castanaro projects prices to rise by 17% in 2028, rise by another 51% in 2029 and then massively drop in 2030 by 868%. Given that both wholesale market benchmarks and EIA analysis expect generation prices to remain stable from 2028 to 2030, I simply don't see a $300 PTC materializing. That said, if PTC prices greatly exceeded the market cost to supply, customers would leave PPL for EGS services that are less expensive and provide more benefits to consumers than the PPL PTC would, should that scenario materialize.

Q. WHY DO YOU SAY THAT MR. CASTANARO'S EXTREME PTC PROJECTIONS WON'T HARM CUSTOMERS EVEN IF THEY COME TO FRUITION?

A. A signature benefit of a competitive electric market is that customers are not forced to remain on electric utility service rates they don't like. If the PPL PTC exceeds the market cost to supply PPL customers, then PPL customers would leave PPL for EGS service.

IV. EXTREME $1.32804/KWH SCENARIO

Q: MR. CASTANARO EXPLAINS THAT UNDER ONE SCENARIO, THE PTC AS OF MAY 31, 2030 WOULD REACH $1.32804 PER KWH (STATEMENT NO. 15-RJ, P. 8, LL. 1-4). DOES THE REJOINDER IDENTIFY THIS AS A BASE CASE FORECAST OR A STRESS-CASE SCENARIO?

A: This value represents Mr. Castanaro's PTC projection for 2029 under the 50% cancelation scenario.

Q: IS THIS PROJECTION CREDIBLE?

A: No. A $1.32804 PTC equates to over $1,300 a MWh. There are no market or industry benchmarks projecting retail generation prices to climb that high by 2029. Further, Mr. Castanaro's 2029 projected PTC value of approximately $300 per MWh under the 36% cancelation scenario is substantially lower. This contradicts PPL's position that lower cancelation rates result in higher PTCs.

Q: MR. CASTANARO ATTRIBUTES THIS SPIKE TO RECONCILIATION OF EXCESS GENERATION COMPENSATION (STATEMENT NO. 15-RJ, P. 8, LL. 5-13). DOES THE TESTIMONY ACCOUNT FOR BEHAVIORAL RESPONSES BY CUSTOMERS, SUPPLIERS, OR PROCUREMENT ADMINISTRATORS?

A: No. If PPL were to charge $1.32804 per kWh PTC to GSC-1 customers when the market cost to supply those same customers is much less, there would be a mass exodus of PPL customers to EGS service.

V. CAUSATION AND EVIDENCE OF HARM

Q: MR. CASTANARO STATES THAT PPL ELECTRIC HAS "PUT FORWARD THAT EVIDENCE" DEMONSTRATING HARM (STATEMENT NO. 15-RJ, P. 12, LL. 1-4). DOES THE REJOINDER PRESENT HISTORICAL DATA SHOWING MEASURABLE HARM TO NON-CUSTOMER-GENERATORS UNDER THE CURRENT GSC-1 TARIFF?

A: No.

Q: MR. CASTANARO REJECTS YOUR PRIOR STATEMENT THAT THERE IS NO RECORD EVIDENCE ESTABLISHING A CAUSAL LINK (STATEMENT NO. 15-RJ, P. 12, LL. 4-6). HOW DO YOU RESPOND?

A: Mr. Castanaro states in his rejoinder testimony that values presented in his direct testimony are invalid. So, Mr. Castanaro agrees with me, at least as far as his direct testimony is concerned. Regarding Mr. Castanaro's analysis revisions, I find that the wholesale market and other industry sources do not support his PTC projections. Finally, let me reiterate that Pennsylvania is an electric choice state. Any customer that does not like the PPL PTC can switch to EGS.

VI. RECLASSIFICATION SCOPE – "18 PROJECTS"

Q: MR. CASTANARO REFERENCES THE NUMBER OF PROJECTS THAT WOULD BE AFFECTED BY MRPL AND RESPONDS TO CONCERNS REGARDING SCOPE (STATEMENT NO. 15-RJ, P. 12, L. 8 THROUGH P. 13, L. 7). DOES THE REJOINDER IDENTIFY THE SPECIFIC PROJECTS INCLUDED IN THAT ESTIMATE?

A: No.

Q: DOES THE TESTIMONY CLARIFY WHETHER THE ESTIMATE INCLUDES PROJECTS CURRENTLY IN THE INTERCONNECTION QUEUE BUT NOT YET OPERATIONAL (STATEMENT NO. 15-RJ, P. 12-13)?

A: No.

VII. CAPACITY COMPONENT UNDER GSC-2

Q: MR. CASTANARO STATES THAT PPL WOULD BE WILLING TO INCORPORATE A CAPACITY COMPONENT INTO THE NET METERING COMPENSATION CALCULATION FOR RATE GSC-2 AS PART OF A COMPLIANCE FILING (STATEMENT NO. 15-RJ, P. 11, LL. 14-16). DOES THIS STATEMENT QUANTIFY THE PROPOSED CAPACITY COMPONENT?

A: No.

Q: DOES THE REJOINDER DEMONSTRATE THAT INCLUSION OF A CAPACITY COMPONENT WOULD RENDER RECLASSIFIED GSC-1 PROJECTS ECONOMICALLY NEUTRAL RELATIVE TO CURRENT TREATMENT?

A: No.

VIII. LEGISLATIVE AND POLICY REFERENCES

Q. MR. CASTANARO REFERENCES THE POSSIBILITY THAT LEGISLATION COULD PROHIBIT GENERATING FACILITIES WITH NO INDEPENDENT LOAD FROM PARTICIPATING IN NET METERING (STATEMENT NO. 15-RJ, P. 13, LL. 1-3). IS SPECULATIVE FUTURE LEGISLATION A BASIS FOR MODIFYING EXISTING COMMISSION-APPROVED TARIFFS IN THIS PROCEEDING?

A: No.

IX. CONCLUSION

Q. BASED ON THE CORRECTIONS AND UPDATED ANALYSES PRESENTED IN PPL ELECTRIC STATEMENT NO. 15-RJ, HAS PPL DEMONSTRATED MEASURABLE, PRESENT HARM TO NON-CUSTOMER-GENERATORS UNDER THE EXISTING GSC-1 TARIFF?

A. No.

Q. IN YOUR OPINION, DOES THE RECORD AS SUPPLEMENTED BY STATEMENT NO. 15-RJ SUPPORT APPROVAL OF PPL'S MRPL PROPOSAL?

A. No.

Q. DOES THIS CONCLUDE YOUR SURREJOINDER TESTIMONY?

A. Yes.

CGC Exhibit No. 1-SRJ
Witness: Guy Sharfman

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Docket No. R-2025-3057164

EXHIBIT TO ACCOMPANY SURREJOINDER TESTIMONY OF GUY SHARFMAN

ON BEHALF OF
ASPEN POWER PARTNERS LLC, 38 DEGREES NORTH, BOLLINGER SOLAR, CEP RENEWABLES, LLC, CVE NORTH AMERICA, DYNAMIC ENERGY SOLUTIONS, LLC, EDPR NA DISTRIBUTED GENERATION LLC, ENCORE RENEWABLE ENERGY, GS POWER PARTNERS, PROSPECT14 LLC, RADIAL POWER LLC, SCALE MICROGRIDS, SOLAR RENEWABLE ENERGY, LLC, SR1 CAPTURA SAGE HOLDCO I, LLC, AND SYNCARPHA CAPITAL, LLC (COLLECTIVELY THE "CUSTOMER-GENERATOR COALITION")

CONCERNING:
MAXIMUM REGISTERED PEAK LOAD

MARCH 2, 2026

CGC Exhibit 1-SRJ

Intelometry Market Savings Report for January 2026

Market Data Export Date:	02/27/2026

Month	Amerex Forward Price PPL Zone ATC (in $ per MWh)	Amerex Forward Price PPL Zone ATC (in $ per kWh)
1/1/2027	$84.54	$0.08454
2/1/2027	$71.43	$0.07143
3/1/2027	$38.80	$0.03880
4/1/2027	$36.57	$0.03657
5/1/2027	$31.22	$0.03122
6/1/2027	$37.75	$0.03775
7/1/2027	$60.06	$0.06006
8/1/2027	$50.27	$0.05027
9/1/2027	$37.57	$0.03757
10/1/2027	$40.93	$0.04093
11/1/2027	$43.79	$0.04379
12/1/2027	$58.42	$0.05842
1/1/2028	$83.99	$0.08399
2/1/2028	$70.79	$0.07079
3/1/2028	$39.12	$0.03912
4/1/2028	$36.73	$0.03673
5/1/2028	$32.39	$0.03239
6/1/2028	$37.51	$0.03751
7/1/2028	$59.15	$0.05915
8/1/2028	$50.98	$0.05098
9/1/2028	$36.95	$0.03695
10/1/2028	$41.02	$0.04102
11/1/2028	$43.85	$0.04385
12/1/2028	$58.41	$0.05841

Year	PPL Exhibit AC-4RJ GSC-1 PTC Projection (in $ per kWh)	Amerex Average Annual Forward Price PPL Zone ATC (in $ per kWh)
2027	$0.12437	$0.04928
2028	$0.15064	$0.04924
% Increase	21%	0%

CGC Exhibit No. 2-SRJ
Witness: Guy Sharfman

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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CONCERNING:
MAXIMUM REGISTERED PEAK LOAD

MARCH 2, 2026

CGC Exhibit 2-SRJ

January 2026 Intelometry Market Savings Report for Pennsylvania

All Offers									Fixed Price Offers						Variable Price Offers			Green Offers		
Jan-26	Price to Compare "PTC" ($/kWh) [4]	Price to Compare ""PTC" Effective Date [5]	Lowest Offer ($/kWh)	Customer Savings ($/kWh)	Potential Market Savings for the Month (Total $)	# of Offers	Offers Below PTC	Recorded Date	# of Offers	Offers Below PTC	Longest Term Lowest Offer [3] (bill cycles)	($/kWh)	Lowest Offer (bill cycles)	($/kWh)	# of Offers	Offers Below PTC	Lowest Offer ($/kWh)	# of Offers	Offers Below PTC	Lowest Offer ($/kWh)
MARKETS																				
Pennsylvania					$99,434,472															
Duquesne	$0.13746	12/1/25 - 5/31/26	$0.09810	$0.03936	$11,734,006	106	21	1/28/26	60	8	36	$0.15780	12	$0.12440	5	2	$0.12999	41	11	$0.09810
MetEd	$0.12965	12/1/25 - 5/31/26	$0.10090	$0.02875	$14,508,511	99	6	1/28/26	55	2	36	$0.14680	10	$0.12150	7	2	$0.12599	37	2	$0.10090
PECO	$0.11024	12/1/25 - 2/28/26	$0.08720	$0.02304	$21,308,792	102	6	1/28/26	51	3	36	$0.11990	10	$0.10090	7	2	$0.09990	44	1	$0.08720
Penelec PA	$0.11747	12/1/25 - 5/31/26	$0.10490	$0.01257	$4,517,161	97	7	1/28/26	55	2	36	$0.13850	3	$0.11600	5	3	$0.10490	37	2	$0.10740
Penn Power	$0.12606	12/1/25 - 5/31/26	$0.10490	$0.02116	$2,539,475	88	4	1/28/26	50	1	36	$0.14650	6	$0.12490	5	2	$0.11900	33	1	$0.10490
PPL	$0.12953	12/1/25 - 5/31/26	$0.09790	$0.03163	$36,078,849	103	9	1/28/26	51	3	36	$0.14450	3	$0.11250	11	4	$0.11950	41	2	$0.09790
West Penn Power	$0.10947	12/1/25 - 5/31/26	$0.08990	$0.01957	$8,747,679	102	10	1/28/26	58	5	36	$0.13350	3	$0.09650	7	4	$0.09600	37	1	$0.08990

State	REP	Add-On Service Description
Pennsylvania	AEP Energy	Receive up to $180 Reward Dollars to use in AEP Energy Reward Store, our one-stop online marketplace filled with a variety of energy-saving products for your home.
	Agway Energy Services LLC	Includes our EnergyGuard repair program and provides Peace of Mind repair protection on your central a/c unit and the interior electric lines in your home.
	Alpha Gas and Electric LLC	Free month of energy supply after a year of service.
	American Power & Gas of Pennsylvania LLC	Our famous 25% rebate is available to all of our customers.
	Atlantic Energy MD LLC	Free Smart Home Products (color changing bulbs, security cameras with 2-way talk, smart plugs, and more). 3% Cash Back
	City Power & Gas PA	$25 in Reward Dollars every month and an annual 2% Cashback Reward.
	EcoPlus Power LLC	Complimentary Norton LifeLock Personal Identity Theft Protection Subscription (Valued over $300 annually). Amazon Gift Card every 6 months of uninterrupted service.
	IDT Energy, Inc.	Earn REWARD points for every kWh used and redeem them for gift cards and more.
	Major Energy	For the $100 rebate, redeem the first $50 after one month of service and the second $50 after 6 months of service from Major.
	NRG Home	1% Cash Back after every 12 months of service.
	nTherm LLC	20% rebate on the average months energy supply cost after 12 consecutive months with nTherm.
	Pennsylvania Gas & Electric	$50 in Reward Dollars every month once your account's active.
	RPA Energy dba Green Choice Energy	As a customer, you qualify for our Power Perks Rewards Program.
	Santanna Energy Services	Enter gift card and tech giveaways with Santanna Rewards! After 60 days of billed usage, we'll make a donation to a nonprofit organization in the Midwest.
	SFE Energy Pennsylvania, Inc.	Will plant 1 tree on your behalf. Earn $50 in rewards dollars each month.
	Shipley Energy	Earn 3% REWARDS with Shipley Energy's Rewards Program.
	Spring Power & Gas	Customers receive $25 in Spring Rewards Dollars each month.
	Think Energy	Sign up and receive a $100 gift card.
	Verde Energy USA, Inc.	$100 in digital Home Depot Gift Cards, by enrolling in a 100% renewable energy credits supply plan with a fixed rate for 12 months.
	WGL Energy Services	$50 in Reward Dollars every month that you can use to save in over 500,000 ways.

State	Utility	Rate Schedule	Number of Residential Customers	Utility Load Profile Assigned	Monthly kWh by Profile	Total Monthly kWh	Sources		Notes
Pennsylvania	Duquesne	Rate Schedule RS	551,224	RS: Residential Service	298,104,914	298,104,914	Rate Schedule: Utility Tariff		1) Green Offers, defined as those with green provisions exceeding the state minimum, are not included in Fixed and Variable offer analysis
	MetEd	Rate RS	535,185	RSNH: Residential Service - No Electric Heat	943	504,643,851	Offers taken from PA Power Switch	www.papowerswitch.com/	2) # of Fixed, Variable, and Green Offers for this analysis excludes any offers containing Enrollment Fees, Monthly Service Fees, Daily Service Fees, Introductory Fees, or are not available until the following month.
	PECO	Rate R	1,532,014	R112: Residential - Average Monthly 451- 800 kWh	604	924,860,774	Number of Residential Customers:	https://www.oca.pa.gov/electric-shopping-guide-2/	3) GRT embedded in Utility PTC rate and retail offers
	Penelec PA	Rate RS	502,520	RSNH: Residential Service - No Electric Heat	715	359,360,422		http://www.oca.state.pa.us/Industry/Electric/elecstats/ElectricStats.htm	4) Total Monthly kWh for DQE = Monthly kWh by Profile
	Penn Power	Rate RS	151,344	RG: Residential-General	793	120,013,015			5) Total Monthly kWh for all other utilities = Number of Residential Customers x Monthly kWh by Profile
	PPL	Schedule RS	1,290,601	RS-GRS: RESIDENTIAL SERVICE - NON-ELEC HEAT	884	1,140,652,814			6) Offers classified by PUC as Variable with Term listed as 'No term length' are assumed to have a term of 1 month
	West Penn Power	Rate RS	638,051	RSNH: Residential Service - No Electric Heat	701	446,994,323			

CGC Exhibit No. 3-SRJ
Witness: Guy Sharfman

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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CONCERNING:
MAXIMUM REGISTERED PEAK LOAD

MARCH 2, 2026

CGC Exhibit 3-SRJ

Latest EIA 54.10. Electric Power Projections by Electricity Market Module Region PJM – EAST

Highlighted Row Shows Nominal Generation prices in Cents per kWh

ref2025.d032025a																		
	Report	Annual Energy Outlook 2025																
	Scenario	ref2025	Reference															
	Datekey	d032025a																
	Release Date	April 2025																
54.10. Electric Power Projections by Electricity Market Module Region																		
10 - PJM / East																		
Electricity Supply and Demand	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Prices by Service Category																		
(nominal cents per kilowatthour)																		
Generation	6.6	6.5	6.4	4.8	5.3	5.3	5.4	5.9	5.8	6.3	6.3	6.3	6.0	6.5	6.4	6.1	6.1	6.3
Transmission	2.24	2.35	2.52	2.68	2.85	3.01	3.16	3.31	3.45	3.61	3.76	3.89	4.02	4.17	4.34	4.48	4.63	4.76
Distribution	4.9	5.0	5.2	5.3	5.5	5.6	5.8	5.9	6.1	6.2	6.4	6.5	6.7	6.9	7.0	7.2	7.3	7.5

Projected Price Movement – PPL PTC v EIA Generation Forecast – 2027 to 2028

Year	PPL Electric Exhibit AC-4RJ GSC-1 PTC Projection		EIA 54.10. Electric Power Projections by Electricity Market Module Region	
	(in $ per kWh)	% Change from Previous Year	(in $ per kWh)	% Change from Previous Year
2027	$0.12437		$0.04843	
2028	$0.15064	17%	$0.05253	8%
2029	$0.30562	51%	$0.05293	1%
2030	$0.03158	(868%)	$0.05359	1%

VERIFICATION

I, GUY SHARFMAN, hereby state that the facts above set forth are true and correct (or are true and correct to the best of my knowledge, information and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Dated: March 2, 2026

Guy Sharfman

Guy Sharfman
Expert Witness for Customer-Generator Coalition

CGC Statement No. 1-SSRJ
Witness: Guy Sharfman

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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SUR-SURREJOINDER TESTIMONY OF GUY SHARFMAN

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CONCERNING:
MAXIMUM REGISTERED PEAK LOAD

MARCH 6, 2026

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SUR-SURREJOINDER TESTIMONY OF
GUY SHARFMAN

I. PURPOSE AND SCOPE OF SUR-SURREJOINDER

Q: PLEASE STATE YOUR NAME AND THE PURPOSE OF YOUR SUR-SURREJOINDER TESTIMONY.

A: My name is Guy Sharfman. I am a co-Founder and Vice President with Intelometry, Inc., a retail electric market systems, data and consulting company. The purpose of my testimony is to respond to select Sur-Rejoinder Testimony.

Q: ARE YOU RESPONDING TO CERTAIN STATEMENTS MADE IN THE SUR-REJOINDER TESTIMONY OF THE OFFICE OF SMALL BUSINESS ADVOCATE ("OSBA")?

A: Yes.

II. RESPONSE TO OSBA STATEMENT NO. 1-SRJ, MARK D. EWAN

Q: OSBA CHARACTERIZES CERTAIN CUSTOMER-GENERATORS EXPORTING ELECTRICITY AS "MERCHANT GENERATORS." IS "MERCHANT GENERATOR" A DEFINED CUSTOMER CLASS IN PPL ELECTRIC UTILITIES' COMMISSION-APPROVED TARIFF?

A: No.

Q: DO NET-METERED CUSTOMER-GENERATORS REMAIN RETAIL CUSTOMERS TAKING SERVICE UNDER COMMISSION-APPROVED RETAIL RATE SCHEDULES?

A: Yes.

Q: OSBA SUPPORTS PPL'S PROPOSAL TO REDEFINE MAXIMUM REGISTERED PEAK LOAD ("MRPL") BASED IN PART ON "NET POWER FLOW." WOULD THAT APPROACH ALLOW EXPORTED GENERATION TO INFLUENCE A CUSTOMER'S RETAIL SERVICE CLASSIFICATION?

A: Yes.

Q: HOW DOES THE PENNSYLVANIA UTILITY CODE DEFINE "MAXIMUM REGISTERED PEAK LOAD"

A: Pennsylvania Code 54.182 defines MRPL as "The highest level of demand for a particular customer, based on the PJM Interconnection, LLC "Peak Load Contribution Standard" or its equivalent, and as may be further defined by the EDC tariff in a particular service territory."

Q: DOES THIS DEFINITION INCLUDE "GENERATION" OR "EXPORT"?

A: No. MRPL is a demand-based value, not a generation-based value.

Q: DOES THE PJM PEAK LOAD CONTRIBUTION ("PLC") FORMULAE CONTAIN "GENERATION" OR "EXPORT"?

A: No. PJM does not allow PLCs to go negative precisely because generation is not involved in setting the PLC value.

Q: DOES THE PENNSYLVANIA NET-METERING FRAMEWORK EXPRESSLY CONTEMPLATE THAT CUSTOMER-GENERATORS MAY EXPORT EXCESS ELECTRICITY TO THE GRID?

A: Yes.

Q: DO CUSTOMER-GENERATORS MEET THE DEFINITION OF "DEFAULT SERVICE SUPPLIERS" AS DEFINED IN THE PPL DEFAULT SERVICE CONTRACT?

A: No. According to PPL's Default Supplier Agreement, a Default Service Supplier must:

1) have been selected through the Default Service Supplier Solicitation;
2) accepted the obligations and associated rights to provide Default Service Supply to PPL for Default Service Customers;
3) has entered into the PPL Default Supplier Agreement.

Customer-generators do not meet this criterion.

Q: IN YOUR OPINION, DOES THE FACT THAT A CUSTOMER EXPORTS EXCESS GENERATION TRANSFORM THAT RETAIL CUSTOMER INTO A "MERCHANT GENERATOR"?

A: No.

Q: IN YOUR OPINION, DOES THE GSC-2 SOLAR CREDIT COMPENSATE CUSTOMERS-GENERATORS THE "FULL RETAIL RATE" SIMILAR TO WHAT IS PROVIDED IN "GSC-1"?

A: No. The PPL GSC-2 solar credit omits capacity, even though capacity is charged for in the GSC-2 PTC. PPL witness Castanaro acknowledged this in rejoinder testimony, stating that "PPL Electric would be willing to incorporate a capacity component to the net metering compensation calculation for Rate GSC-2 customer-generators as part of its compliance retail tariff filing in this case." However, PPL has not provided detail on how the capacity credit component will be derived and assessed to customer-generators.

III. CONCLUSION

Q: BASED ON OSBA'S SUR-REJOINDER TESTIMONY, DO YOU HAVE ANY REASON TO CHANGE THE CONCLUSIONS YOU PREVIOUSLY PRESENTED IN THIS PROCEEDING?

A: No.

Q. DOES THIS CONCLUDE YOUR SUR-SURREJOINDER TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
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Solar Energy Industries Association and	:	C-2025-3058251
The Coalition for Community Solar Access	:	
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058983
Stacey Kimmel-Smith	:	C-2025-3059151
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

DIRECT TESTIMONY
OF JAMES HARBACH
ON BEHALF OF THE PROFESSIONAL DAIRY MANAGERS
OF PENNSYLVANIA

PDMP Statement No. 1
December 22, 2025

Q. Please state your name and business address.

A. My Name is James Harbach, I partner with my family in the ownership and operation of Schrack Farms in Loganton, Clinton County Pennsylvania. The business address is 694 W Valley Way, Loganton, Pa, 17747.

Q. Describe Schrack Farms?

A. Shrack Farms is a family-owned Dairy Farm that has been owned and operated by the Schrack family for over 250 years. That makes me the 9th generation, and I proudly work alongside the 10th and 11th generations. We milk 1400 cows and farm over 2500 acres and are part of a farmer cooperative called Dairy Farmers of America.

Q. What is your interest in the rate case – why are you testifying?

A. As part of its rate case, PPL has proposed to change the way it classifies customers for purposes of default service. It proposes to define generation as demand so that customer generators, like Schrack Farms, will be classified for purposes of default service procurement class, by their generation or consumption, not just on their consumption as has always been done in the past. This change will have the effect of pushing Schrack Farms from a small customer procurement class (GSR-1) to a large customer procurement class (GSR-2) which will cause our price to compare to go from a fixed retail rate at around 12 cents/kWh to a variable wholesale rate at around 6 cents per kWh. This reduction in our price to compare will reduce the compensation we receive for our excess generation and will cause immediate and devastating financial harm to our farm and the farms of other members of the Professional Dairy Managers of Pennsylvania, that have supported our participation in this case.

Q. Explain the process you use to produce electricity using the digester?

A. The manure from our dairy is collected multiple times per day. The manure goes into the digester vessel which heats the manure to 100 degrees to allow microbes to break down the liquid, thus releasing methane. The methane is captured to run an engine/generator producing electricity to be sold to the grid, via a bi-directional meter, to power neighboring houses and businesses. The manure leaves the digester after 2-3 weeks. We separate the solids which are dried and used as bedding for our cows. The liquid portion is spread as higher quality fertilizer for the crops growing to feed the cows. The process is in constant operation, and with our new generator, we have an uptime of approximately 98%. We also capture the waste heat from the generator and 100% of our energy needs for the entire operation are provided.

Q. What is your electrical output onto the grid – kWh per month?

A. We recently, in March 2025, invested in a new, 425 kW generator. Our demand is approximately 300 kW in the summer and 90 kw in the cooler months. Which means that we will export approx. 200,000 kWh/month in the cooler months and 70,000 kWh/month in the summer months.

Q. What are the benefits of the digester technology you use?

A. Anaerobic digesters are the solution to a problem that all dairy farms have, managing manure. We are heavily regulated and this technology is an extremely efficient and effective way to address environmental concerns IF the financial model to keep them running is sustainable. Not only are we able to substantially reduce our carbon footprint by capturing and using methane that otherwise would have gone into the atmosphere, but

the digester output creates more bi-available waste products that we then apply to our crops as a high-quality fertilizer, but without the odor that offends non-farming neighbors. Milk is a price-controlled commodity so our margins can be very slim at times. The efficiency the digester gives us by replacing costly inputs like chemical fertilizer, compost and bedding with even better quality ones that are natural, higher quality made from the waste our cows generate, is essential to the financial stability of our farm. A dairy farm's ability to grow is directly related by their ability to manage and safely dispose of the substantial animal waste that they produce. The digester allows us to care for our cows, grow our herd, and continue to operate our family business, all while complying with stringent environmental regulations and customer demands.

Q. If you did not have the digester in operation, what are your alternatives for waste disposal ?

A. If we did not have the digester, we would be forced to spread the manure directly onto the fields as a smellier and less effective fertilizer. Digesters change the organic nitrogen in manure to an inorganic form allowing it to be more bio-available to the plants. The difference in smell between digested manure and non-digested manure is tenfold, which makes a huge improvement for our neighbors. The alternative for the significant amount of manure our cows generate would not be good for the community and we would miss out on all the operational benefits from the post digested bi-products that are generated.

Q. Is there any benefit from not using the digester versus what you do today?

A. No, if we could not operate the digester, we could not operate the way we do today in terms of the number of cows or the productivity of our crops, and the community would have good reason to complain about the smell.

Q. What is your investment in the digester and related equipment?

A. We have very significant investment in our digester and related equipment. Since 2006 when we installed the digester, with all upgrades, including the recent installation of a new generator, we have invested over $2.3 million of capital in the digester and related equipment.

Q. Were you able to obtain grants to offset any of the costs?

A. We received a Pennsylvania Energy Harvest Grant for approximately three hundred thousand dollars that we used to offset a portion of the initial capital costs. But our family has borne the vast majority of the cost. We also are participating in PPL' Energy Efficiency and Conservation program and stand to receive an approximate two hundred and fifty thousand dollar incentive as part of our system upgrade earlier this year.

Q. How long have you been operating a digester on your farm?

A. We built our digester in 2006.

Q. How many people do you employ?

A. We employ 24 individuals, about 50% of which are multi-generational members of our family.

Q. How many cows do you milk?

A. We have 1400 cows producing the manure that goes through the digester.

Q. How many acres do you farm?

A. We farm over 2500 acres (~ 4 square miles) in corn, grasses, soy beans, and small grains used to feed the cows

Q. What PPL rate class or classes are you taking service under now?

A. The digester and some associated equipment as well as the newer barns and milking parlor are at a 3 phase commercial rate – GS-3. The older barns and the farmhouse are on a residential meter.

Q. Have there been any problems with PPL with regard to the digester and the net metering?

A. It would take less time to tell about when there has not been a problem with PPL regarding the digesters and net metering. In fact, I testified once before when they approached the PUC about changing the net metering and in lieu of success, they have continued to water down the value they pay for the energy we generate by every means possible, including having us bear their costs to upgrade their local transmission lines, testing and other things they require to take green energy. As an example, we had to spend $100,000 to upgrade PPL's line, just to get permission to connect the new generator, with no other changes. So, they're getting infrastructure paid for by my family farm.

Q. Did you need to interact with PPL when you replaced your generator earlier this year?

A. We've been interacting with PPL on this project for at least three years, that's how long it has taken to be allowed to upgrade our old engine. They made us pay for a 3rd party inspection, which they require to connect, and which they used to supply and we were forced to waste 6 months export potential just waiting to get the parallel connection to their system. We often reached out to PPL on this project only to hear nothing back for months and it cost us at every turn. PPL treats us as a burden even though we are required to pay for all of the costs of interconnection.

Q. Did PPL inform you, then or at any time since, that they would be filing a rate case that would substantially reduce your compensation for net metering?

A. They have yet to inform us of their filing to change the rate for which we would be paid, let alone tell us of their intent. The way they slipped in this definition change for small generators like ours within a larger rate increase request might have been by design and we are lucky that someone noticed it and brought it to our attention. Had we known their intent, we would not have even upgraded the old motor. Even at the current rate, the bank was concerned about the payback timeline, so at this proposed rate, we couldn't have gotten the loan. We've been blindsided.

Q. What percentage of your consumption of electricity is offset by your production using biogas produced by the digester?

A. We offset 100% of our electric consumption at the meter associated with the digester with the power it produces. But we do not virtually net meter for the other meter on the property that serves the farmhouse and other barns and so that usage is not offset.

Q. What does that mean for PPL?

A. They pay us less than the price to compare for the electricity that we put onto the distribution system. It means that in the summer, when the grid is stressed, we are taking 300 kW of demand off of the distribution system and actually adding generation to support it. Likewise, in the colder months, we supply even more electricity that is used by our neighbors instead of PPL having to burden the transmission system to import it from elsewhere. I understand that by doing so, we reduce the capacity obligation for all other customers which reduces the transmission cost for all of them.

Q. Were you encouraged by the government and/or supported when you decided to employ the digester technology in 2006?

A. The PA Harvest grant we received was specifically offered to encourage farms to employ digesters and the state and federal government has continued to go to great lengths and costs to get farms to embrace the technology, much to the power companies' dismay. Government officials, including this current Governor's Administration have been showcasing PA dairies to tout its mission for green energy generation in the Commonwealth and our dairy customers are demanding environmental stewardship from those of us who produce their milk.

Q. With all the moving parts – the cost of operating the digester versus the revenue it produces – do you financially break even?

A. We installed the digester to address the environmental impact of the main by-product of dairy farming – manure. If we cannot deal with manure in an environmentally sound and financially sustainable way, we cannot maintain or expand our operation. The digester is

the essential tool for managing manure and if we don't earn income from the electricity sales, it would be a crushing burden on our operations. It would be hard to put a dollar value to the odor reduction the digester provides but it is significant, and other benefits, particularly in cost savings and environmental stewardship using the natural bi-products derived from it allow us to stay afloat. The answer is that if we are not paid the price to compare we are paid today, we cannot break even. The digester must pay for itself in order for us to break even and that won't happen at a wholesale rate.

Q. If your payment for excess energy (what you put onto the grid) were reduced as PPL has proposed, would the answer be the same?

A. Because it is not clear what the rates would be from hour to hour under PPL's proposal, it is difficult to know. However, we cannot afford to operate the digester – even with the benefits they produce – if they cannot at least break even.

Q. What are the consequences if you can't make the same amount of money operating the digester?

A. If we can't make the same amount, the cost to compare, operating the digester, we cannot continue to operate it reliably into the future. The margin on it is slim as it is, and that is what is used to fund maintenance and provide reserves toward capex for necessary upgrades or large equipment replacement. The consequences of that would completely alter the way we farm and our ability to sustain our family business.

Q. What relief are you and other dairy farmers operating digesters in the PPL service territory seek in this proceeding?

A. We have been operating a digester on our farm since 2006 on the economics of being paid the price to compare for our rate class for the electricity we have consistently and reliably delivered onto the grid – 24 hours per day, 7 days a week, with very little downtime. We eliminate a substantial amount of demand from the grid when the grid is most stressed, which saves money for all customers, and we provide other benefits as well. These benefits, which the General Assembly recognized, were part of the bargain when we invested millions of dollars of our money to make our operations more sustainable, so we could continue to produce the food that is vital for our community, and to improve the environment for our neighbors. What PPL is proposing is to change the deal mid-stream, to our detriment, and to the detriment of its customers. I am advised by counsel that the Alternative Energy Portfolio Standards Act ("AEPS Act") does not authorize utilities such as PPL, or the Commission to modify procurement classes or rate classes in order to reduce the compensation to customer generators to offset the alleged cost of net metering. More important for me is that these changes will impact our ability to continue our excellent stewardship of the land and air that has been in our family for multiple generations. The scope of dairy operations are limited by the ability to manage the manure generated by those operations. Stated differently, without a digester, we may need to reduce the number of cows we milk, which will reduce our output with all the cascading impacts that produces, both for our family, our employees, and for our customers. We ask the Commission to reject PPL's proposed changes to PPL's tariff that will harm customer generators and the environment, with no benefit for ratepayers.

We want the PUC to comply with the AEPS Act, and ensure that we are paid full retail value for our energy and to put an end to the false claims that net metering harms customers – it does not. We are not able to operate in our current sustainable mode without the small customer price to compare and I believe that under the APES Act, we are entitled to it. I also want the Commission to ensure that all elements of default service are compensated, not just the per kwh charges, the current methodology is not right and is an insult to the farmers that feed the people of Pennsylvania.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
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The Coalition for Community Solar Access	:	
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Safiyah Junaid	:	C-2025-3058983
Stacey Kimmel-Smith	:	C-2025-3059151
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

SURREBUTTAL TESTIMONY
OF JAMES HARBACH
ON BEHALF OF THE PROFESSIONAL DAIRY MANAGERS
OF PENNSYLVANIA

PDMP Statement No. 1-SR
February 9, 2026

Q. PLEASE STATE YOUR NAME.

A. My name is James Harbach.

Q. ARE YOU THE SAME JAMES HARBACH THAT SUBMITTED DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. To respond to the Rebuttal Testimony of several other witnesses in this proceeding. I will respond to the Rebuttal Testimony of PPL witnesses Mr. Andrew Castanaro and Mr. Gregory Olsen; Office of Small Business Advocate ("OSBA") witness Mark Ewen and Office of Consumer Advocate ("OCA") witness Zack Teti.

Q. DO YOU HAVE A GENERAL RESPONSE TO THESE WITNESSES?

A. Yes, I find it ironic that the OSBA and OCA have taken the side of making my digester and renewable energy production uneconomic; first because I am a small business; and second, because if fewer dairy farms using anerobic digesters, which will be the result if PPL's plan is approved, means the farms that invested in those technologies will in the immediate future be economically harmed because they will need to employ new means of compliance, which means less milk which ultimately will lead to scarcity an increasing prices for milk and all the products made from milk. This is no idle threat – this is economic reality and they appear to favor supporting the myth that net metering harms customers and must be restrained, over the hard facts that net metering provides economic and

environmental benefits and, as I have been advised by counsel, has never been shown to increase retail prices to customers.

RESPONSE TO PPL WITNESS MR. ANDREW CASTANARO

Q. ON PAGE 4, LINES 4-12 OF MR. CASTANARO'S STATEMENT, HE ADMITS THAT CUSTOMER GENERATORS PROVIDE BENEFITS TO CUSTOMERS ON THE PPL SYSTEM IN THE FORM OF REDUCING CAPACITY COSTS FOR ALL CUSTOMERS ON DEFAULT SERVICE, BUT GOES ON TO CLAIM THAT "THE COMPANY'S PROPOSAL IS NOT ABOUT THE VALUE CUSTOMER-GENERATORS ADD TO THE SYSTEM, BUT RATHER THE APPROPRIATE CLASSIFICATION FOR PROVIDING DEFAULT SERVICE TO THESE CUSTOMERS." HOW DO YOU RESPOND?

A. Mr. Castanaro's contention is misguided. He admits that customer-generators, like Schrack Farms, provide benefits to the PPL system, which he implies are good, but in the same breath wants to reduce our compensation by reclassifying us as a large customer for purposes of default service. PPL wants the benefit but wants to pay us less to obtain it. In my view that is unreasonable and discriminatory and in violation of the APESA which requires that we be paid at full retail value – in part because of the benefits we provide to the system.

Q. ON PAGE 8 OF HIS STATEMENT, MR. CASTANARO CLAIMS THAT 1 MW OF NET METERED GENERATION IS ALWAYS MORE EXPENSIVE THAN 1 MW OF FIXED PRICE FULL REQUIREMENTS ELECTRICITY – HOW DO YOU RESPOND?

A. I have two answers, first, I am advised by counsel that the AEPS Act does not require that net metering produce savings or even not increase rates for customers; even though I believe it does. Second, in his testimony, Mr. Castanaro admits that customer-generators provide benefits by reducing costs to customers. Yet, in his example, he does not recognize those benefits.

RESPONSE TO PPL WITNESS GREGORY OLSEN

Q. HOW DO YOU RESPOND TO THE Q&A IN MR. OLSEN'S TESTIMONY AT PAGE 18, WHERE HE CLAIMS THAT CUSTOMER-GENERATORS SHOULD NOT "MAKE A PROFIT OFF OF THEIR INVESTMENTS?"

A. My first reaction is that perhaps Mr. Olsen should consider that PPL is in the middle of a rate case seeking a 34% rate increase so that it can continue to earn a profit off of its investments in equipment - that ratepayers pay for. Schrack Farms paid for the assets that it uses to try to earn a profit (no profit is guaranteed) on its operations, including the facilities that PPL uses to connect us to the distribution system. The payments Schrack Farms receives from PPL, while significant, only allow the farm to continue to operate the digester, and the profits are variable and sometime very slim. The payment for our excess generation at full retail value was the bargain we struck when we made the substantial

investment in the equipment, and if that is taken away, our profits will dwindle dramatically. Full retail value is what we are owed. It is clear that both Mr. Olsen's and Mr. Castanaro's Testimony admits that PPL's proposal is less than full retail value. They both suggest that PPL is proposing to reduce payments to customer generators to save customers money. Since no one has contended that we are paid more than full retail value, that means PPL is proposing to pay us less than.

Q. HOW DO YOU RESPOND TO MR. OLSEN'S ATTEMPT TO DEFLECT YOUR TESTIMONY REGARDING PPL'S LACK OF RESPONSIVENESS WHEN YOU SOUGHT TO UPGRADE YOUR EQUIPMENT? (PG. 19:9-17)

A. Mr. Olsen can make all of the excuses he wants but at the end of the day it was PPL that caused the vast majority of the delay.

RESPONSE TO OSBA WITNESS MR. EWEN

Q. HOW DO YOU RESPOND TO MR. EWEN'S CONTENTION ON PAGE 2, LINE 3, THAT PPL'S PROPOSAL WILL RESULT IN CUSTOMER-GENERATORS BEING "FAIRLY COMPENSATED?"

A. I disagree with Mr. Ewen's uninformed opinion. Cutting the compensation for customer generators - particularly those that have been in operation for years and that have made substantial investments in infrastructure to allow them to operate at an efficient level – is not fair, is not justified, and is not permitted by the AEPS Act.

RESPONSE TO OCA WITNESS ZACH TETI

Q. WHAT RESPONSE DO YOU HAVE TO MR. TETI'S ADMISSION ON PAGE 3, LINES 11-16, THAT THE GSC 1 IS "PROCUREMENT-BASED", THAT IS OFFSETTING THE FULL RETAIL VALUE OF GENERATION, WHILE THE GSC-2 RATE, AS PROPOSED, IS "MARKET-BASED" WHICH CAN ONLY MEAN THE WHOLESALE MARKET?

A. I agree with Mr. Teti that the current GSC-1 rate is based on what PPL avoids by procurement and that the proposed GSC-2 rate is based on wholesale prices. I note that my understanding, based on advice from counsel, is that GSR-1 is the closest to full retail value and that GSC-2 is an LMP + rate that does not mirror or provide full retail value because it does not reflect all of the costs of providing default service. These are legal arguments that we will address in briefs.

Q. HOW DO YOU REACT TO MR. TETI'S CLAIM ON PAGES 3-4 THAT CUSTOMER-GENERATORS "STRESS" THE PPL DISTRIBUTION SYSTEM?

A. I would first state that neither Mr. Teti nor Mr. Castanaro have offered any evidence to support that allegation. I also posit that such costs would be "distribution costs" if they existed and could be proved. Primarily, however, I don't agree that such alleged "stresses" exist or impose any more strain on PPL's system than providing distribution service because I have paid for the upgrades that PPL said were needed so that my generation would not stress the distribution system.

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Stacey Kimmel-Smith	:	C-2025-3059151
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

DIRECT TESTIMONY
OF TIMOTHY RENSCH
ON BEHALF OF THE PROFESSIONAL DAIRY MANAGERS
OF PENNSYLVANIA

PDMP Statement No. 2
December 22, 2025

Q. Please state your name and business address.

A. My name is Timothy Rensch. The business address is NCS, Inc. 130 Industrial Drive, Chambersburg, PA 17201.

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

A. I am Employed as President and CEO at NCS, Inc. I am also a Partner in Trinity Bio-Energy, LLC.

Q. Describe your work responsibilities?

A. See attached resume for NCS, Inc. For Trinity Bio-Energy responsibilities include project development for waste to energy projects involving primarily anaerobic digestion. I also am responsible for technical design oversight of said projects.

Q. Do you have specialized expertise in the mechanical operation, installation and economics of anerobic digesters for the conversion of animal and food waste on dairy farms? Explain.

A. Yes, substantial. I have personally been involved in the treatment of food waste and manure for the bulk of my professional career spanning 25 years. Work with anaerobic digesters has occurred since 2008 with initial study of the technology in Europe resulting in securing technology rights into the US.

In addition to this, NCS's historical core customer base milks an average of 2,000 cows and approximately 20 of our customers have installed AD since 2008. These direct customer relationships have provided intimate knowledge on the operation, installation and

economics of these facilities. I have been personally involved in all of these aspects on these projects, particularly the operational and installation side.

Since the beginnings of the Renewable Natural Gas (RNG) sector within the dairy space in approximately 2020, I have also been deeply involved in the economic evaluation of an additional 20 AD plant feasibility designs. Some of these projects have been constructed and some did not pass economic review.

Q. Please describe briefly how an anerobic digester works?

A. Anaerobic Digestion is simply the breakdown of organic materials in a non-oxygen environment by anaerobic bacteria (anaerobic = without O2 vs. aerobic = with O2). It is a naturally occurring process that under a specific set of design conditions can be controlled to produce output products. The core of those is biogas which typically contains in excess of 55% methane (pure natural gas) along with a resulting digestate that has agronomic benefits.

Q. Why is this technology, or similar technologies, important to the dairy industry?

A. Due to the realities of our modern world, dairy farms have grown significantly in size over the last half century to present day. This has been driven by the need to economically feed larger global populations. The math is simple – more people need more food and to have more food you need larger, more productive and efficient farms. In addition, while at the same time that farmers have had to produce more, the demands for them to reduce their environmental impact have increased tenfold; they are pressured by government, neighbors, and their dairy customers.

The outgrowth of larger farms is the generation of more dairy manure due to larger farms and larger animals that produce more manure, and the corresponding responsibility to further reduce their environmental impact. With our growth in population and food supply demands there has also been an increase in the production of more processed foods (meats, cheeses, refined dairy products, beverages, etc.). The increase in the production of these processed foods creates Food Processing Residuals (FPRs) which require disposal.

Dairy manure is a natural fertilizer and due to its partial stabilization in the digestive system of the cow, and often combined with FPRs makes an excellent feed stock material to AD.

When done properly these projects on dairy farms can provide a more stable and self-sustaining method to manage manure, particularly if they can capture revenue to the dairy from tipping fees, fertilizer generation, and electrical sales. Dairy farm revenue from only milk sales can be extremely volatile as the farms have no direct control over the pricing of their milk. This instability can cause extreme financial problems for dairy farmers.

Additionally, the significant odor control benefits of AD make farms much better neighbors and allow them to better co-exist in an increasingly developed landscape.

Q. Are you familiar with the economics of digesters?

A. Yes, very.

Q. In Pennsylvania, how many digesters have you consulted for or constructed?

A. Specifically, in PA, I have consulted with 7 different facilities being involved in design and equipment supply. I have been directly involved in the turnkey construction of 1 AD in PA

with an additional 4 presently in design within PA. Numerous other projects have occurred outside the Commonwealth.

Q. What role does net metering play in the use of digesters?

A. Net metering is a critical aspect on the project economics of digesters that generate electricity as an end product from the biogas. In PA, we do not have farms large enough to do RNG projects and for the PA farm community to benefit from AD, the projects need to be electricity based. Net metering is a critical aspect to capture as much of the potential revenue stream as possible, otherwise, over half the gas tends to just be wasted from the gas flare into the atmosphere.

Q. Do you have any clients that currently operate digesters in the PPL service territory?

A. Not currently operating but we have 1 project that is currently fully permitted, financed and ready to begin construction. This would be for a 1 MW facility.

Q. For those digesters, what financial / economic roles did net metering at the small customer price to compare (PTC), play in the viability of those projects?

A. Again, maximizing all revenue is critical to these projects for the farm to be able to afford to install and keep them running. Building an AD is like building both a wastewater treatment plant and a power plant – just at smaller scale. That smaller scale does not mean these are inexpensive projects. They are constructed to a very high standard for safety and reliability. That makes them 7 figure plus projects. Capital at those levels requires off-setting revenue and being paid fairly for the electric output is critical to the viability of the projects. Maintenance alone of the CHP (Combined Heat and Power Unit) is in the range of $.03-.04 per kwh, not including capex. Even a small CHP is hundreds of thousands of

dollars. Having electricity revenue below even a minimum of $.10 per kwh is typically economically unfeasible.

Q. Is it safe to say that without net metering compensation at its present level, those projects would become non-viable? Explain.

A. Correct. Let's say an average AD on an average 500 cow PA dairy farm costs $5MM to construct. After some incentives, the borrowed amount is $4MM which is borrowed against farm real estate. That would equal annual debt service of $400k. A project of this size might expect to see $300k of tipping revenue for FPRs and $250k-300k of electric sales at current net metered rates. If you reduce the electric to half of that without net metering, the project barely covers the debt service.

Q. What benefits do digesters provide to the farm and the surrounding community?

A. Odor control, water quality improvements, increased nutrient uptake and nutrient availability to crops, and additional farm income. In PA where FPRs are such a hot button issue, AD is the solution. Once FPRs go through AD the odor is greatly, greatly reduced. Using AD also takes pressure off of landfill capacity reducing the need to expand landfills (which no one presumably wants). In essence, AD is a key technology to allow farms and surrounding communities to co-exist to the benefit of each entity. They are truly one of the rare win/wins in constructed projects.

Q. Are these benefits in addition to the benefits that the digester customer-generator provides to the local electric distribution system to which it is connected?

A. Yes.

Q. Can you summarize the benefits that the customer-generator function provides to the local electric distribution system?

A. We have become an electrically driven society. Our demand for power is only going to increase. AD is a reliable provider of much needed additional electrical generation capacity to the power grid. The cows never take a break and are providing the base fuel source (manure) continually 24/7, 365 days a year.

Q. Can you approximate the current cost for a dairy farm to install a digester to manage their manure?

A. On the smaller scale where AD is feasible, I would start at 200 cows at $2MM. Ranging that up to a 2,000 cow facility you are closer to $15MM. Most projects in PA are around the 500 cow range at $4-6MM.

Q. Based upon your knowledge and experience, can you confidently explain what will happen to these benefits if the compensation for these projects is converted to a wholesale rate?

A. Basically, already constructed projects will cease to be economically feasible to operate, and those dairies may need to reduce their herd size to stay within environmental compliance on their manure management plans. Projects in planning will not pass economic muster and no new on-farm digesters will be installed. If power companies are allowed to pay the wholesale rate instead of the retail rate, it will unequivocally end the use of AD on farms in the Commonwealth of Pennsylvania.

Q. Ultimately, what are the ramifications of making digesters uneconomic?

A. The ramifications of making digesters uneconomic would include:

- Increased reliance on public funding for construction which is a stark negative for governmental operational budgets at both the federal and state level.
- Loss of a valuable tool for managing manure and FPRs.
- Loss of a solid revenue source that various agricultural operations desperately need. This could have far reaching impacts to overall farm economic stability and the potential loss of the farm itself. This has far reaching impacts as the saying goes "no farms, no food."
- Increased reliance on non-sustainable methods of electrical generation.
- Increased odor emissions from agricultural facilities, which would likely result in an overall reduction of quality of life for surrounding residents.
- Increased negative water quality impacts as more untreated manures and FPRs are land applied. AD digestate vs non-AD treated manure/FPRs has been shown to be significantly more plant available in terms of nutrient uptake. When the crops are up taking the nutrients as intended, they are not running off into our public waterways and drinking water sources where they can cause substantial environmental degradation and overall negative public health impacts.
- Farms would lose the economic upside of naturally produced biproducts the digester affords them which will ultimately increase their cost of production and likely result in either increased consumer food costs or forcing the family farms to fold, perhaps both.

EXHIBIT TR-1

Timothy Rensch

President/CEO **Partner**
Nutrient Control Systems, Inc. **Trinity BioEnergy, LLC**

Experience Summary

Over 25 (twenty-five) years experience in the planning, design, permitting, and operations of wastewater treatment facilities with particular emphasis on waste streams resulting from production animal agriculture. Mr. Rensch served as the lead technical member of the senior management team that developed the technologies utilized by NCS's various diversified divisions.

Mr. Rensch was a partner in the acquisition of key nutrient management technologies and co-founded Nutrient Control Systems, Inc.

In 2014 Mr. Rensch helped lead the restructuring of NCS, Inc. to both recapitalize the business and to direct the focus into products derived from agricultural residuals.

In 2022 Mr. Rensch led NCS's acquisition of an equity ownership position of a retail level consumer soils products brand.

In the current position of President/CEO, Mr. Rensch reports directly to the company board of directors with responsibility for overall business strategy, engineering, finance, and corporate direction.

Mr. Rensch also is a Partner and Founding Member of Trinity BioEnergy, LLC. Trinty is a specialist construction company that builds waste to energy anaerobic digestion facilities.

Credentials

Post Graduate work in Nutrient Management Planning – The Pennsylvania State University.

M.S. Geo-Environmental Science, Shippensburg University. 1998. First in class.

B.S. Geo-Environmental Science, Magna Cum Laude, Shippensburg University. 1997.

B.A. History/Political Science, Magna Cum Laude, Shippensburg University. 1997.

American Society of Agricultural Engineers

Key Projects

Developed the technology and financial models for the creation of a peat-like substance derived from agricultural residuals. This product has been adopted by multi-national horticultural companies, and is used in various industrial applications.

Senior Project Director in the design, construction, and operation of 50-plus full scale waste treatment facilities for Concentrated Animal Feeding Operations (CAFOs). These projects have involved the use of innovative treatment concepts which have served to mitigate the water quality, air quality, and other potential environmental impacts of large scale animal agriculture production facilities. This work has encompassed multiple geographic sectors along with multiple herd sizes ranging up to 10,000 animals.

Timothy Rensch

President/CEO
Nutrient Control Systems, Inc.

Partner
Trinity BioEnergy, LLC

Senior Project Director in the investigation and technical due diligence of approximately 30 anaerobic digestion technologies for utilization in industrial/agricultural waste treatment. This project involved multiple process evaluations to determine suitability of technologies for the anaerobic decomposition of waste materials and associated energy production opportunities. The results of this work were negotiating and securing the sales rights to multiple appropriate technologies.

Expert Witness testimony for multiple cases involving the expansion of CAFOs and explanation of methodologies to mitigate potential environmental impacts. Testimony was provided both on behalf of the client company and under cross-examination. The efforts resulted in securing the permits necessary for project construction.

Senior Project Director in the development of an advanced dewatering approach for the purpose of converting dairy manure into a renewable solid fuel. Work has included direction of the efforts of technology development and field performance evaluations.

Senior Project Director in the development of multiple innovative technologies for the treatment and land application of agricultural/industrial waste streams. This work has encompassed the development of both process and equipment based solutions. Direct technical oversight was provided for process and equipment testing, design/engineering drawings for equipment production, and marketing/sales strategy. This resulted in the development of multiple equipment items/processes including a roller press dewatering machine, tapered screw press, advanced chemical treatment systems for phosphorous removal, and controlled rate land application technology. Patent rights were secured for the appropriate technologies (of which Mr. Rensch is a co-patent holder), and all equipment was ultimately put in production and continues to be sold into and operated at multiple agricultural and industrial facilities.

Senior Project Director for a federally funded project as part of the United States Congress' Farm Pilot Project Coordination Program. This project involved the testing and implementation of multiple on farm nutrient removal strategies for the purpose of mitigating the impacts of concentrated animal agriculture within the Chesapeake Bay Watershed. Particular attention was devoted to the innovative use of polymer and coagulant based chemistry for the purpose of fine particulate removal. The project ultimately resulted in a successful technology demonstration.

Technical Advisor between a private technology development company and the Virginia Polytechnic Institute (VA Tech) for a multi-year, peer reviewed study of wastewater treatment processes and their application to manure effluents. Work involved serving as the key technical advisor for issues involving sampling protocol, quantitative laboratory analytical evaluations, and data review for academic defense. This work resulted in multiple journal articles and professional presentations.

Positions

President/CEO. Nutrient Control Systems, Inc., 2015-Present.

President. Nutrient Control Systems, Inc., 2008-2014.

Board of Directors. Nutrient Control Systems, Inc., 2001-Present.

Timothy Rensch

President/CEO **Partner**
Nutrient Control Systems, Inc. **Trinity BioEnergy, LLC**

Director of Sales/Engineering. Integrity Ag Systems, 2004-2008.

Technology Director. Integrity Ag Systems, 2001-2004.

Technical Director. Falling Spring Environmental Services, 1999-2001.

Field Scientist. Environmental Operations Consultants (ENOPCON), 1998-1999.

Research Assistant. Shippensburg University, 1997-1998.

Timothy Rensch
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	
Energy Efficiency in Pennsylvania	:	C-2025-3057844
Office of Small Business Advocate	:	C-2025-3057889
Office of Consumer Advocate	:	C-2025-3058130
Brad and Jennifer Wooley	:	C-2025-3057946
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Solar Energy Industries Association and	:	C-2025-3058251
The Coalition for Community Solar Access	:	
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058983
Stacey Kimmel-Smith	:	C-2025-3059151
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

SURREBUTTAL TESTIMONY
OF TIMOTHY RENSCH
ON BEHALF OF THE PROFESSIONAL DAIRY MANAGERS
OF PENNSYLVANIA

PDMP Statement No. 2-SR
February 9, 2026

Q. WHAT IS YOUR NAME?

A. My name is Timothy Rensch.

Q. ARE YOU THE SAME TIMOTHY RENSCH THAT PROVIDED DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. To respond to PPL witness Castanaro's contentions about net metering and anerobic digesters in particular.

RESPONSE TO PPL WITNESS ANDREW CASTANARO

Q. WHAT DOES MR. CASTANARO SAY ABOUT YOUR TESTIMONY THAT WARRANTS A RESPONSE?

A. At page 41 of his Rebuttal, Mr. Castanaro responds to my testimony that PPL's change in rate will make anerobic digesters un-economic? He claims that the broader policy implications of digesters becoming uneconomic is beyond the scope of this proceeding and admits that the while the concerns I raise are legitimate, this case is about PPL gaining a "fair" rate design.

Q. DO YOU HAVE ANY RESPONSE TO MR. CASTANARO'S STATEMENTS?

A. Yes. This case is about designing rates for PPL, but PPL has injected into this case the issue of the fairness of the present default service rate structure. They cannot ring the doorbell and run. The AEPS Act made many policy choices and among them were the technologies that were authorized to participate in net metering, and that net metering customer-generators of all sizes must be paid full retail value. One of the authorized technologies was and continues to be electricity generated by consuming methane gas produced from anerobic digesters, for all of the reasons they benefit Pennsylvania. For Mr. Castanaro to claim that the current compensation is not fair, even though it is what was mandated by the AEPS Act, is an attack on the very policy choice the General Assembly made and is clearly part of this proceeding. PPL's choice to ignore the law and propose a compensation scheme that produces less than the law requires is a choice PPL made and they cannot simply brush it off on policy makers as being their problem. The General Assembly passed a statute that requires PPL to pay full retail value, and PPL is proposing to pay less. Mr. Castanaro's saying "not my problem" is wrong. PPL created the problem by defying what the law requires.

Q. DO YOU HAVE ANYTHING ELSE TO ADD?

A. Not at this time.