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 and Request for the Approval of Affiliated Interest Agreement Of UGI Utilities, Inc - Electric Division Call-In Telephonic Evidentiary Hearing	Docket Nos.: P-2024-3049343 G-2024-3049351

Pages 20 - 133

Judge's Chambers

Commonwealth Keystone

Building - Plaza Level

400 North Street

Harrisburg, PA

Tuesday, October 1, 2024

Commencing at 10:04 a.m.

INDEX TO EXHIBITS

Docket Nos. P-2024-3049343/G-2024-3049351

Hearing Date: October 1, 2024

NUMBER	FOR IDENTIFICATION	IN EVIDENCE
UGI Electric Exhibit:		
Statement 1	31	34
Tyahla Direct Testimony with Exhibits		
Statement 1-R	32	34

Tyahla Rebuttal Testimony with Exhibit		
Statement 2	37	72
Faryniarz Direct Testimony with Exhibits		
Statement 2-R	38	72
Faryniarz Rebuttal Testimony with Exhibits,		
Public and **Confidential**		
Statement 2-RJ	39	72
Faryniarz Rejoinder Testimony with Exhibits		
Exhibit 1	74	78
Petition		
Statement 3	75	78
Hazenstab Direct Testimony with Exhibits		
Statement 3-R	76	78
Hazenstab Rebuttal Testimony with Exhibits		
Statement 3-RJ	77	78
Hazenstab Rejoinder Testimony with Exhibits		
Penn Renewables Exhibit:		
Statement 1	97	99
Crist Direct Testimony with Exhibits		
Statement 1-SR	97	99

Crist Surrebuttal Testimony with Exhibits

Office of Consumer Advocate Exhibit:

Statement 1	118	120

Ogur Direct Testimony

Statement 1-R	118	120

Ogur Rebuttal Testimony

Office of Consumer Advocate Exhibit:

Statement 1-SR	119	120

Ogur Surrebuttal Testimony

Public and **Confidential**

Statement 1	121	122

Ewen Direct Testimony with Exhibit

Statement 1-R	121	122

Ewen Rebuttal Testimony

Statement 1-S	121	122

Ewen Surrebuttal Testimony

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. –	:	
Electric Division For Approval of	:	Docket Nos. P-2024-
a Default Service Plan (DSP V) for	:	G-2024-
the Period of June 1, 2025 through	:	
May 31, 2029	:	

DIRECT TESTIMONY
OF
JESSE R. TYAHLA

UGI ELECTRIC STATEMENT NO. 1

Dated: May 31, 2024

I. Introduction

Q. Please state your name and address.

A. My name is Jesse R. Tyahla. My business address is UGI Utilities, Inc., 1 UGI Drive, Denver, PA 17517.

Q. By whom are you employed, and in what capacity?

A. I am employed by UGI Utilities Inc. ("UGI") as Director – Energy Supply and Planning. UGI is a wholly owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please briefly describe your responsibilities in your current capacity.

A. As Director – Energy Supply and Planning, I am responsible for natural gas and electric supply planning, procurement, and scheduling for UGI Electric and UGI Gas. Additionally, I am responsible for the development and administration of delivery requirements for licensed electric gas suppliers ("EGSs") who serve Choice Customers that elect to procure supply services from EGSs on UGI Electric's system. Furthermore, I am responsible for overseeing the implementation of UGI Electric's Default Service Plan ("DSP").

Q. What is your educational background?

A. Please see my resume that is attached as UGI Electric Exhibit JRT-1.

Q. Have you previously testified as a witness before the Commission?

A. Yes, please see UGI Electric Exhibit JRT-1 for a listing of the proceedings in which I have been a witness on behalf of UGI Utilities.

Q. What topics will you address in your direct testimony?

A. The purpose of my testimony is to: (1) describe the Company's current DSP period; (2) detail the Company's activities undertaken in compliance with its prior settlement obligations; (3) describe the Company's proposed DSP V period; and (4) describe the Company's plan to seek an auction manager for its proposed DSP V period.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the exhibits identified as UGI Electric Exhibits JRT-1 and JRT-2.

II. CURRENT PLAN – DSP IV

Q. What is the effective period for the Company's DSP IV?

A. On June 1, 2020, UGI Electric filed its *Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP IV) for the Period of June 1, 2021 through May 31, 2025* at Docket Nos. P-2020-3019907 and G-2020-3019908 ("DSP IV"). The Commission approved UGI Electric's DSP IV as modified by settlement in its Order entered on January 14, 2021. DSP IV spans the four-year period from June 1, 2021 through May 31, 2025.

III. SETTLEMENT COMMITMENTS FROM THE DSP IV PROCEEDING

Q. Were there any commitments made by UGI Electric in the settlement of DSP IV that the Company was required to act on after the case concluded?

A. Yes. The Company committed to undertake a procurement study using a third-party consultant, and to file the results of that study before June 30, 2022. The study was intended to explore the relative cost of default service supply to residential and non-residential customers, to address whether to: (1) continue its existing combined procurement methodology for residential and non-residential customers under the single GSR-1 rate; (2) propose separate procurements for residential and non-residential GSR-1 customers including separate GSR-1 rates for each respective customer class; or (3) maintain combined procurements with differentiated rates for residential and non-residential GSR-1 customers.

Q. Did the Company undertake the required study?

A. Yes. The Company hired NorthBridge Group to perform the procurement study. In undertaking its evaluation, NorthBridge Group reviewed data from DSP III and DSP IV through the Fall of 2021. The study identified the individual cost components associated with default service supply for UGI Electric's residential and non-residential GSR-1 customers under both block-and-spot and fixed-price, full requirements ("FPFR") product procurement methods. The cost components reviewed included Energy, Capacity, Network Integration Transmission Service, and Other Costs. The Company filed the study on June 29, 2022, consistent with its commitment in the settlement of DSP IV. A copy of

that filing is attached to my testimony as JRT-2. As described in the filing, the Company proposed that it would not implement the conclusions of the study until DSP V.

Q. What did the study conclude?

A. The study determined that the relative costs, measured in dollars per megawatt hour, would likely be 2% higher for residential GSR-1 customers, and 6% to 7% lower for non-residential GSR-1 customers over the three-year period remaining in DSP IV. The study also determined that separate procurements would increase cost-related risks and increase administrative costs. Instead, the study recommended that a rate allocation methodology would better align costs to relative customer groups. The implementation of the rate allocation methodology is described in the testimony of UGI Electric witness Tracy A. Hazenstab, UGI Electric Statement No. 3.

Q. Did the Company make any other commitments in its DSP IV settlement?

A. Yes. The Company agreed in the settlement to adjust its practices as related to reverse migration. As discussed in Ms. Hazenstab's testimony, the Company complied with the terms of the settlement.

IV. PROPOSED PLAN – DSP V

Q. What is the proposed period for the Company's upcoming DSP V?

A. In this proceeding, the Company seeks to implement its DSP V plan during the four-year period from June 1, 2025 through May 31, 2029. The Commission's Default Electric Service ("DES") Policy Statement, at 52 Pa. Code § 69.1804, encourages the use of a DSP

term of two to three years, unless otherwise approved by the Commission. The Commission approved a four-year term for the Company's DSP III and DSP IV plans, the latter of which is scheduled to end on May 31, 2025. This extended term, as compared to earlier Default Service Plans, has improved the efficiency of the plan by decreasing the time and expense associated with regulatory proceedings. In addition, the Commission has approved four-year default service plans for other default service suppliers, including PPL Electric Utilities Corporation, Duquesne Light Company, the First Energy Companies, and PECO Energy Company. UGI Electric seeks the same allowance to implement its DSP V over a four-year term.

Q. Please describe the Company's approach and overall goals for DSP V.

A. The Company proposes to maintain two customer groupings: GSR-1 (customers below 100kW of supply peak load impact) and GSR-2 (customers at or above 100kW of supply peak load impact) and to continue to utilize full requirement and block products used in DSP IV, albeit with an eye toward increasing solicitation participation, lowering risk premiums, and improving stability between rate changes. Please see the testimony of Ms. Hazenstab, UGI Electric Statement No. 3, for a more detailed discussion related to GSR-1 and GSR-2, and the testimony of UGI Electric witness James M. Rouland, UGI Electric Statement No. 2, for a more detailed discussion of the Company's procurement plans. In addition, and as discussed in the testimony of Mr. Rouland, the Company proposes to implement a robust contingency plan that would operate in the event of a supplier default or failed solicitation, as well as additional collateral requirements to provide greater

customer protections. Finally, by maintaining a four-year term, the Company will experience lower administrative and legal expenses, resulting in cost savings for customers.

Q. Is the Company proposing any changes as part of DSP V in this proceeding?

A. Yes. The Company is proposing changes to its procurement activities, portfolio structure, and rates, as discussed in greater detail in the testimony of UGI Electric witnesses Mr. Rouland and Ms. Hazenstab.

Q. In addition to the proposed changes to the plan itself, did the Company adopt any other modifications to its planning process as part of DSP V?

A. Yes. In advance of its filing and in support of its procurement process, UGI Electric obtained a consultant, Daymark Energy Advisors, Inc., to conduct a thorough evaluation of its DSP performance to date and to make recommendations for procurement practices that are appropriate for UGI Electric's size and load profile. UGI Electric has not had a comprehensive evaluation of its portfolio and performance conducted by an independent third party since the implementation of its DSP in 2008, and the market has evolved significantly since that time. The evaluation included, among other factors, a review of the Company's auction results and ensuing costs to date, customer rate group usage patterns, options for risk management, portfolio structures of other Pennsylvania EDCs, portfolio composition of similarly situated entities, etc. Mr. Rouland's testimony provides a discussion of the review process and makes recommendations based on that evaluation. The costs associated with Daymark's review and evaluation are included in the

administrative costs reflected in DSP V and amortized over the four-year life of the plan, as described by UGI Electric witness Ms. Hazenstab, UGI Electric Statement No. 3.

V. AUCTION MANAGER REQUEST FOR PROPOSAL

Q. Please describe UGI Electric's current use of a market monitor.

A. In the last two DSP periods, UGI Electric used an independent market monitor that also administered the Company's default service bidding process. This entity was responsible for conducting the RFPs, including advertising notice in industry publications, participating in conference calls with suppliers, as well as preparing a report on market conditions that was submitted to the Commission with the auction results. The market monitor also oversaw the RFP process, including reviewing and evaluating bids with the Company, and submitting the results to the Commission.

Q. Is UGI Electric proposing any modifications to its use of a market monitor in DSP V?

A. Yes. UGI Electric believes that the market monitor role should be reconfigured for DSP V such that it becomes a broader auction manager role. The auction manager role would subsume the market monitor role. Specifically, UGI Electric plans to issue an RFP to secure an entity that will assist the Company to: drive increased supplier participation that will result in a more competitive auction process; enhance collaboration and attention to suppliers to improve the overall energy auction experience and likely improve future participation; improve the quality of data collection, reporting, and communication with key stakeholders; and provide greater support to UGI Electric, participating bidders, and Commission evaluators throughout the process.

Q. What additional services is the auction manager going to provide?

A. UGI Electric's RFP will seek comprehensive support for the pre-auction, pre-bid day, bid-day, and post-auction periods. Pre-auction activities are those that prepare for or support an impending solicitation window and typically occur over the weeks prior to the opening of a solicitation. The auction manager will conduct proactive supplier outreach and notification of the auction, preparing template forms and other documentation for posting on the website, review and propose recommendations to improve the clarity of communications on the website, and review data to be posted for prospective suppliers.

The pre-bid day period encompasses the auction kickoff until the bid-day. Some of the primary activities that the Company expects to have supported during this period include formal communications to suppliers and other external stakeholders, conducting a bidder information session, ongoing supplier management and qualification, bid collateral review, supplier bid training, answering supplier questions and updating of posted FAQs, and ongoing communication and trouble shooting in conjunction with the UGI team.

On bid-day, UGI Electric will require support maintaining communication with suppliers, evaluating bids quickly and precisely, communicating bid results to stakeholders, and developing an Auction Results Report to be submitted to the Commission to support their review and approval process.

Finally, UGI Electric is seeking comprehensive post-auction support. This includes facilitating communication between UGI Electric and suppliers – execution of transaction confirmations, return of bid collateral, transfer of performance assurance, and answering of final auction-related questions. The auction manager will be responsible for ensuring that all

necessary documentation is complete and will transfer data and documents associated with the entire auction process to UGI Electric for its records. Once all post-bid day contract management activities are complete, the auction manager will be expected to conduct supplier outreach to solicit feedback on the entire auction process – successes, concerns, and other related opportunities for improvement (or maintenance), and provide UGI Electric with post-auction analysis that includes any recommended updates or alterations to improve the quality of future auctions.

Q. How will the auction manager improve the reporting functions provided by the market monitor?

A. UGI Electric's RFP will seek improved reporting and communication that expands the current reporting undertaken by its market monitor. The auction manager will be responsible for submitting two key reports to the Commission: the State of the Market Report and the Auction Results Report. The State of the Market Report is intended to provide information on the state of the Pennsylvania and PJM market, including market developments or issues, forward prices (energy, capacity, and AECs), as well as insight or indication of the range of wholesale and AEC prices likely for the products being auctioned based upon the best-known information. The auction manager will be expected to provide comprehensive reports with clear sourcing and citations, based on a consistent methodology, with the expectation that the auction manager will present the report to the Company in advance of the auction and discuss any noteworthy findings that may impact the auction. The auction manager will also be responsive to feedback, questions and concerns raised by Commission Staff relating to the State of the Market Report.

The Auction Results Report is the formal report issued to the Commission immediately following an auction, providing the complete details supporting the auction results, and enabling the Commission to issue a Secretarial Letter approving the results. The Company expects that timely analysis, thorough documentation, and clear and concise conclusions will be delivered to the Commission. The Company expects its auction manager to respond quickly to concerns or questions raised by Commission Staff, as auctions must be reviewed and approved on a shortened timeline.

Q. What is the anticipated cost of the auction manager service?

A. The cost of this service is anticipated to be approximately $150,000 for the first year of DSP V, with lower costs expected in years 2 through 4. The Company anticipates higher costs in the first year due to the need to evaluate and improve existing materials, tools and processes, as well as efforts focused on developing a larger pool of participating suppliers. The impact of the cost of the auction manager on rates is presented in Ms. Hazenstab's testimony, UGI Electric Statement No. 3.

Q. Does this conclude your testimony?

A. Yes.

UGI Electric
Exhibit JRT-1

Jesse R. Tyahla

1 UGI Drive, Denver, PA 17517
Phone: (610) 781-1993
Email: jtyahla@ugi.com

Experience

Oct. 2020 – Present **UGI Utilities, Inc.** **Denver, PA**

Director – Energy Supply & Planning

- Directed teams and individuals in managing the natural gas and electric supplies for UGI Utilities
- Drafted testimony and exhibits in FERC proceedings impacting UGI Gas rate payers
- Coordinated cross-departmentally to develop supply procurement strategies for reinforcement and growth

Oct. 2018 – Oct. 2020 **UGI Energy Services, LLC** **Wyomissing, PA**

Director – Supply Origination & Business Development

- Directed retail and wholesale business opportunities ranging from acquisitions, marketing assets, valuation dynamics and strategic initiatives
- Evaluated markets concurrent with UGIES' retail, wholesale, midstream, and fixed asset positions
- Oversaw the acquisition of locally sourced supplies for strategic markets; reported monthly performance
- Contributor to risk management strategy

Oct. 2014 – Sept. 2018 **UGI Energy Services, LLC** **Wyomissing, PA**

Manager – Gas Supply Trading

- Planned, developed, and maintained a trade team of five physical gas traders
- Solicited, summarized, and recommended economic frameworks and execution strategies to senior management in relation to long-term supply and demand positions
- Developed, reviewed, and provided feedback on Request for Proposals (RFPs), Asset Management Agreements (AMAs), and contract Open Season opportunities with other natural gas marketers, local production companies and interstate pipelines

Jul. 2012 – Oct. 2014 **UGI Energy Services, LLC** **Wyomissing, PA**

Analyst – Supply and Asset Optimization

- Monitored and scheduled over 30 natural gas storage facilities and inventory positions
- Conducted and reported valuation of AMA, RFP, and Open Seasons for Natural Gas supply and assets
- Executed daily position and valuation reporting to include the profit and loss statement for the Gas Supply department

Jul. 2010 – Jun. 2012 **UGI Utilities, Inc.** **Reading, PA**

Supply Analyst

- Responsible for purchases, sales, and exchanges of natural gas physical commodities
- Scheduled natural gas supplies from producers to local distribution companies on interstate pipelines
- Created tools which improved the efficiency and accuracy of daily and monthly scheduling activities for all schedulers

May 2008 – Jun. 2010 **UGI Utilities, Inc.** **Reading, PA**

Rates Analyst

- Reviewed customer segments and allocations of annual volumes in support of Base Rate proceedings
- Established quarterly tariff rates based on costs, volume demand projections, and historical revenues
- Updated UGI billing systems with UGI rate changes or choice supplier rates
- Implemented processes improvement strategies for tariff changes with IT and customer billing

Education

M.B.A. (2015) **Lehigh University** **Bethlehem, PA**

- Concentration: Finance
- Cum. GPA: 3.78

B.S. (2008) **Pennsylvania State University** **State College, PA**

- Major: Economics
- Cum. GPA: 3.69

UGI Electric
Exhibit JRT-2

Michael S. Swerling, Esq.

UGI Corporation
460 North Gulph Road
King of Prussia, PA 19406

Post Office Box 858
Valley Forge, PA 19482-0858

(610) 992-3763 Telephone (direct)
(610) 992-3258 Facsimile

June 29, 2022

VIA ELECTRONIC FILING
Rosemary Chiavetta
Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021 through May 31, 2025; Docket Nos. P-2020-3019907 and G-2020-3019908

Dear Secretary Chiavetta:

Attached please find for filing a Procurement Study, titled *Study of the Relative Cost of Default Service Supply for Residential and Non-Residential GSR-1 Customers* dated June 24, 2022, which UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") prepared in accordance with a requirement set forth in an Order of the Pennsylvania Public Utility Commission (Order entered January 14, 2021) in the above-referenced dockets. The Company hired the NorthBridge Group to perform the Procurement Study for UGI Electric, enclosed herewith as Attachment A. Due to its voluminous nature, the Procurement Study's supporting work papers and assumptions will be made accessible to the parties on the certificate of service by way of electronic mail containing a SharePoint site link to the documentation.

I. BACKGROUND

On May 26, 2020, UGI Electric filed its *Petition of UGI Utilities, Inc., - Electric Division for Approval of a Default Service Plan (DSP IV) for the Period of June 1, 2021 through May 31, 2025* at Docket Nos. P-2020-3019907 and G-2020-3019908 ("DSP IV Petition"). On October 23, 2020, the parties filed a Joint Petition for Settlement ("Settlement"), which, in part, stated that the Company would conduct a Procurement Study comparing the relative cost of default service supplies for GSR-1 residential and non-residential customers. Settlement at 7. The Procurement Study would be filed before June 30, 2022 with all workpapers and assumptions. Id.

The study would review data from DSP III and DSP IV through at least the Fall of 2021. Id. Finally, the study would "evaluate the relative costs to GSR-1 residential and non-residential customers associated with: (1) both block-and-spot and full requirements procurements methods; and (2) both separate procurements and cost allocations being made to the residential and non-residential customer

groups under a combined procurement." Id. at 7-8. Concurrent with the Procurement Study, the Company would recommend "whether to: (1) continue its existing combined procurement methodology for residential and non-residential customers under the single GSR-1 rate; (2) propose separate procurements for residential and non-residential GSR-1 customers; or (3) maintain combined procurements with differentiated rates for residential and non-residential GSR-1 customers." Id. at 8.

II. GSR-1 PROCUREMENT COSTS BY CUSTOMER GROUP

The Procurement Study identified the individual cost components associated with default service supply for UGI Electric's residential and non-residential GSR-1 customers under both block-and-spot and fixed-price, full requirements ("FPFR") product procurement methods. The cost components reviewed include Energy, Capacity, Network Integration Transmission Service ("NITS"), and Other Costs. Procurement Study at 3-13. With this data, the Study developed a relative comparison of the total costs to procure supply needed to serve the GSR-1 load for residential and commercial customers between June 2022 and May 2025. The costs (measured in dollars-per-megawatt-hour) of UGI Electric's residential and non-residential GSR-1 default service supply were approximately 2% higher and 6%-7% lower, respectively over the three year period, as compared to the composite GSR-1 default service supply cost. Id.

III. RECOMMENDATION

As the Study finds, separate procurements would likely entail unnecessary cost-related risks (e.g., lack of competitive bid responses), and an estimated $25,000 annual increase in administrative costs. Therefore, the Company's recommendation aligns with a rate allocation methodology posed in the Study. Specifically, to more appropriately assign the expected procurement costs to the relative customer groups, Relative Cost Factors could be developed (similar to the tables on page 14 of the Study) for DSP V and applied to the Energy Cost ("EC") value in the GSR-1 Rate. Page 19 of the Study prepared examples, spanning the period of June 2022-May 2025, showing how to calculate the Relevant Cost Factors. It estimated Relevant Cost Factors of 1.02 for Residential GSR-1 customers and between 0.93 – 0.94 for Non-Residential GSR-1 customers (during that period). The Company intends to propose implementing Relevant Cost factors in its DSP V filing.

Sincerely,

/s/ Michael S. Swerling
Michael S. Swerling

Enclosures: Supporting Information
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that I have, this 29th day of June, 2022, served a true and correct copy of the foregoing document upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

VIA E-FILE & ELECTRONIC MAIL

E-FILE:

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 171020

ELECTRONIC MAIL:

David T. Evrard
Aron J. Beatty
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923
DEvrard@paoca.org
ABeatty@paoca.org

Steven C. Gray
Office of Small Business Advocate
555 Walnut Street
Forum Place, 1st Floor
Harrisburg, PA 17101-1923
sgray@pa.gov

Robert D. Knecht
Industrial Economics, Incorporated
2067 Massachusetts Avenue
Cambridge, MA 02140
rdk@indecon.com

Dr. Serhan Ogur
Exeter Associates, Inc.
Suite 300
10480 Little Patuxent Parkway
Columbia, MD 21044
sogur@exeterassociates.com

Anthony D. Kanagy (ID # 85522)
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101-1601
Tel: 717-731-6034
akanagy@postschell.com

Date: June 29, 2022

/s/ Michael S. Swerling
Michael S. Swerling

Attachment A

Study of the Relative Cost of Default Service Supply for Residential and Non-Residential GSR-1 Customers

Prepared for UGI Utilities, Inc.

Scott G. Fisher
David C. Coleman
The NorthBridge Group

June 24, 2022

THE NORTHBRIDGE GROUP
ECONOMIC & STRATEGIC CONSULTING

Table of Contents

I. Executive Summary 1
II. Default Service Supply Relative Cost Analysis 2
A. Overview 2
B. Energy Cost Estimation 5
C. Capacity Cost Estimation 8
D. Network Integration Transmission Service Cost Estimation 9
E. "Other Costs" Estimation 10
F. Development of Relative Costs by Customer Group 13
III. Evaluation of Combined Versus Separate Procurements 15
IV. Possible Cost Allocation Approach to Reflect Relative Cost Differences in Rates 18
V. Appendix 21

I. Executive Summary

In an Order entered January 14, 2021,[1] the Pennsylvania Public Utility Commission ("Commission") approved and adopted without modification the rates, terms and conditions of service contained in the Joint Petition for Settlement of UGI Utilities, Inc. – Electric Division ("UGI") in the proceedings pertaining to UGI's fourth default service plan ("DSP IV").[2] As a part of the DSP IV Settlement, UGI agreed to file a study:

> *Before June 30, 2022, the Company will file a study of the relative cost of default service supplies for GSR-1 residential and non-residential customers. The Company may select a consultant of its choosing to perform the study. The filing will include all workpapers and assumptions used in the analysis, subject to reasonable confidentiality restrictions as necessary. The study will rely on data from DSP III, DSP IV and actual data through at least the Fall of 2021. The study will evaluate the relative costs to GSR-1 residential and non-residential customers associated with: (1) both block-and-spot and full requirements procurements methods; and (2) both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement.*[3]

This document constitutes that study. Specifically, in fulfillment of the charge of the DSP IV Order, this study:

- Identifies the cost components associated with default service supply for UGI's residential and non-residential GSR-1 customers under both block-and-spot and fixed-price, full requirements ("FPFR") product procurement methods and presents an analysis of the relative cost for each of these two customer groups.
- Presents information and draws conclusions regarding the relative merits of combined versus separate default service supply procurements/products for UGI's residential and non-residential GSR-1 customers.
- Outlines a cost allocation approach that could be applied to translate the cost on a dollars per megawatt-hour basis for combined supply for UGI's residential and non-residential GSR-1 customers into rates that reflect the relative costs for each of these two customer groups.

The main conclusions of our study are as follows:

- Default Service Supply Relative Cost Analysis: Our analysis indicates the costs (measured in dollars-per-megawatt-hour) of UGI's residential and non-residential GSR-1 default service supply are about 2% higher and 6%-7% lower, respectively, as compared to the composite GSR-1 default service supply cost:

[1] Order, *Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021 through May 31, 2025*, Docket Nos. P-2020-3019907, G-2020-3019908, Order entered January 14, 2021. ("DSP IV Order")

[2] Joint Petition for Settlement, *Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021 through May 31, 2025*, Docket Nos. P-2020-3019907, G-2020-3019908, October 23, 2020. ("DSP IV Settlement")

[3] DSP IV Settlement, pp. 7-8.

	Residential vs. Composite GSR-1	Non-Residential GSR-1 vs. Composite GSR-1	Residential vs. Non-Residential GSR-1
June 2022 – May 2023	+2%	-6%	+8%
June 2023 – May 2024	+2%	-6%	+8%
June 2024 – May 2025	+2%	-7%	+9%

- Evaluation of Combined versus Separate Procurements: There is insufficient data to quantify, with a useful confidence level, the expected overall difference in supply cost between an approach in which the default service supply for UGI's GSR-1 group is procured through separate products for residential supply and non-residential GSR-1 supply versus an approach in which the default service supply is procured for the combined GSR-1 group. However, empirical evidence and analysis indicate that splitting the GSR-1 customer group into separate residential and non-residential groups for supply procurement purposes would entail unnecessary cost-related risks.

- Possible Cost Allocation Approach to Reflect Relative Cost Differences in Rates: If the Commission desires to set residential and non-residential GSR-1 default service supply rates in a way that reflects these customer groups' expected relative costs, a reasonable approach would entail applying factors to the combined default service supply cost on a dollars per megawatt-hour basis. For illustrative purposes, consistent with the findings of this study, the factors would be as follows:
    - For June 2022 through May 2023, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.94 would be applied to calculate the non-residential GSR-1 default service supply rates.
    - For June 2023 through May 2024, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.94 would be applied to calculate the non-residential GSR-1 default service supply rates.
    - For June 2024 through May 2025, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.93 would be applied to calculate the non-residential GSR-1 default service supply rates.

  If this cost allocation approach were adopted, factors could be established for a multi-year period, or they could be updated on an annual basis or on another reasonable basis to reflect changes in market conditions, including changes in residential and non-residential shares of the GSR-1 default service load and changes in forward energy or capacity prices. The existing reconciliation mechanism across the GSR-1 customer group would continue to be utilized to ensure that all default service supply costs are recovered.

II. Default Service Supply Relative Cost Analysis

A. Overview

This section identifies the cost components associated with default service supply for UGI's

residential and non-residential GSR-1 customers under both block-and-spot and fixed-price, full requirements ("FPFR") product procurement methods, and it presents an analysis of the relative cost for each of these two customer groups.

Regardless of whether default service supply is procured through a block-and-spot approach,[4] a FPFR product approach,[5] or a hybrid of the two, the supply itself consists of the same basic components. As a result, an evaluation of the relative supply cost for two different customer groups is dependent upon the costs of these components. These components consist of the following:

- Energy – Energy refers to the three-phase, 60-cycle alternating current electric energy, expressed in units of megawatt-hours. PJM operates wholesale markets for energy within its geographic footprint, which includes the UGI service area. Hourly energy prices ("Locational Marginal Price" or "LMP") result from these markets. UGI's default service supply contracts include energy, so it is reasonable to conclude that default service suppliers' bid prices are based on the suppliers' expectations about future wholesale energy prices.
- Capacity – Capacity refers to the commitment of resources to deliver electricity or limit electricity demand when they are needed. PJM operates a wholesale capacity market to ensure resource adequacy within its geographic footprint. Load Serving Entities ("LSEs") in PJM are assessed capacity charges each day based on the prevailing $/MW-day capacity price, which is reset on June 1 of each year, and the LSE's allocation of the overall capacity needed to ensure that annual peak system demands are met. As an LSE, UGI directly incurs capacity costs from PJM for the portion of its default service supply that is not provided by a FPFR product supplier. UGI's FPFR default service supply contracts shift to the FPFR product supplier the responsibility to cover the cost of capacity for the applicable portion of the default service load. So, it is reasonable to conclude that FPFR default service suppliers' bid prices are based on the suppliers' expectations about future PJM capacity prices.
- Network Integration Transmission Service ("NITS") – NITS costs are assessed by PJM to compensate transmission owners within the PJM footprint for the costs of their transmission system. These costs are allocated to LSEs based on their customers' network service peak load values ("NSPLs"). UGI's FPFR default service supply contracts shift to the FPFR product supplier the responsibility to cover the cost of transmission for the applicable portion of the default service load. So, it is reasonable to

[4] A block-and-spot approach involves managing an energy supply portfolio consisting of fixed-quantity, fixed-price block energy products supplemented with spot market transactions to cover the mismatch between the fixed quantities of fixed-price energy supply purchased and actual load requirements. Other supply components, such as capacity, ancillary services, etc., are generally purchased directly from the PJM Interconnection LLC ("PJM"). Currently, a 25% cross section of the default service supply for UGI's GSR-1 group is secured through a block-and-spot approach.

[5] A FPFR product approach involves procuring FPFR products on a competitive basis to satisfy the default service supply needs. Each FPFR product obligates the seller of the product to satisfy a specified percentage of all the applicable default service customers' supply requirements in every hour of the delivery period, regardless of the default service customers' instantaneous changes in energy consumption, regardless of how frequently customers switch to or from default service, and regardless of how the seller's cost to satisfy its supply obligation may change. The seller is paid a predetermined price per megawatt-hour for this service. Currently, a 75% cross section of the default service supply for UGI's GSR-1 group is secured through a FPFR product approach.

conclude that FPFR default service suppliers' bid prices are based on the suppliers' expectations about these costs.

- Other Costs – Energy, capacity, and transmission costs in aggregate generally represent the vast majority of the overall cost of default service supply. However, there are other costs. These include the costs of ancillary services and other PJM services that are billed directly by PJM.[6] They also include the costs of Alternative Energy Credits.[7] Furthermore, there are costs that result from the risks associated with default service supply. Such risks are often associated with customer migration and its effect on the default service volumes to be supplied, usage and wholesale market price uncertainty, potential changes in laws and regulations that could impact costs, and credit-related costs. Under the FPFR product approach, the costs associated with these risks are embedded in the dollar-per-megawatt-hour price of the FPFR product. The FPFR product supplier guarantees fixed prices regardless of how the actual load and wholesale market price levels change from hour to hour, so the supplier assumes the financial impacts of these risks. UGI holds open solicitations for its FPFR products, helping to ensure the achievement of competitive prices for the FPFR product suppliers to assume these risks. Under the block-and-spot approach, the same price guarantees are not provided to customers, so more of these risks are borne by the customers themselves in the form of potential increases in rates. Consequently, neither the FPFR product approach nor the block-and-spot approach avoids these risks, but instead the choice of approach simply determines who bears the risks, and the costs associated with these risks can be estimated from the prices achieved in open solicitations for FPFR products.

The analysis of the relative cost of default service supply for UGI's residential and non-residential GSR-1 customers is forward looking in that it utilizes market prices for future periods, as of May 31, 2022.[8] However, the analysis also relies on relevant data stretching back to early 2017, the beginning of the UGI DSP III period. Furthermore, for some parts of the analysis in which additional data would be relevant and useful, data is used from as early as 2011. The data and methodologies used in the analysis are described below, and all workpapers supporting this analysis accompany this study.

The relative cost analysis of residential versus non-residential GSR-1 default service supply requires forecasting the energy cost, capacity cost, NITS cost, and other costs (as described above) on a dollars-per-megawatt-hour basis for each of the two customer groups, summing the component costs, and comparing the sums. This comparison can be illustrated graphically, as shown below.

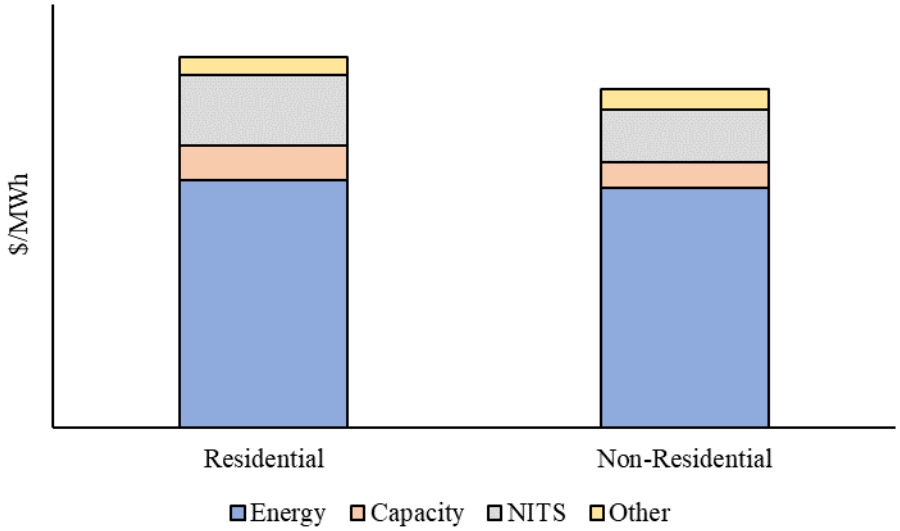
---

[6] Some of these costs are credits, such as marginal loss credits (monetary amounts that PJM allocates to Load Serving Entities that are reflective of overcollections of line loss costs embedded in wholesale hourly energy prices) and auction revenue rights credits (monetary amounts that PJM allocates to Load Serving Entities and that reflect the revenues in PJM's auctions of Financial Transmission Rights).

[7] The Alternative Energy Portfolio Standards Act of 2004, P.L. 1672, No. 213 ("AEPS Act") requires LSEs to include specific percentages of electricity over time from alternative energy resources in the electricity that they sell to Pennsylvania customers. LSEs meet this requirement by utilizing AECs generated by qualified alternative energy sources to demonstrate compliance with the AEPS Act.

[8] For the delivery periods, June 2023 to May 2025, we used the applicable June 2023 – May 2024 capacity price published by PJM on June 21, 2022.

Illustrative Default Service Supply Cost Build-Up



The first three cost components illustrated above (i.e., energy, capacity, and NITS) are directly estimated based on forward-looking prices, load forecasts, and actual historical hourly price and customer usage patterns. For example, with respect to energy, forward market prices for block energy reflect the expected levels of energy prices, and historical hourly price and load patterns are used to capture differences between the costs of supplying block energy and the costs of supplying load-following energy. With respect to capacity, PJM's Reliability Pricing Model ("RPM") capacity market provides information in advance about capacity prices and volumes. NITS costs are based on NITS tariff rates. The fourth cost component, "other costs," is estimated by studying the actual prices obtained in solicitations for FPFR products that were held during a period of approximately five years, and subtracting the associated estimates of energy, capacity, and NITS, as applicable, to isolate the aggregate market-based cost of this "other costs" component.

The following subsections describe the methodology and data sources used to estimate each of the four cost components. Furthermore, the Appendix provides a table of the main sources of data.

B. Energy Cost Estimation

Several steps are involved in the development of estimates of the load-following energy cost for each applicable customer group.[9] The remainder of this subsection describes in detail the estimation process.

[9] These estimates may not reflect all the risk-related costs of load-following energy supply. For example, costs can arise due to the uncertainty about overall wholesale energy price levels, the uncertainty about overall load levels, and the correlations between them. Furthermore, there may be risk-related costs associated with the possibility that overall average wholesale energy price levels do not match the values implied by forward prices. These risk-related costs are captured in the "other costs" component.

Step #1: Assemble the PJM Western Hub block energy forward prices for the applicable monthly on-peak and off-peak periods.

PJM Western Hub block energy forward prices with a trade date of May 31, 2022, for the applicable monthly on-peak and off-peak periods, are collected. Forward prices are provided by S&P Global Platts M2MS-Power North American Electricity forward price product.

Step #2: Calculate differences in marginal losses between PJM Western Hub and UGI.

Average hourly differences in marginal losses between PJM Western Hub and UGI are measured separately for the on-peak period and the off-peak period, across the 24 historical months ending with the month immediately preceding the trade date associated with the PJM Western Hub forward prices collected in Step #1. Day-ahead marginal loss data is used, and each average difference is recorded as a percentage of the associated average PJM Western Hub day-ahead LMP.

Step #3: Calculate differences in congestion between PJM Western Hub and UGI.

Differences in congestion between PJM Western Hub and UGI are based on the results of PJM's Financial Transmission Rights ("FTR") auctions. The results of these auctions reflect market-based expectations of forward-looking differences in congestion between delivery locations. For a given delivery period, data from the most recent FTR annual and long-term auctions (as of the trade date associated with the PJM Western Hub forward prices collected in Step #1) is used. The delivery periods in these auctions correspond with entire June through May periods, with separate delivery periods for on-peak versus off-peak periods. The congestion difference for a given delivery period is recorded as a percentage of the associated average PJM Western Hub forward price for that delivery period, as of the trade date associated with the bid due date of the respective FTR auction.

Step #4: Apply the basis differentials in Steps #2 and #3 to estimate the UGI block energy forward prices for the applicable monthly on-peak and off-peak periods.

To estimate the UGI monthly on-peak and off-peak block energy forward prices, the marginal loss and congestion differences calculated in Steps #2 and #3 are applied to the respective monthly on-peak or off-peak PJM Western Hub block energy forward prices from Step #1. For each monthly on-peak or off-peak delivery period, this can be expressed algebraically as follows:

$$P_{UGI} = P_{PJMWesternHub} * \left[1 + \left(Marginal\ Loss\%_{UGI\ Minus\ PJMWesternHub}\right) + \left(Congestion\%_{UGI\ Minus\ PJMWesternHub}\right)\right]$$

Step #5: Calculate preliminary energy costs based on historical hourly energy prices and hourly loads.

The dollars-per-megawatt-hour cost of supplying the load-following energy consumed by

residential or non-residential customers differs from block energy prices. Customers' hourly loads vary from hour to hour, whereas block energy refers to a constant volume delivered in each hour. Wholesale spot energy prices also vary by hour. Consequently, hourly differences between customer loads and block energy volumes must be met with spot purchases or sales of varying quantities and prices. Furthermore, there tends to be a positive correlation between hourly customer loads and hourly energy prices. Energy prices tend to be higher during periods of higher customer loads.

To capture differences between the dollars-per-megawatt-hour cost of supplying block energy quantities and supplying load-following energy quantities for a given customer group, historical hourly customer loads for the applicable customer group and historical hourly real-time LMPs are analyzed.[10] Specifically, for a given customer group, for a given on-peak or off-peak period of a given month of the year, the historical real-time UGI LMPs and hourly loads from the same month and on-peak or off-peak period of a previous year are gathered, and the associated overall energy cost is calculated. This is repeated using price data from multiple previous years to capture different possibilities of hourly loads and prices, all of which are reflective of actual market data.

Step #6: Scale the preliminary energy costs to forward-looking market price levels.

In Step #5, a preliminary overall energy cost for each given on-peak or off-peak period of a given month of the year is calculated, for each of multiple historical years. Next, each of these values is scaled up or down by the ratio of the applicable UGI forward block energy price (calculated in Step #4) to the straight average of the historical real-time LMPs during the given historical monthly on-peak or off-peak period, so the resulting cost value is consistent with the market price level associated with the applicable UGI forward block energy price. The applicable resulting monthly on-peak and off-peak cost values for each given historical year are then summed and divided by the sum of the associated monthly on-peak and off-peak historical loads, to determine a load-weighted energy cost using data from each given historical year on a dollars-per-megawatt-hour basis.[11] These values are then averaged to develop a final estimate of the cost of supplying load-following energy. The result is therefore consistent both with the forward energy prices and with actual hourly price and load patterns. The following table shows an illustrative, example calculation for the July 2022 on-peak period.

[10] UGI load data is limited to load values through July 2021 because residential versus non-residential GSR-1 load data was provided through that date. Subject to that constraint for UGI load data, for the purposes of analysis of default service supply solicitations used to calculate "other costs," it is assumed that load data through the preceding November is available for any spring solicitation and it is assumed that load data through the preceding May is available for any fall solicitation.

[11] An additional adjustment, specific to the calculation of UGI energy cost estimates, is also made. UGI has stated that the payments made to its FPFR default service suppliers reflect the contracted winning bid prices applied to the load values before deration factors are applied, as opposed to applying the prices to the derated load values. However, hourly LMPs apply to derated loads. Consequently, an adjustment, based on historical deration factors, is made to the UGI energy cost estimates to make these energy cost estimates applicable to load values before deration factors are applied. Such adjustments are not needed elsewhere in the overall analysis because the reported UGI loads used in this study are the loads before deration factors are applied.

Illustrative Example Calculation of Estimated July 2022 On-Peak Energy Cost

Estimated July 2022 On-Peak Energy Cost as of May 31, 2022, for the Residential Customer Group						
Historical Month	**Historical Load (GWh)**	**Historical Average Hourly LMP ($/MWh)**	**Historical Supply Cost ($)**	**Forward Block Price ($/MWh)**	**Scaled Supply Cost ($)**	**Scaled Supply Cost ($/MWh)**
	[A]	[B]	[C]	[D]	[E]=[C] * [D] / [B]	[F] =[E] / [A]
Jul-11	22,089	$86.50	$2,151,654	$142.65	$3,548,473	$160.64
Jul-12	24,508	$60.43	$1,646,485	$142.65	$3,886,531	$158.58
Jul-13	26,217	$59.91	$1,766,137	$142.65	$4,205,463	$160.41
Jul-14	22,278	$45.63	$1,102,550	$142.65	$3,446,983	$154.72
Jul-15	24,673	$33.23	$908,784	$142.65	$3,901,053	$158.11
Jul-16	24,452	$36.74	$934,293	$142.65	$3,627,117	$148.34
Jul-17	21,442	$34.28	$787,786	$142.65	$3,277,892	$152.87
Jul-18	24,290	$35.67	$914,557	$142.65	$3,657,734	$150.59
Jul-19	24,868	$27.44	$714,993	$142.65	$3,717,316	$149.48
Jul-20	30,683	$24.13	$770,304	$142.65	$4,554,409	$148.43
Jul-21	25,646	$35.94	$946,201	$142.65	$3,755,151	$146.43
Average Estimate of July '22				**$142.65**		**$153.51**

In the example above, historical hourly loads and LMPs are used to calculate the historical energy supply cost [C]. Because of the hourly load and price patterns and the correlations between them, the energy cost [C] is greater than the product of the total load [A] and the average hourly LMP [B]. However, the historical cost [C] is not a reasonable estimate of the future cost because expected future overall market price levels differ from historical outcomes. To account for the difference in market conditions, the historical energy supply cost [C] is scaled by the ratio of the forward block energy price [D] to the historical average hourly LMP [B], resulting in the scaled energy cost [E]. This value is then divided by the sum of the hourly loads to determine the load-weighted energy cost estimate on a dollars-per-megawatt-hour basis [F].[12] The result reflects both expected overall market price levels and actual hourly price-load relationships observed in the market.

C. Capacity Cost Estimation

The estimated cost of capacity is based largely on two factors: the capacity price in dollars-per-megawatt-day, and the megawatt amount of the unforced capacity ("UCAP") obligation associated with the load and applicable to the capacity price. The capacity price is published by PJM for each period for which an RPM auction has cleared, and it is assumed that the capacity price remains constant for periods beyond the last period for which an RPM auction has cleared. PJM publishes an estimated zonal UCAP obligation for each period for which an RPM auction has cleared, and the zonal UCAP obligation forms the basis of the estimated default service UCAP obligation. Specifically, recent Peak Load Contribution ("PLC") values for the zone and for the applicable class load are gathered. The default service PLC is calculated by multiplying

[12] For illustrative purposes of showing values only for this specific period, the division by the sum of the hourly loads is performed only for this specific period.

the class PLC by the ratio of default service load to class load in the most recent historical month available corresponding to the same calendar month. The default service UCAP obligation is calculated as the product of the zonal UCAP obligation and the ratio of the default service PLC to the zonal PLC. The estimated default service capacity cost on total dollar basis is then calculated as the product of the applicable capacity price, the number of days in the month, and the applicable default service UCAP obligation. The capacity cost on a dollars-per-megawatt-hour basis is then calculated as the sum of estimated capacity costs across the applicable periods, divided by the sum of the forecasted megawatt-hour loads across the applicable periods.

The forecasted megawatt-hour load is based on PJM's most recent zonal load forecast and historical relationships between the applicable customer group's load and the zonal load. On or around January of each year, PJM publishes a forecast of monthly zonal loads.
Two steps are taken to convert the zonal load forecast to the default service load forecast for the applicable customer group. First, the applicable customer group's forecasted total (default service and choice, in aggregate) load is calculated. For each given calendar month, the average of the three fractions of the applicable customer group's load divided by zonal load for the given calendar month in three historical years is calculated, and that value is applied to the forecasted zonal load for the same calendar month in the future. For example, the fractions for three recent months of May are averaged, and that value is applied to the forecasted zonal load for future May periods. The second step involves calculating and applying the fractions of the applicable customer group's total load that is retained as default service. For a given calendar month's forecasted load, the fraction is based on the applicable customer group's total load and default service load pertaining to the same calendar month during the most recent twelve months for which load data is available. The overall calculation of the forecasted default service load for the applicable customer group is expressed as follows:

$$Forecast\ Load_{DefaultServiceGroup} = ZonalForecast\ *\ HistoricalClassFraction_{TotalGroup/Zonal} *\ Historical\ RetainedFraction_{DefaultServiceGroup/TotalGroup}$$

D. Network Integration Transmission Service Cost Estimation

The cost of NITS in each delivery month is calculated by multiplying the estimated NITS tariff rate denominated in dollars-per-megawatt-day by the default service NSPL obligation and the number of days in the month.[13] The default service NSPL obligation is calculated by multiplying the class NSPL by the ratio of default service load to class load in the most recent historical month available corresponding to the same calendar month. The NITS cost on a dollars-per-megawatt-hour basis is then calculated as the sum of estimated NITS costs across the applicable periods, divided by the sum of the forecasted megawatt-hour loads across the

[13] For the NITS cost projection as of May 31, 2022, estimated future NITS rates are assumed to be the published NITS rates applicable starting June 1, 2022. For the purposes of analysis of default service supply solicitations used to calculate "other costs," for any spring solicitation it is assumed that estimated NITS rates for all dates on or after the upcoming June 1 are the published NITS rates applicable starting the upcoming June 1. For the purposes of analysis of default service supply solicitations used to calculate "other costs," for any fall solicitation it is assumed that estimated NITS rates for all dates are the current NITS rates.

applicable periods. The process for determining the forecasted megawatt-hour loads is described previously.

E. "Other Costs" Estimation

As noted previously, the fourth cost component, "other costs," is estimated by studying the results of actual prices obtained in solicitations for FPFR products that were held during a period of approximately five years, and subtracting the associated estimates of energy, capacity, NITS, etc., as applicable, to isolate the aggregate market-based cost of this "other costs" component.

UGI's FPFR product solicitations do not provide information about the relative levels of "other costs" for residential versus non-residential GSR-1 default service supply because these two groups are aggregated together for the purpose of procuring default service supply. However, PECO, a nearby Pennsylvania utility, conducts separate FPFR product solicitations to supply its residential ("PECO Residential Group") default service load and the default service load of its non-residential customers with peak demands less than or equal to 100 kW ("PECO Small Commercial Group"). These two PECO customer groups are aligned with the two UGI customer groups relevant to this study, as the relevant UGI customer groups are defined as the residential group and the non-residential group of customers with peak loads less than 100 kW. By analyzing the results of the PECO FPFR product solicitations for both the PECO Residential Group and the PECO Small Commercial Group, and the results of the UGI GSR-1 FPFR product solicitations, reasonable estimates of the "other costs" associated with UGI's residential default service supply and the "other costs" associated with UGI's non-residential GSR-1 default service supply can be developed.

As the first step, the results of each solicitation for PECO Residential Customer Group FPFR default service supply products and PECO Small Commercial Customer Group FPFR default service supply products since early 2017 are analyzed. For a given FPFR default service supply product procured in a solicitation for a PECO customer group, the reported winning bid price for the FPFR product solicited is recorded. Next, estimates of the applicable cost of energy and cost of capacity, both expressed in terms of dollars-per-megawatt-hour, are subtracted from the winning bid price. These two costs are estimated using a calculation methodology that is consistent with the methodology described above to estimate UGI's energy and capacity costs. For the analysis of the PECO solicitations, data pertaining to the applicable PECO customer groups is used, the data is limited to that available as of the time of the respective PECO solicitation being analyzed, and the data used is that applicable to the delivery period of the given FPFR product being analyzed. Unlike UGI's FPFR products, which require the winning bidders to cover the cost of NITS, PECO's FPFR products do not require the winning bidders to cover the cost of NITS. Consequently, in the analyses of the PECO FPFR product solicitations, the difference, after subtracting the energy and capacity cost estimates from the winning bid price, represents the estimate of "other costs" for the given applicable FPFR default service supply product procured in the given solicitation for the given PECO customer group.

Next, the estimated "other costs" pertaining to the PECO supply solicitations for the PECO Residential Customer Group are averaged to develop an estimate of this group's "other costs" of

$5.05/MWh, and the estimated "other costs" pertaining to the PECO supply solicitations for the PECO Small Commercial Customer Group are averaged to develop an estimate of this group's "other costs" of $5.85/MWh. A load-weighted average of these two values is then calculated by weighting the two values by the forecasted default service loads associated with their counterpart UGI customer groups, which are the residential customer group and the non-residential GSR-1 customer group, respectively, to develop a UGI-load-weighted average of the two PECO "other costs" estimates. This load-weighted average value is $5.25/MWh.

The results of each solicitation for UGI GSR-1 FPFR default service supply products since early 2017 are then analyzed. For a given applicable FPFR default service supply product procured in a given solicitation, the reported winning bid price for the FPFR product solicited is recorded. Next, estimates of the applicable cost of energy, cost of capacity, and cost of NITS, all expressed in terms of dollars-per-megawatt-hour, are subtracted from the winning bid price. These three costs are estimated using a calculation methodology that is consistent with the methodology described above to estimate UGI's energy, capacity, and NITS costs. For the analysis of the UGI solicitations, the data is limited to that available as of the time of the respective UGI solicitation being analyzed, and the data used is that applicable to the delivery period of the given FPFR product being analyzed. The difference, after subtracting the energy, capacity, and NITS cost estimates from the winning bid price, is then recorded for the given applicable FPFR default service supply product procured in the given solicitation. The differences, across all the UGI FPFR default service supply products procured in the UGI solicitations, are then averaged, resulting in an estimate of the UGI GSR-1 "other costs" of $5.98/MWh.

The next steps of the analysis combine the results of the analysis of the PECO Residential Customer Group supply solicitations, the PECO Small Commercial Customer Group supply solicitations, and the UGI GSR-1 supply solicitations. First, $0.42/MWh, which is the historical dollars-per-megawatt-hour cost of certain PJM charges which UGI FPFR product suppliers must cover, but that PECO FPFR product suppliers are not required to cover, is subtracted from the estimate of the UGI GSR-1 "other costs" of $5.98/MWh, to calculate a $5.56/MWh value for UGI GSR-1 "other costs" that is effectively comparable to the $5.25/MWh value identified above for the PECO "other costs" for a comparable default service load mix. Since the value of $5.56/MWh calculated from the analysis of the UGI solicitations is higher by a factor of 1.061 than the $5.25/MWh composite value calculated from the analysis of the PECO solicitations, the individual customer group values for PECO of $5.05/MWh for the PECO Residential Customer Group and $5.85/MWh for the PECO Small Commercial Customer Group are scaled by a factor of 1.061 to develop values for UGI of $5.36/MWh for the residential customer group and $6.21/MWh for the non-residential GSR-1 customer group. Finally, the $0.42/MWh value, which again is the historical dollars-per-megawatt-hour cost of certain PJM charges which UGI FPFR product suppliers must cover, is added back to calculate estimated "other cost" values of $5.78/MWh for the UGI residential customer group and $6.63/MWh for the UGI non-residential GSR-1 customer group.

In sum, the "other costs" estimates for the UGI residential customer group and the UGI non-residential GSR-1 customer group represent the default service supply costs that are not captured in the energy, capacity, and NITS cost estimates, including costs that result from the

risks associated with default service supply. Furthermore, these estimates are based on solicitation results for 58 FPFR default service supply products procured in 22 solicitations over approximately the past five years.

UGI GSR-1 Solicitations and Products Analyzed

Default Service Plan	Solicitation	Bid Due Date	Delivery Period	# of Months	Products Analyzed
III	Spring 2017	4/11/2017	Jun 17 – Nov 17	6	Combined Residential and Non-Residential GSR-1
	Spring 2017	4/11/2017	Jun 17 – May 18	12	
	Fall 2017	10/10/2017	Dec 17 – Nov 18	12	
	Spring 2018	4/24/2018	Jun 18 – May 19	12	
	Fall 2018	10/16/2018	Dec 18 – Nov 19	12	
	Spring 2019	4/16/2019	Jun 19 - May 20	12	
	Fall 2019	10/15/2019	Dec 19 - Nov 20	12	
	Spring 2020	4/21/2020	Jun 20 - May 21	12	
	Fall 2020	10/13/2020	Dec 20 - May 21	6	
IV	Spring 2021	4/20/2021	Jun 21 - Nov 21	6	
	Spring 2021	4/20/2021	Jun 21 - May 22	12	
	Spring 2021	4/20/2021	Jun 21 - May 23	24	
	Fall 2021	10/12/2021	Dec 21 - Nov 22	12	
	Spring 2022	4/20/2022	Jun 22 – May 23	12	

PECO Residential and Small Commercial Solicitations and Products Analyzed

Default Service Plan	Solicitation	Bid Due Date	Delivery Period	# of Months	Products Analyzed
IV	Spring 2017	3/15/2017	Jun 2017–May 2018	12	Product #1: Residential Product #2: Small Commercial
	Spring 2017	3/15/2017	Jun 2017–May 2019	24	
	Fall 2017	9/26/2017	Dec 2017– Nov 2018	12	
	Fall 2017	9/26/2017	Dec 2017– Nov 2019	24	
	Spring 2018	3/13/2018	Jun 2018–May 2019	12	
	Spring 2018	3/13/2018	Jun 2018–May 2020	24	
	Fall 2018	9/25/2018	Dec 2018–Nov 2019	12	
	Fall 2018	9/25/2018	Dec 2018–Nov 2020	24	
	Spring 2019	3/12/2019	Jun 2019–May 2020	12	
	Spring 2019	3/12/2019	Jun 2019–May 2021	24	
	Fall 2019	9/24/2019	Dec 2019–Nov 2020	12	
	Fall 2019	9/24/2019	Dec 2019–Nov 2021	24	
	Spring 2020	3/10/2020	Jun 2020–May 2021	12	
	Spring 2020	3/10/2020	Jun 2020–May 2022	24	
	Fall 2020	9/29/2020	Dec 2020 – Nov 2021	12	
	Fall 2020	9/29/2020	Dec 2020 – Nov 2022	24	
V	Spring 2021	3/2/2021	Jun 2021–May 2022	12	
	Spring 2021	3/2/2021	Jun 2021–May 2023	24	
	Fall 2021	9/28/2021	Dec 2021 – Nov 2022	12	
	Fall 2021	9/28/2021	Dec 2021 – Nov 2023	24	
	Spring 2022	3/15/2022	Jun 2022–May 2023	12	
	Spring 2022	3/15/2022	Jun 2022–May 2024	24	

F. Development of Relative Costs by Customer Group

Once all the component cost estimates are calculated on a dollars-per-megawatt-hour basis as described above, the respective residential cost estimates are summed, and the respective non-residential GSR-1 cost estimates are summed. The two resulting total cost estimates are then weighted by each customer group's default service load to develop a composite GSR-1 total cost estimate. By comparing each customer group's total cost estimate to the composite GSR-1 total cost estimate, the estimated relative costs by customer group, expressed as a factor of the composite GSR-1 cost, are determined. The following tables depict the results for each of the three June through May periods remaining during UGI's DSP IV period.

Relative Cost Analysis: June 2022 – May 2023

	Residential	Non-Residential GSR-1	Composite GSR-1
Energy ($/MWh)	$108.06	$104.34	
Capacity ($/MWh)	$8.85	$6.51	
NITS ($/MWh)	$20.63	$15.27	
Other Costs ($/MWh)	$5.78	$6.63	
Total ($/MWh)	$143.33	$132.74	$140.75
Load (MWh)	530,279	170,711	700,990
Relative Cost Factor	**1.02**	**0.94**	**1.00**

Relative Cost Analysis: June 2023 – May 2024

	Residential	Non-Residential GSR-1	Composite GSR-1
Energy ($/MWh)	$65.37	$63.15	
Capacity ($/MWh)	$4.57	$3.36	
NITS ($/MWh)	$20.70	$15.33	
Other Costs ($/MWh)	$5.78	$6.63	
Total ($/MWh)	$96.41	$88.47	$94.48
Load (MWh)	529,951	170,476	700,427
Relative Cost Factor	**1.02**	**0.94**	**1.00**

Relative Cost Analysis: June 2024 – May 2025

	Residential	Non-Residential GSR-1	Composite GSR-1
Energy ($/MWh)	$55.69	$53.46	
Capacity ($/MWh)	$4.59	$3.37	
NITS ($/MWh)	$20.80	$15.41	
Other Costs ($/MWh)	$5.78	$6.63	
Total ($/MWh)	$86.86	$78.87	$84.92
Load (MWh)	525,870	169,145	695,015
Relative Cost Factor	**1.02**	**0.93**	**1.00**

The following table provides a summary of the relative costs across the three periods.

Percentage Differences in Estimated Dollars-Per-Megawatt-Hour Supply Costs

	Residential vs. Composite GSR-1	Non-Residential GSR-1 vs. Composite GSR-1	Residential vs. Non-Residential GSR-1
June 2022 – May 2023	+2%	-6%	+8%
June 2023 – May 2024	+2%	-6%	+8%
June 2024 – May 2025	+2%	-7%	+9%

III. Evaluation of Combined Versus Separate Procurements

The Commission-approved DSP IV Settlement states that the relative cost evaluation should address "both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement."[14] This section of the study addresses costs and risks associated with procuring GSR-1 default service supply through combined supply products versus through separate supply products for residential versus non-residential GSR-1 customers. The subsequent section of this study presents a possible cost allocation approach under a combined procurement, based on the type of analysis of the relative cost for residential and non-residential GSR-1 customer groups presented in the previous section.

Insights can be drawn about the costs and risks associated with an approach in which the default service supply for UGI's GSR-1 group is procured through separate products for residential supply and non-residential GSR-1 supply versus an approach in which the default service supply is procured for the combined GSR-1 group, but there is insufficient data to quantify the expected overall difference in supply cost between these two approaches with a useful confidence level. UGI's historical default service plans have not entailed procurements of both separate products and combined products, which would facilitate a reasonable quantification of the expected overall difference in UGI supply cost between separate and combined product approaches. Further, even if another service area had a history that offers supply cost data for both separate and combined product approaches, certain aspects of UGI's situation, such as its size, make it potentially materially different from the circumstances in other service areas.

While there is insufficient data to quantify, with a useful confidence level, the expected overall difference in supply cost between the combined and separate product approaches for UGI's GSR-1 default service supply, empirical evidence and analysis indicate that splitting the GSR-1 customer group into separate residential and non-residential groups for supply procurement purposes would entail unnecessary cost-related risks. This is described in the remainder of this section.

UGI is among the smallest electric utilities whose customers are provided a choice regarding their retail Electric Generation Supplier ("EGS"). Further separating its GSR-1 customer group into further subgroups for supply procurement purposes could result in solicited supply amounts for a single customer group that are so small that supplier interest in them would be inadequate to receive competitive bids, or to receive bids at all. Indeed, the administrative costs of formulating bids and managing the resultant contracts, as well as the transactional costs associated with managing supply obligations, may make the proposition of bidding to supply such small amounts for a customer group unattractive to potential bidders.

To help illustrate this point, the following table provides estimates of megawatt-hours of supply solicited in Pennsylvania utilities' default service supply solicitations. Specifically, for each Pennsylvania utility, we studied the utility's default service supply solicitation cycle for each separate customer group for which the utility solicits FPFR products with somewhat comparable

[14] DSP IV Settlement, pp. 7-8.

delivery periods to UGI's delivery periods.[15] For each utility, the smallest estimated aggregate number of megawatt-hours of default service supply solicited (in the form of FPFR supply products with somewhat comparable delivery periods) for a customer group in a single solicitation was then recorded in the following table.[16]

Indicative Analysis of Pennsylvania Utilities' FPFR Default Service Solicitations

Utility	Smallest Estimated Volume for a Single Customer Group in a Single Solicitation (MWh)	Customer Group
Citizens' and Wellsboro	280,064	Residential and Small Commercial
Duquesne Light Company	245,164	Small Commercial & Industrial
PECO	989,460	Small Commercial
PPL	890,438	Small Commercial & Industrial
FirstEnergy – Met-Ed	59,744	Commercial
FirstEnergy – Penelec	67,020	Commercial
FirstEnergy – Penn Power	47,950	Commercial
FirstEnergy – West Penn Power	143,911	Commercial
UGI (if GSR-1 were split)	**42,272**	**GSR-1 Non-Residential**

As shown in the table, separating UGI's GSR-1 customer group into a residential group and a non-residential group for supply procurement purposes would result in the new GSR-1 Non-Residential customer group having the smallest aggregate number of megawatt-hours of default service supply solicited (in the form of FPFR products with somewhat comparable delivery periods) for any single customer group in any single solicitation in all of Pennsylvania. Consequently, prospective suppliers may be inclined not to expend the effort to prepare and submit competitive bids for the chance of being awarded such small volumes. This unnecessary risk could be further compounded by the fact that the overall aggregate volumes of supply solicited in UGI's default service supply solicitations are already relatively small compared to other utilities.[17]

While UGI has held many successful solicitations for default service supply, it has also experienced unsuccessful solicitations for default service supply for smaller customers:

- UGI's March 2012 solicitation for load following default service supply for its non-residential customers with peak loads less than 500 kW was deemed non-competitive

[15] For the purposes of this indicative analysis, "somewhat comparable" delivery periods are identified as delivery periods of six months or more. It was observed that delivery periods that are shorter than six months may have notably less risk of significant changes in market conditions, which suppliers must manage.

[16] Megawatt-hour values are based on actual annual June 2020 – May 2021 default service values from the applicable utility. For example, if the applicable supply solicited is in the form of two-year products comprising (in aggregate) 25% of the default service supply for the applicable customer group, and the overall default service supply for that customer group during June 2020 – May 2021 was 1.5 million megawatt-hours, the applicable value is 2 years x 25% x 1.5 million megawatt-hours per year = 750,000 megawatt-hours.

[17] Along these lines, while values in the table associated with some of FirstEnergy's utilities are not enormously different from the UGI value in the table, FirstEnergy's Pennsylvania utilities procure their default service supply through single solicitations in which all the utilities participate together, significantly increasing the total amount of supply being solicited in a single solicitation.

and its results were rejected.[18]

- UGI's October 2012 solicitation for load following default service supply for its non-residential customers with peak loads less than 500 kW was deemed non-competitive and its results were rejected.[19]
- No bids were received in UGI's October 2014 solicitation for load following default service supply for its GSR-1 customers.[20]

These outcomes are evidence that unsuccessful solicitations are a possibility. Consequently, it may not be preferable to make any change that could decrease prospective suppliers' inclination to bid sufficiently on certain portions of the supply, such as a change that entails breaking the GSR-1 supply group into even smaller groups, as that could entail significant risks of unsuccessful solicitations for portions of the supply.

Separating UGI's GSR-1 customer group into a residential group and a non-residential group for supply procurement purposes would also entail increased administrative costs. Specifically, UGI estimates that this approach would increase the annual administrative costs of the utility or its procurement monitor by almost $25,000 in aggregate, as shown in the following table.

UGI Estimate of the Increased Administrative Costs from Separating GSR-1 into Residential and Non-Residential GSR-1

Category	Estimated Annual Cost Increase	Notes
RFP Monitoring Service	$13.0K	Based on an estimate of $6K-$7K per solicitation, provided by the procurement monitor
Supply Procurement	$8.1K	Estimated increase of 50% of internal time involved to procure, plus eight hours per month for additional data preparation
Allocation of Supply Costs to Groups	$1.7K	Estimated increase of 50% of internal time involved to file with the Commission
Gross Receipts Taxes	$1.4K	GRT rate of 5.9%
TOTAL	**$24.2K**	

In sum, empirical evidence and analysis indicate that splitting the GSR-1 customer group into separate residential and non-residential groups for supply procurement purposes would entail unnecessary cost-related risks. Separate from these risks, UGI also estimates that administrative costs would be higher if the GSR-1 group were split. Furthermore, as explained in the next section, a reasonable cost allocation approach could be applied to the costs that result from the solicitations to supply the combined GSR-1 group, if so desired. Given these considerations, maintaining UGI's combined GSR-1 group may be the more prudent approach.

[18] Secretarial Letter Re: UGI Utilities, Inc. – Results of Request for Proposals Process Proposals for the March 2012 Group 2 Load Following RFP, Pennsylvania Public Utility Commission, Docket No. P-2009-2135496, March 27, 2012.

[19] Secretarial Letter Re: UGI Utilities, Inc. – Results of Request for Proposals Process Proposals for the October 2012 Group 2 Load Following RFP, Pennsylvania Public Utility Commission, Docket No. P-2009-2135496, October 23, 2012.

[20] Secretarial Letter Re: UGI Utilities, Inc. – Results of Request for Proposals Process Proposals for the October 2014 GSR-1 Load Following/Block RFPs, Pennsylvania Public Utility Commission, Docket No. P-2013-2357013, October 8, 2014.

IV. Possible Cost Allocation Approach to Reflect Relative Cost Differences in Rates

The Commission-approved DSP IV Settlement states that the relative cost evaluation should address "both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement."[21] In this section, we outline a reasonable cost allocation approach that could be applied to translate the cost on a dollars per megawatt-hour basis for combined supply for UGI's residential and non-residential GSR-1 customers into rates that reflect the relative costs for each of these two customer groups. This cost allocation approach is intended to be simple, it is based on a default service supply cost allocation methodology that is already applied in Pennsylvania, and importantly it is designed to reasonably reflect the difference in cost of providing default service supply to residential customers and non-residential GSR-1 customers.

The cost allocation approach would be implemented through a simple adjustment to the process that UGI currently uses to calculate its GSR-1 Rate. The GSR-1 Rate is the rate by which UGI recovers the default service supply costs for the GSR-1 group, and it is assessed in terms of cents per kilowatt-hour of load. As explained in UGI's Tariff Book,[22] this rate is calculated as the sum of three components that are expressed in terms of cents per kilowatt-hour, and then grossed up for the applicable Pennsylvania Gross Receipts Tax Rate:

- "Energy Costs" or "EC" – Projected direct and indirect purchased power costs incurred by UGI to acquire electric supply for the GSR-1 group.
- "Energy Cost Adjustment" or "ECA" – Net over or under collection of the EC defined above to be refunded/recovered in the GSR-1 group.
- "Interest" or "Int" – Interest on the net over or under collection of the EC defined above to be refunded/recovered in the GSR-1 group.

To implement the cost allocation approach, factors would be applied to the EC value. The factor for residential customers would be different from the factor for non-residential GSR-1 customers. The factors would reflect the difference in expected costs to serve each of these groups, and they could be calculated using a methodology consistent with that described and applied in Section II.

In Section II, it is shown that the default service supply costs (in terms of dollars per megawatt-hour or alternately cents per kilowatt-hour) for residential and non-residential GSR-1 customers are expected to differ from the composite GSR-1 default service supply cost by the percentages in the following table.

[21] DSP IV Settlement, pp. 7-8.
[22] UGI Utilities, Inc. – Electric Division, Electric Service Tariff, issued March 22, 2022, pp. 39-40.

Percentage Differences vs. Composite in Estimated Dollars-Per-Megawatt-Hour Supply Costs

	Residential vs. Composite GSR-1	**Non-Residential GSR-1 vs. Composite GSR-1**
June 2022 – May 2023	+2%	-6%
June 2023 – May 2024	+2%	-6%
June 2024 – May 2025	+2%	-7%

For illustrative purposes, based on these findings, the factors applied to the EC value would be as follows:

- For June 2022 through May 2023, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.94 would be applied to calculate the non-residential GSR-1 default service supply rates.
- For June 2023 through May 2024, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.94 would be applied to calculate the non-residential GSR-1 default service supply rates.
- For June 2024 through May 2025, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.93 would be applied to calculate the non-residential GSR-1 default service supply rates.

If this cost allocation approach were adopted, factors could be established for a multi-year period, or they could be updated on an annual basis or another reasonable basis to reflect changes in market conditions, including changes in residential and non-residential shares of the GSR-1 default service load and changes in forward energy or capacity prices. The existing reconciliation mechanism across the GSR-1 customer group would continue to be utilized to ensure that all default service supply costs are recovered.

This basic factor-based default service cost allocation approach has precedent in Pennsylvania, as it is very similar to a cost allocation approach that has been approved by the Commission and applied in Duquesne Light's service area for almost a decade. Duquesne Light procures default service supply for its residential and lighting customers on a consolidated basis, like UGI does for its residential and non-residential GSR-1 customers. To develop its default service rates, Duquesne Light applies rate factors to its projected direct and indirect purchased power costs (expressed in terms of cents per kilowatt-hour) to acquire electric supply for the combined residential and lighting customer group, and the rate factor for residential customers is different from the factor for lighting customers.[23] This approach is similar to the cost allocation approach described in this section for UGI. Furthermore, Duquesne Light's rate factors are based on market-based cost estimates that incorporate each customer group's energy consumption patterns and capacity requirements.[24] The methodology used to develop those market-based cost estimates is similar to the methodology that is used to develop the expected relative default service supply costs presented in Section II.

[23] Duquesne Light Company, Schedule of Rates, issued March 1, 2022, pp. 103-104.

[24] Duquesne Light Statement No. 4, Petition Of Duquesne Light Company For Approval Of Default Service Plan For The Period June 1, 2021 Through May 31, 2025, Docket No. P-2020-3019522, April 20, 2020, pp. 4-7.

In sum, the Commission could consider implementing the cost allocation approach outlined in this section. This approach may better reflect the expected relative costs of supplying residential versus non-residential GSR-1 default service customers. It also may be relatively simple to implement, and the basic approach has precedent in Pennsylvania.

V. Appendix

Main Data Sources Used in the Default Service Supply Relative Cost Analysis

Type of Data	Description	Source
Locational Marginal Prices	Hourly energy prices, including congestion and loss components, for PJM nodes 51288 (PJM Western Hub), 51279 (UGI), and 51297 (PECO). Hourly prices are day-ahead	PJM Data Miner 2: http://dataminer2.pjm.com/feed/da_hrl_lmps
Financial Transmission Rights	Historical prices for annual and long-term auctions for PJM nodes 51288 (PJM Western Hub), 51279 (UGI), and 51297 (PECO)	https://www.pjm.com/markets-and-operations/ftr
Block Energy Forward Prices	Historical and contemporary forward prices for on-peak and off-peak block energy delivered at PJM Western Hub	S&P Global Platts M2MS-Power North American Electricity forward price product
UGI Class-Specific Load	Historical hourly load for residential and non-residential GSR-1 customers, both default service and choice customers	Provided by UGI
PECO Class-Specific Load	Historical hourly load for PECO residential and small-commercial customers, including both default service and choice customers	https://www.pecoprocurement.com/
PJM Zonal Load	Historical hourly load for UGI and PECO load zones	http://dataminer2.pjm.com/feed/hrl_load_metered
UGI GRP-1 residential and commercial customer PLC	Actual daily PLC values for UGI residential and commercial customers	Provided by UGI
UGI GRP-1 residential and commercial customer NSPL	Actual daily NSPL values for UGI residential and commercial customers	Provided by UGI
PECO residential and small commercial customer PLC	Actual daily PLC values for PECO residential and non-residential customers, including both default service and choice customers	https://www.pecoprocurement.com/
PJM zonal PLC	Historical PLC values by PJM RPM capacity zone	https://www.pjm.com/markets-and-operations/rpm
Network Integration Transmission Service (NITS) Rates	Rates for NITS service assessed based on NSPL	Rates for periods prior to June 1, 2022 were provided by UGI; Rate beginning June 1, 2022 downloaded from https://www.pjm.com/-/media/markets-ops/settlements/network-integration-trans-service-june-2022.ashx
PJM Load Forecasts	Forecasted annual GWh load for PJM load zones produced annually by PJM for future delivery years	https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process
RPM Prices and UCAP Obligations	Historical PJM RPM zonal capacity prices and UCAP MW obligations by zone for BRA and incremental auctions	https://www.pjm.com/markets-and-operations/rpm
Default Service Solicitation Bid Results	Historical winning bid prices for default service load-following products	Provided by UGI, https://www.pecoprocurement.com/

APPENDIX C

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division For Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029	:	Docket Nos. P-2024-3049343 G-2024-3049351

REBUTTAL TESTIMONY
OF
JESSE R. TYAHLA

UGI ELECTRIC STATEMENT NO. 1-R

Dated: August 30, 2024

I. Introduction

Q. Please state your name and address.

A. My name is Jesse R. Tyahla. My business address is UGI Utilities, Inc., 1 UGI Drive, Denver, PA 17517.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. My direct testimony, UGI Electric St. No. 1, was submitted on May 31, 2024, as Appendix B to the Petition.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the Office of Small Business Advocate ("OSBA") witness Mark D. Ewen's and Office of Consumer Advocate ("OCA") witness Serhan Ogur's arguments related to the procurement study that forms the basis for the rate allocation factors that the Company has proposed for application to residential and non-residential GSR-1 customers. I note that UGI Utilities, Inc. – Electric Division's ("UGI Electric") witness James Rouland specifically addresses the substantive benefit for both residential and non-residential GSR-1 customers of continuing the combined procurement approach.

Q. Are you sponsoring any Exhibits with your rebuttal testimony?

A. Yes, I am sponsoring one Exhibit, Exhibit JRT-1R.

II. Procurement Study/Rate Allocation Factors Issues

Q. Please briefly summarize the GSR-1 customer group.

A. As proposed, the GSR-1 customer group consists of all residential customers as well as non-residential customers with a supply peak load impact less than 100 kW.

Q. Please summarize how the Company procures default supplies for GSR-1 customers.

A. The Company procures supply for the GSR-1 customer group through a request for proposal ("RFP") process whereby the Company requests bids from electric wholesale suppliers to serve certain portions of the GSR-1 customer load over a specified time period. The Company evaluates the bids received for completeness, submits the RFP results and recommendations through its Market Monitor to the Pennsylvania Public Utility Commission ("Commission") for approval, and then transacts with the supplier(s) whose offerings were approved.

Q. Are residential and non-residential GSR-1 customers currently charged the same rate?

A. Yes, the residential and non-residential GSR-1 customers are currently charged the same Generation Supply Rate under DSP IV.

Q. Is the Company proposing to charge residential and non-residential GSR-1 customers the same Generation Supply Rate in DSP V?

A. No. Pursuant to the settlement terms in DSP IV, the Company had a procurement study completed by the Northbridge Group and as a result is proposing to apply rate allocation

factors to the GSR-1 costs, which will result in different rates for residential and non-residential GSR-1 customers.

Q. How were the rate allocation factors developed according to the procurement study?

A. The rate allocation factors were calculated by estimating the difference in expected costs to serve each of the residential and non-residential rate groups.[1] The costs for energy, capacity, transmission, and "other costs" were estimated using load samples of residential and non-residential customers. The estimated costs for each customer group were then combined into a composite estimate and then compared to the composite estimate to determine the Relative Cost Factor or allocation factor.[2]

Q. Please summarize OSBA witness Ewen's position regarding the rate allocation factors for residential and non-residential GSR-1 customers.

A. Mr. Ewen finds that the methodology and conclusion of the procurement study to be reasonable, which includes both an option for separate procurements for the residential and non-residential GSR-1 customers as well as assignment of separate rates for residential and non-residential customers. Mr. Ewen acknowledges the additional costs and risks associated with separate procurements and supports the approach of UGI Electric

[1] UGI Electric St. No. 1, Exhibit JRT-2, pp. 18-19.
[2] UGI Electric St. No. 2, Exhibit JRT-1, pp. 13-14.

continuing its procurement strategy while assigning separate GSR-1 rates to residential and non-residential customers.[3]

Q. Please summarize OCA witness Ogur's comments regarding the procurement study that was the basis for the rate allocation factors.

A. Mr. Ogur states that the procurement study was flawed in several ways impacting the results regarding the rate allocation factors including the method used to determine the "other costs" of the FPFR supplies, the omission of customer shopping or switching related cost premium for FPFR supplies, and the impact of tranche sizes in MWh volume for the residential and non-residential customer groups. In the event the Commission were to approve separate Energy Cost ("EC") rates, Mr. Ogur argues that the rate allocation factors should not be adopted based on the results of the procurement study and alternatively recommends separate procurements for the residential and non-residential customer groups.

Q. Do you agree with Mr. Ogur's criticisms of the procurement study?

A. In part. Mr. Ogur acknowledges that the key components of the supply costs, namely capacity and transmission costs to residential customers would, at least in concept, be higher than those same costs for non-residential customers due to residential customers

[3] OSBA St. No. 1, p. 8.

having lower load factors.[4] In addition, relative to spot market supplies from PJM, Mr. Ogur states that

> *"To the extent that residential customers increase their electricity usage during these high system load and high spot price hours more so than small non-residential customers do, energy costs on average for residential customers may also be higher than for small non-residential customers."*

In regard to the "other costs" and customer switching related risk premium, which would also be assumed in "other costs," the total "other costs" component represents less than 9% of the total FPFR bid prices on average from 2017 through Spring 2022. If the "other costs" were allocated in a way to bring both the residential and non-residential FPFR costs to the same price (at parity), the "other costs" portion of the total price for the residential customer group would be 2.3% to 4.5% and the non-residential group would be allocated 10.4% to 14.9% (See UGI Electric Exhibit JRT-1R). Comparatively, the historical average of "other costs" for PECO Energy Company ("PECO") customers are 9% and 11% for residential and small commercial customers, respectively.

If the "other cost" allocations represented 100% of the estimated total price difference between the residential and non-residential GSR-1 customers, the non-residential customers would have an "other costs" component 3.28 to 4.57 times higher than that of the residential customers (See Exhibit JRT-1R). In comparison, using the analysis from the procurement study, PECO's small commercial customers paid an "other costs" component that was only 1.16 times higher than that of the comparable PECO residential customers. As proposed in the procurement study, the "other costs" for GSR-1

[4] OCA St. No. 1, pp 25-26.

non-residential customers were approximately 1.15 times higher than that of the residential customers, which is in line with PECO's Residential and Small Commercial customer groups.

In reviewing the data provided by Mr. Ogur in Table 2 of his testimony, the period of 2017 through 2019 is a sample time period where the switching risk (as measured by relative standard deviation of annual shopping rates)[5] between UGI Electric and PECO Customers is the same at 0%. This is because there is no deviation in the EGS Share of Total Residential Megawatt-Hours for either company (UGI at 1%, PECO at 36% for all three years). During this time period, the PECO's small commercial customers paid an "other costs" component that ranged from 1.01 to 1.47 times that of the residential customers. As proposed in the procurement study, the "other costs" for GSR-1 non-residential customers were approximately 1.15 times higher than that of the residential customers, which is in line with sample data set for PECO's Residential and Small Commercial customer groups. This analysis demonstrates that the allocation of "other costs" for the UGI Electric GSR-1 residential and non-residential customers as provided in the procurement study is appropriate and therefore the calculation of the allocation factors for the residential and non-residential customers is reasonable.

Lastly, Mr. Ogur makes claims of the flaws in the procurement study and the results but does not offer any alternative calculation or estimate of the rate allocation factors for the residential and non-residential customer groups. Mr. Ogur proposes that the Company continue its joint procurement approach and not apply the rate allocation factors. Mr. Ogur

[5] OCA St. No. 1, pp. 31-32.

also states that if the rate allocation factors are not eliminated, that the Company should conduct separate procurements for residential and non-residential GSR-1 customers.

Q. Given the testimony of Mr. Ewen and Mr. Ogur does the Company propose any modifications to the application of separate residential and non-residential procurement factors?

A. Both customer groups, the residential and non-residential customers, benefit from each other by utilizing the joint procurement methodology and UGI witness Rouland's rebuttal testimony also addresses this benefit. The Company, Mr. Ogur, and Mr. Ewen agree that there are differences between residential and non-residential customers that can be more or less costly to serve due to their energy load profiles. Procurements from a combined standpoint tend to lead to greater tranche sizes and economies of scale, and, all else being equal, this should result in increasing competition and subsequently, lowering energy costs for both residential and non-residential customers receiving default service supply. However, the magnitude of the benefits and costs to serve of each customer group is somewhat subjective. Maintaining the status quo of combined procurements and no assessment of allocation factors for the residential and non-residential groups would be less administratively burdensome as it would require the calculation of only one GSR-1 rate and tracking and reconciliation of the GSR-1 revenues for one combined GSR-1 group as compared to two separate GSR-1 rates. In review of all concerns together, including the ultimate subjective nature of certain procurement cost elements being quantified but the clear benefits to both residential and non-residential GSR-1 customers of combined procurement, the Company believes maintaining the status quo of combined procurements

and not implementing any rate allocation factors is a reasonable balancing of all interests. Accordingly, the Company proposes removing the rate allocation factors at this time.

Q. Does this conclude your rebuttal testimony at this time?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. –	:	
Electric Division For Approval of	:	Docket Nos. P-2024-
a Default Service Plan (DSP V) for	:	G-2024-
the Period of June 1, 2025 through	:	
May 31, 2029	:	

_____

DIRECT TESTIMONY
OF
STAN C. FARYNIARZ

_____

UGI ELECTRIC STATEMENT NO. 2

Dated: May 31, 2024

I. Introduction

Q. Please state your name and address.

A. My name is Stan C. Faryniarz. My business address is 370 Main Street, Suite 325, Worcester, MA 01608.

Q. By whom are you employed, and in what capacity?

A. I am employed by Daymark Energy Advisors as a Principal Consultant and Practice Area Lead.

Q. Please briefly describe your responsibilities in your current capacity.

A. My primary responsibilities include supporting client projects with advisory services, insight, analysis, and guidance pertaining to a suite of topics. These topics include wholesale and retail energy and renewable energy credit procurement, strategic analysis and design of clean energy resources and associated programs, rate and tariff review and audit, rate design, analysis of both state and federal regulatory policy and ensuing proposals, transmission development strategy, and providing guidance on Independent System Operation process and rules. As stated previously, I am also a practice area lead for the Procurements & Portfolios, and Rates & Pricing areas, which includes additional business-related functions such as budget development, client forecasting and acquisition, and sales support including RFP submission development.

Q. What is your educational background and prior professional experience?

A. Please see my resume that is attached as UGI Electric Exhibit SCF-1.

Q. Have you previously testified as a witness before the Pennsylvania Public Utility Commission ("Commission" or "PUC")?

A. Yes, please see UGI Electric Exhibit SCF-1 for a listing of the proceedings in which I have been a witness.

Q. What topics will you address in your direct testimony?

A. The purpose of my testimony is to demonstrate that UGI Electric's proposed Default Service Plan V ("DSP V") will: (1) acquire electric generation supplies at the least cost to customers over time in accordance with 66 Pa. C.S. § 2807(e)(3.3)(ii) and 52 Pa. Code § 54.185(d); (2) utilize a prudent mix of resources, including spot market purchases, short-term contracts, and long-term arrangements, in accordance with 66 Pa. C.S. § 2807(e)(3.2)(i)-(iii) and 52 Pa. Code § 54.186 (b)(1)(i)-(iii); and (3) use a competitive bid solicitation process in accordance with 66 Pa. C.S. § 2807(e)(3.1) and 52 Pa. Code § 54.186(b)(5).

Q. Does your direct testimony address any other regulatory obligations or topics?

A. Yes. In addition to meeting the statutory requirements set forth in regulation, my testimony will address the following:

- A description of the background and essential elements of the DSP V Plan;
- A description of the DSP V product mix, product terms, procurement approach, and other related terms;

- A description of the pro forma Request for Proposals Process and Rules ("RFP Rules") and the pro forma Master Agreement ("MA") for Default Service, Block Energy, and Alternative Energy Credits ("AECs"), which are included as exhibits to this testimony;
- Compliance with the Alternative Energy Portfolio Standards Act ("AEPS Act") and Procurement of AECs; and
- A description of the RFP process, including bidder qualifications under the RFP Rules and the Default Service MA.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the exhibits identified as UGI Electric Exhibits SCF-1 through SCF-10.

II. OVERVIEW OF HISTORIC DSP STRUCTURE AND PERFORMANCE

Q. Please describe the basic structure of UGI Electric's default supply activities.

A. The Company procures default supply for two Generation Supply Rate ("GSR") customer groups. During DSP IV, these groupings, either GSR-1 or GSR-2, were based on each customer's highest billing demand in the twelve-month period ending September 30, 2020 with those at or above 100kW being provided GSR-2 default supply and those below 100kW being provided default supply on GSR-1. This is described in the testimony of UGI Electric witness Tracy A. Hazenstab, UGI Electric Statement No. 3. GSR-1 customers have historically been supplied by a structured portfolio of products. GSR-2 customers have historically been supplied by purchases made through the PJM Interconnection LLC

("PJM") hourly spot market by UGI Electric. Modifications related to clarifying the application of GSR-1 versus GSR-2 on the basis of supply peak load impact during DSP V are discussed below and further in Ms. Hazenstab's testimony.

Q. Please describe the Company's historic approach to procurement for GSR-1 customers.

A. Historically, the Company has incorporated a mix of load-following and block supply. The Company conducts energy auctions twice per year, typically occurring in the Spring (April) and Fall (October). The products and terms reflect a layered and laddered approach, with only a portion of supply procured in each auction, with varying contract terms, resulting in an overlap of contracts to fulfill the supply obligation. In DSP IV, the Company utilized a mix of 6-, 12-, and 24-month fixed price load following full requirements ("FPFR") contracts. Supply for these FPFR contracts began in June and December.[1] Further, the Company also procured a series of one-month around-the-clock ("ATC") and peak block supply contracts. These block products were secured in 6-month groups, coinciding with the respective upcoming 6-month rate term.

Q. What was the structure of the block products in UGI Electric's portfolio in DSP IV?

A. During DSP IV, the Company implemented a 6-month procurement schedule, conducting auctions twice per year during the Spring and Fall. As explained above, the Company incorporated a mix of both block and FPFR supply contracts. The block contract load share sought to secure approximately 25% of the total default service supply mix through firm,

[1] Supply for FPFR products bid in April began in June. Supply for FPFR products bid in October began in December.

energy-only contracts ranging from 15-25MW in size. This 25% target was established as part of the settlement provisions related to DSP IV. Two specific types of block product were procured – Peak Block products and ATC Block products. The Peak Block products were established for the PJM-defined peak hours of Hour Ending 8 am through Hour Ending 11pm for non-holiday weekdays (i.e., 5x16), while ATC Block products provided supply 24 hours a day for all 7 days of the week (i.e., 7x24). The contract term lengths for the block contracts – both Peak and ATC – were for individual calendar months (i.e., 1-month); however, UGI Electric procured them for 6 consecutive months. The 6 consecutive months ran from June through November, procured in the April auctions, and December through May, procured in the October auctions. Each monthly contract included a unique price based upon the winning supplier's bid, which also held the potential for different suppliers providing block supply each month.

Q. What was the structure of the FPFR products in UGI Electric's portfolio in DSP IV?

A. For FPFR contracts, the Company issued RFPs seeking 6-, 12-, and/or 24-month supply terms. Of note, the 6-month contracts were only used at the commencement of the plan and not as part of the rolling 'steady state', which was comprised of the mix of 12- and 24-month contracts layered in throughout the majority of the DSP period. The first procurement by the Company in DSP IV included three load-following tranches for bid: (1) a 6-month FPFR tranche providing supply from June 2021 through November 2021; (2) a 12-month FPFR tranche providing supply from June 2021 through May 2022; and a (3) 24-month FPFR tranche providing supply from June 2021 through May 2023. Each tranche represented approximately 25% of the total estimated default service supply

obligation, or 75% in total, after the approximately 25% of the portfolio covered by the block contracts. It is also important to note that the load obligation for the FPFR products was also reduced to account for the approximately 264 kW of long-term Power Authority of the State of New York ("NYPA") power supply, as described later in my testimony.

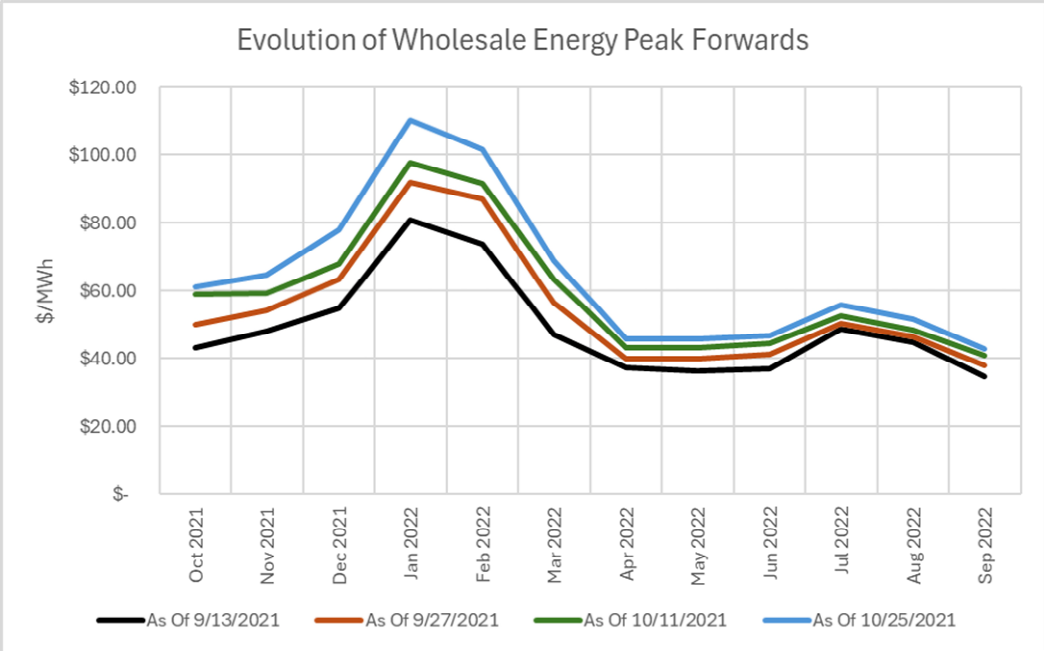
Q. Please summarize the procurement results obtained by UGI Electric in DSP IV.

A. As of the time of this filing, UGI Electric has completed 7 of the 8 total energy solicitations, with the final auction planned for October 2024. During those 7 energy solicitations, the Company received a range of bids, primarily reflecting the volatility in forward energy markets associated with the DSP IV supply period. For example, UGI Electric received bid prices between $60/MWh to $135/MWh for FPFR supply, $25/MWh to $140/MWh for ATC Block supply, and $30/MWh to $155/MWh for Peak Block supply.

Q. Were there any market events that may have impacted bid results during the DSP IV Plan term?

A. Yes. While it is difficult to determine the exact impact of a market event on supplier bids, there were a series of events that led to increased market prices, which seem to have been reflected in winning bids. The two most impactful in the wholesale energy market were the prospective U.S. natural gas price spike occurring in the Fall of 2021 and the War in Ukraine in March of 2022. The domestic natural gas price spike occurred in late September 2021, driven by a perceived shortage of natural gas storage and an expectation for a cold winter and, therefore, an increased demand on natural gas for energy and heating purposes.

As shown in the graph below, forward wholesale peak energy prices jumped in late September 2021 and continued to rise through October, when compared to the baseline forward prices September 13, 2021. Prices increased by between $16-$29 for the forward months of October 2021 through March 2022. This spike occurred at the same time as UGI Electric's October 2021 auction.



Following a mild winter in 2021/22, wholesale energy prices began to return to normal levels, with forward prices reflecting this decreased risk. However, a similar natural gas-led price spike occurred in early April 2022 as a result of the War in Ukraine. Wholesale energy forwards again reflected a concern for natural gas shortages associated with reduced liquified natural gas (LNG) supplies from Russia, driving prices up to between $20-$50/MWh depending on the month. These high prices persisted through 2022 and into early 2023. Once again, the spike occurred just prior to the UGI Electric April 2022 auction, also impacting the October 2022 auction and likely the April 2023 auction.

Q. Have the products procured in the Company's DSP IV Plan been successfully and competitively bid to meet its default service supply obligation?

A. Largely, yes. The Company saw supplier participation sufficient to meet the respective GSR-1 and GSR-2 default service supply obligations. However, starting with the April 2022 auction, UGI Electric experienced a drop in supplier participation for both the 12-month and 24-month FPFR supply terms, down from a range of between 2-5 suppliers. However, pricing for these products continued to be within the range of market expectations. In general, block product supplier participation has remained relatively strong with between 4 to 5 suppliers per auction, with only one auction, in October 2022, where supplier participation dropped steeply, rising in the subsequent auction back to 5 participants.

III. DSP V DEVELOPMENT APPROACH

Q. Please explain the approach taken by UGI Electric in the development of DSP V?

A. The Company must adhere to a series of state regulatory obligations, such as acquiring supply at the least cost to customers over time utilizing a prudent mix of products through a competitive bid solicitation process. In addition, the Company has identified two additional focused objectives: (1) to maximize supplier participation for all products by reducing risk for suppliers due to product/portfolio design where it is prudent to do so, thereby increasing competition for those products and potentially reducing costs of UGI Electric customers; and (2) to provide greater price stability over time and from DSP V into DSP VI, while lowering administrative burdens, by having less individually awarded products with more stable terms including some overlap with DSP VI.

The Company also reviewed the GSR-1 and GSR-2 default service rates to confirm they properly align with changes to the products and terms of those products being procured in DSP V. Through this review, the Company has clarified specific GSR-1 and GSR-2 default service rate applicability in order to properly address default service procurement impacts and management. Qualification will be specifically related to a review of each customer's supply peak load impact to the system, either from the system or as related to customer-generators, into the system. As with DSP IV, the Company is utilizing a 100kW threshold for this determination, with those customers with peak load impact at or above 100kW being GSR-2 default service customers and those below 100kW being GSR-1 default service customers.

Q. How did the Company evaluate the options available for inclusion in the DSP V portfolio?

A. UGI Electric sought to build a product mix, both as to product type and term of contract, that balances market reflectivity and price stability. Market reflectivity refers to how closely any given product tracks the active energy market at that point in time – typically the spot energy market. Price stability refers to the relative volatility of contract prices and the relative rate change between customer rate changes or from one price-to-compare period to the next. Increasing market reflectivity, under normal market conditions at a point in time, often provides the lowest average price; however, as seen with the spot market, it is the most volatile and can result in extremely high prices during market events. More price stable (i.e. fixed price) products reduce that volatility but may result in a higher relative premium for that stability. In short, the greater the market reflectivity, the greater

the risk of price volatility that is transferred to the customer; the greater the price stability, the greater the risk that is transferred to contracted supplier, which would almost certainly lead to a higher overall price to compensate for the risk. The Company also considered the relative size of its default service customer load and the impact that may have on risk, supplier bid pricing, and overall supplier participation. During DSP IV, the relative sizing of 12- and 24-month FPFR products were about 37 MW (PLC)[2] each tranche, or a total of approximately 112 MW out of a total PLC of 138-140 MW. This value was low, especially when compared to peer Pennsylvania EDCs, which had a tranche size of 70-100 MW,[3] or double that of UGI Electric. Notably, UGI Electric's smaller tranche size could lead to increased supplier risk premiums and lower supplier interest in the product.

Q. How does the DSP V portfolio structure seek to address the statutory requirement that it reflect a prudent mix of products?

A. UGI Electric has developed a product mix that balances market reflectivity and price stability, including FPFR contracts, ATC Block contracts, and the long-term contract through NYPA (the Allegheny Agreement). The product mix also relies on the PJM spot market to supply GSR-2 customers, and to settle volumetric differences associated with contracted FPFR contracts for the GSR-1 group. The proposed contract terms include hourly spot market, 12-month, 24-month, and long-term (defined by statute as a contract with a 4+ year term) to satisfy the regulatory obligations in the statute and develop a balanced portfolio.

[2] PLC stands for Peak Load Contribution.
[3] Examples: Total peak tranche size for PPL Electric is approximately 73MW (Residential); total peak tranche size for PECO is 63.7MW (Residential).

Q. Is UGI Electric proposing any modifications to its procurement methodology in DSP V?

A. Yes. The Company is seeking Commission approval for updates to its products, auction timing and implementation mechanics, and a series of Master Agreement updates. The Company believes that these modifications will improve the competitiveness of its auctions and provide better price stability at an overall lower cost for consumers than the Company would achieve if it continued with its current portfolio structure.

Q. Please summarize the major differences between the Commission-approved DSP IV Plan and the proposed DSP V Plan.

A. Refer to UGI Electric Exhibit SCF-2 for a table that provides the major differences between DSP IV and DSP V. In general, the Company is proposing changes to a series of areas including:

- Updates to the products – types, terms of contract, load share or MW size, and for FPFR contracts, the exclusion of non-market-based transmission service charges.

- Energy and AEPS RFP timing – widening the twice-per-year auction windows to between January and March, and July and September.

- Energy and AEPS RFP requirements – implementing Bid Assurance Collateral requirements, implementing a rule for FPFR contracts that no supplier may win more than one tranche, establishing provisions for Capacity Pricing for FPFR Bidders when a PJM capacity price is either incomplete or unavailable at the time of auction, providing terms for how UGI Electric may reduce or eliminate a block product procurement if default service load decreases, proposing that GSR assignment will be a function of each customer's supply peak load impact (including net-metering customer-generator peak impact on supply into the system).

- Contingency Plans – implementing Contingency Plans for both energy and AEPS RFPs in the event of a failed bid for one or more products.

- Contracts – implementing Performance Assurance Collateral requirements for FPFR and Block suppliers.

- AEPS RFP – moving forward the bid date to align with energy auctions and adjusting the methodology to calculate AECs to be procured.

IV. PROPOSED DSP V PROCURMENT STRATEGY FOR GSR-1

Q. Please describe the procurement methodology UGI Electric is proposing for the GSR-1 supplies during the term of DSP V.

A. In DSP V, the Company will continue to utilize a sealed-bid auction approach as it did in DSP IV. Additionally, as described below, the Company is also seeking to implement a series of updates to improve supplier participation, competition, and overall supplier diversity. In doing so, UGI Electric believes it will provide a more reliable competitive product and achieve price benefits for UGI Electric default service customers.

Q. How does the Company propose to improve supplier diversity?

A. As a component of the energy RFP, UGI Electric is implementing an FPFR tranche cap. In effect, this means that a supplier is only able to win a single tranche of the 12-month FPFR supply – approximately 40% of the total UGI Electric supply portfolio for GSR-1 after the ATC Block share is applied. This does not apply to ATC Block; therefore, a supplier may in theory win one tranche of FPFR and all 20 MW of Block supply. The intent of the FPFR tranche cap is to reduce the risk exposure to customers in the event of a supplier default. Additionally, as discussed in Section VII below, the Company is also seeking to implement improved Bid and Performance Assurance Collateral requirements. Similar to the FPFR

tranche limitation, the improved collateral requirements are intended to reduce the cost to customers in the event of supplier default and to reduce the risk of a default occurring.

Q. Please explain the proposed term of the DSP V Plan.

A. UGI Electric intends to maintain the 4-year DSP Program term that was used for DSP IV. The DSP V supply term will run from June 1, 2025, through May 31, 2029. Given the nature of the layered and laddered product mix, a portion of the 12-month FPFR and 24-month ATC Block supply will extend into the next default service plan term (DSP VI) to provide improved continuity and stability between energy plans. This approach aligns with what the Company has implemented in DSP IV, with a portion of the 12-month FPFR supply extending from DSP IV into DSP V. While the DSP V into DSP VI is of a greater percentage – 25% in DSP IV into DSP V versus approximately 50% from DSP V into DSP IV – both layered and laddered approaches provide valuable continuity between default service energy plans.

Q. Please describe how UGI Electric proposes to commence the DSP V procurements.

A. At the start of DSP V, the Company is seeking to procure a significant protion of its supply needs, as there is limited overlap in products from DSP IV.[4] In Solicitation 1,[5] UGI Electric will procure a 6-month FPFR contract for 25% of supply and a 12-month FPFR contract for the remaining 50%, as well as one 10 MW 24-month ATC Block product. It is important to note that the FPFR load share is applied after the 10 MW of block and 264 kW supply

[4] Limited contract overlap exists between DSP IV into DSP V. This includes a 25% supply from 12-month FPFR and approximately 264kW from the long-term Allegheny Agreement.
[5] Solicitation 1 will be broken up into two months to diversify procurement timing and concentration risk.

from the Allegheny Agreement is applied – with each 10 MW of block representing an approximate 12% load share for GSR-1 related product procurement. Thus, the equal break between 6 and 12-month terms will equate to approximately 44% of total load each tranche (aggregate total of approximately 88%). To mitigate a market event or point-in-time price spike, UGI Electric will conduct two auctions – one in January or February and the second in February or March, depending on the timing of the Commission's approval of the Company's DSP V. The first auction will bid the 12-month FPFR product and 24-month ATC Block product, while the second auction will bid the 6-month FPFR product. By taking this approach, roughly 55% of supply is bid in the first auction and 45% in the second – diversifying when the products are bid. The timing of auctions after Solicitation 1 are described in Section VII of my testimony, below.

Q. Is the Company seeking to modify the steady state procurement approach in DSP V?

A. Yes. After the hard start, UGI Electric proposes that its steady state portfolio for DSP V include a mix of 24-month ATC Block, laddered 12-month FPFR, and the continued inclusion of the long-term Allegheny Agreement. Please refer to UGI Electric Exhibit SCF-3 which provides an overview of the products, term, and timing of solicitation.

Q. What block energy products is UGI Electric proposing to use in DSP V?

A. The Company proposes to use 24-month ATC Block products. It will begin with a 10 MW 24-month ATC Block in Solicitation 1 and grow to 20 MW following a successful solicitation in Solicitation 3 (i.e., the third auction). Procurement for 10 MW of ATC Block will continue annually, with 10 MW rolling off and a new 10 MW rolling on.

Q. Why is the Company proposing to change the procurement approach for block energy product supply as a component of the product mix?

A. Under the DSP IV Plan, UGI Electric procured a mix of ATC and Peak Block energy products. Though procuring for a 6-month period of time, each month was bid individually (e.g., June to November period bid June, separate from July, separate from August, etc.). The MW size of the blocks also varied in an attempt to maintain a 25% load share for block while accommodating seasonality. Therefore, ATC and Peak Blocks ranged between 10-25 MW each or, in total, between 20-35 MW. Supplier participation substantially decreased for the FPFR contract, which the Company believes is a result, in part, of supply risk due to variable block sizing which changed throughout the course of the 12 and 24-month FPFR contracts under DSP IV. There is also a risk that, given the small overall size of UGI Electric's default service supply – with a PLC ranging from approximately 138-142 MW – the load share of block supply during some months was too great to secure attractive FPFR bids, a higher-margin product for bidders.

Q. How does the Company's proposal address these concerns?

A. To reduce this risk, the Company will expand the FPFR load share, improve the solicitation for FPFR, and continue to leverage the benefits obtained from block supply contracts. UGI Electric is seeking to adjust its block products to eliminate the variability and extend the term of its block products while simultaneously reducing the number of FPFR product types to create a more transparent, less risky suite of default service products. The Company's proposal includes 20 MW of ATC Block in two 10 MW 24-month contracts

that will be layered so that a new block product is added annually. The 24-month block products will replace the 24-month FPFR currently implemented in DSP IV. This will provide a stable block supply quantity – 20 MW – for which FPFR suppliers can accurately account, thereby reducing load variance risk in the FPFR product. Shrinking the block size but lengthening the term will increase the FPFR tranche size to approximately 60 MW (from 40 MW in DSP IV), while increasing the total value proposal of the block product for block bidders. Utilizing a 24-month ATC Block is also expected to reduce supplier risk premiums typically seen attached to longer-term FPFR products. It will also reduce the administrative burden associated with the Company's current approach. The longer-term block contract is also more appealing to most suppliers because it provides an increased supply obligation they can layer into their overall portfolio, and scaled up margin.

Q. What other benefits are produced by the 24-month layered block structure?

A. Implementing 24-month ATC Block products takes advantage of blending rates between different seasons, reduces the impact of potential market events that could arise throughout the contract term, and provides some level of rate stability by procuring a portion of supply over a longer-term. Further solidifying the default service product mix, UGI Electric will incorporate layered and laddered 12-month FPFR contracts, leading to increased tranche size and, it is hoped, decreased load variance risk and price volatility in order to improve supplier participation and reduce risk premiums.

Q. Is the Company proposing any other modifications to the FPFR products in DSP V?

A. Yes. Beyond adjustments to the product mix and terms, the Company is also proposing to implement contract-related terms to address market and more generalized pricing risk associated with PJM capacity pricing and non-market-based transmission service ("NMB") charges.

Q. Please describe the concerns regarding PJM capacity pricing.

A. In recent years, PJM has undertaken changes in its capacity market that are still underway. These changes have resulted in delays in final capacity prices being issued. Historically, PJM capacity prices have been preliminarily issued three years in advance and final capacity prices approximately a year prior. However, that process has slowed in recent years and, in some instances, only a single price is issued mere months prior to a contract's supply start. This creates risk for FPFR suppliers, not knowing what the future capacity market price will be and, in turn, either creates a higher risk premium on bids or leads suppliers to decline bidding on FPFR supply entirely. To address this, UGI Electric is proposing to provide guidance and relief to suppliers if and only if capacity prices are not finalized or are not available. Specifically, if the term of the FPFR contract overlaps with a future capacity period for which PJM has not yet issued a final capacity price or for which no capacity price yet exists, UGI Electric proposes to instruct suppliers to utilize the most recent capacity price in preparing their bids.[6] When billed, the Company will compensate suppliers for the difference between the capacity price upon which bids are based, and the actual capacity price. If the delta is negative, meaning the price used is greater than the

[6] If no price is available for the future capacity period, the prior capacity year's price would be used. If a partial but incomplete capacity price is available – for example, the Base Residual Auction ("BRA") is complete, but no incremental auction is completed, or PJM has not issued a final rate – the BRA or the best price available for that period would be used.

actual price, suppliers will credit UGI Electric. While the Company does not foresee capacity prices continuing to run into the same timing issues as in the recent past, with PJM diligently working to implement their new framework, this guidance will aid in reducing supplier risk, improving bids, and likely improving supplier participation.

Q. Please describe the NMB costs.

A. Similar to the PJM capacity costs, NMB charges provide an additional risk to suppliers. NMBs are effectively passthrough transmission costs; however, the issue arises in the timing of these prices – typically released in April or May, just prior to their effective start date in June. Given the timing of these charges, suppliers providing FPFR service have no time to incorporate their costs into the bid proposals, resulting in increased bid premiums or non-participation. UGI Electric is proposing to assume responsibility for select charges that were previously borne by FPFR suppliers, eliminating the risk premia associated with future unknown charges. These include charges such as Network Integration Transmission Service Charges, Non-firm Point-to-Point Transmission Service Charges, Regional Transmission Enhancement Planning ("RTEP") Charges, and Generation Deactivation.

Q. Why is the Company proposing these changes?

A. Taken collectively, these changes aim to remove elements that introduce risk for suppliers where appropriate and practical, which is intended to increase supplier participation and reduce associated product risk premiums without needlessly increasing risks to customers. Most other EDCs in Pennsylvania remove these elements from FPFR contract

specifications, so adopting these changes should improve the competitiveness of UGI Electric's FPFR products.

Q. Please describe the Allegheny Agreement and its role in DSP V.

A. A small portion of the Company's default service supplies for DSP V will continue to be acquired through the long-term arrangement between UGI Electric and the Allegheny Electric Cooperative, Inc. ("Allegheny") as was done in DSP IV. A copy of this agreement is provided with my testimony as UGI Electric Exhibit SCF-4. Allegheny purchases generation from NYPA in bulk and resells it to various Pennsylvania counterparties, including UGI Electric. During each year of DSP V, Allegheny will provide UGI Electric with an allocated share of hydroelectric power generated in New York and obtained from NYPA. UGI Electric's allocated share is currently set at 2.6409% of the total amount that Allegheny purchases from NYPA and distributes to the various Pennsylvania counterparties under the Agreement. Currently, UGI Electric estimates that it will purchase 264 kW or 2,402 MWh of this generation for this Plan year. NYPA will likely revise this percentage during the term of DSP V. Pursuant to the terms of the Agreement between UGI Electric and Allegheny, the Company will incorporate revised percentages set by NYPA. Historically, the updates and revisions have been limited in nature. These procurements will continue to be included as a generation supply source in the Company's DSP V and will be recovered through the Company's GSR-1 rate.

Q. Will the Company's GSR-1 procurement strategy include any spot market purchases?

A. Yes. In addition to the products already discussed, the GSR-1 portfolio will include transactions related to spot market purchases and sales when necessary. More specifically, the Company utilizes a load forecasting methodology to determine the default service load that it must schedule on an hourly day-ahead basis through PJM for GSR-1 and GSR-2 customers. This forecast is based upon best available customer usage data, customer profiling, expected weather, and other statistics such as customer shopping. Data is aggregated and divided by default service supplier contract obligations – both block and FPFR – before being scheduled to the market through PJM. Actual customer usage will of course differ from this forecast, with the difference then being settled through the real-time market in the form of spot purchases or sales. UGI Electric proposes to reconcile variances between actual load consumption and scheduled electric deliveries in DSP V through spot market settlement. This is the same method that was utilized for DSP IV to reconcile scheduling variances.

Q. Please describe the anticipated spot market activity.

A. The Company currently anticipates implementing an identical process to that which was used during DSP IV to manage spot market transactions. Spot market purchases will occur in the real-time market administered by PJM on an hourly basis when actual loads differ from the summation of the Company's load-following and block purchase projections. The Company will be invoiced for these spot transactions on its monthly PJM bills. If the Company's actual hourly load is greater than its projected hourly load, then the surplus will be satisfied through spot market purchases for that hour. The resulting costs or credits will

be applied to the appropriate parties based upon cost causation principles. As such, the resulting charge or credit amounts will flow through to customers appropriately.

Q. What other energy products will be included in the Company's GSR-1 procurement strategy?

A. During the term of DSP V, the Company will continue purchasing generation from customer-owned generation resources, also referred to as net metering resources, in its service territory. I will address these procurements in greater detail in Section VI of my testimony.

Q. Is the Company's proposed procurement methodology for GSR-1 customers designed to acquire default supplies at least cost over time?

A. Yes. The Company's proposed DSP V is designed to obtain competitive pricing offers from wholesale suppliers for its portfolio of load-following and block supplies. The Company will choose the bid responses that have the lowest cost for generation. Consequently, these purchases will provide the GSR-1 customers with reliable supply that is the least cost over time.

V. PROPOSED DSP V PROCURMENT STRATEGY FOR GSR-2

Q. What is the strategy for procuring default service supplies for GSR-2 customers in DSP V?

A. To meet the GSR-2 load requirements during DSP V, the Company will continue to use the hourly procurement methodology that was used in DSP IV. Accordingly, through DSP V, the Company will acquire default service energy for these customers through PJM's

real-time hourly spot market. In addition to energy purchases, the Company will be responsible for acquiring any necessary capacity, transmission to UGI Electric's system, ancillary services, congestion management services, AEPS credits, applicable net metering excess generation purchases and such other services or products as necessary to provide default service to the Company's GSR-2 customers.

Q. Why is it appropriate to charge GSR-2 customers real-time pricing?

A. Customers in the GSR-2 rate group include medium and large commercial and industrial customers. These customers are typically more sophisticated in their business operations and energy use, and include customers utilizing energy managers. Most of these customers access the retail energy market by shopping their requirements with third party suppliers, and are therefore regularly participating in, or assessing participation in, the retail market. They also frequently adjust their energy use in line with market conditions. As a result, utilizing real-time pricing is the most appropriate solution, because it limits the risk premiums these customers pay for what is typically a short-time on the GSR-2 rate before accessing the retail electric generation market. GSR-2 will also include customer-generators having a supply peak load impact at or above 100 kW. These customers likewise can impart material risk for default service supply procurement.

In total, GSR-2 customers represent significant volatility and risk for any supplier that would seek to provide UGI with GSR-2 supply. This could result in high risk premiums or little to no supplier participation. In fact, this risk – higher premiums and the potential for customer cross-subsidization – is the foundation for the Commission's determination

that EDCs implement a demand split for commercial and industrial customers through the PA PUC Retail Market Investigation.

VI. ANTICIPATED LOAD IMPACTS TO DEFAULT SERVICE DURING DSP V

Q. Why is it important for UGI Electric to anticipate potential sources of substantial change in the amount of customer load to be served during DSP V, and identify those risk elements as part of the RFP process?

A. As described previously, UGI Electric's default service load is small, especially compared to other Pennsylvania EDCs. For example, the total PLC for UGI Electric's GSR-1 customer group, inclusive of residential and smaller commercial and industrial customers in 2023 ranged from 138-142MW. PPL Electric's residential PLC alone was over 1,800MW. Any substantive adjustment to the Company's default service load, especially decreasing the load, risks decreasing supplier interest in FPFR products, increasing supply premiums for FPFR products, and undermining the overall default service program.

Q. What known sources of potential impact has the Company identified?

A. The Company has identified two areas that could impact the DSP V portfolio's operation and cost, particularly with regard to the GSR-1 customers: (1) levels of retail choice participation (customer shopping); and (2) impacts from the level of net metering customer-generation. In this section of my testimony, I will describe these concerns, how they might impact the GSR-1 portfolio, and the Company's proposal for addressing these concerns.

Q. Please describe the impact of retail choice on UGI Electric's DSP IV.

A. Throughout DSP III and DSP IV, retail choice has had a limited impact on the DSP and the associated customer load. Customer shopping levels for the GSR-1 rate schedule have fluctuated between 5-7%. Customer shopping levels for the GSR-2 rate schedule have been much higher, with nearly 50% shopping. Given the stability of GSR-1 customer shopping, the risk associated with shopping to-date has stabilized for wholesale suppliers supplying FPFR contracts in particular.

Q. What role do potential changes in the level of retail choice participation play in the development of DSP V?

A. The greatest impact and risk associated with retail choice for DSP V is the erosion of load, thereby decreasing the size of the load served by FPFR supply contracts and/or causing an over-procurement of supply due to the use of block contracts. A substantive decrease in load, or material change in the chance of such a decrease, could result in higher costs to default service customers due to an increase in supplier risk premia, a lack of suppliers willing to undertake such risk and participate in auctions, especially for FPFR products, or from the over-procurement of ATC contracts, which could result in additional costs to customers associated with the spot market sale of excess energy. These risks are not easily identified or accounted for in the planning process.

Q. Is the Company proposing any changes in DSP V concerning the impact of the level of retail shopping on UGI Electric's ability to secure adequate default service supply?

A. Yes. Given the risk summarized above, the Company is proposing to implement a process whereby the Company, with support from the Auction Manager, will evaluate the level of UGI Electric customer shopping prior to opening an energy auction for the ATC Block Product. If shopping has grown to a point that it has eroded or is likely to erode FPFR tranche size (MW) during the planning horizon, UGI Electric will reduce the amount of 24-month ATC Block by not procuring the full term of the ATC Block in the next auction. Instead, the Company will procure a 6-month 10MW ATC Block contract to ensure there is *de minimus* impact on currently effective FPFR contracts through the remainder of their term. Suppliers bidding on the FPFR product procured at the same time as the 6-month 10MW ATC Block product will be notified of the reduction in ATC Block supply 6-months into the term of their contract, thereby increasing their load obligations. Not procuring the extended 24-month block supply will increase FPFR PLCs and associated load to a higher, more stable level, in an attempt to minimize supplier risk and thereby reduce premiums to customers.

Q. If implemented and the ATC Block is reduced, will the change add additional risk that was not otherwise present to suppliers?

A. No. To be clear, this process would only be implemented if FPFR load dropped to a level that could result in higher risk premiums or reduced supplier participation. This change is in fact an attempt to reduce risk and improve competition. Further, any change would have no impact on contracts already in effect. Any FPFR supplier bidding on a future term would

be provided information on the reduction in the ATC Block to appropriately incorporate the change into their bid analysis and resulting bid price.

Q. If the ATC Block products are reduced due to high customer shopping, will the Company maintain that structure going forward?

A. No, not necessarily. Throughout DSP V, UGI Electric and the Auction Manager will continue to review the level of UGI Electric customer shopping prior to opening an energy auction. If shopping has decreased and is expected to remain at lower levels, the Company may choose to reintroduce additional ATC Block products through re-solicitation of up to 20MW of ATC Block. Similar to the step-down provisions above, the Company would delay the implementation of the new ATC Block to occur after any currently effective FPFR contracts conclude so as not to impact those supply arrangements. Further, the Company would notify bidders of the ATC Block supply change going forward for all subsequent auctions.

Q. Please describe net metering customer participation in UGI Electric's service territory during the DSP IV Plan period.

A. Net metering participation in UGI Electric's territory has been, and currently is, relatively low. As of May 2023, the Company had less than 200 customers participating in its net metering program. Exported generation from these customers has likewise been relatively low, resulting in an average of 215,710 kWh of excess customer-generation on UGI Electric's system annually over the last three years that was credited through the net metering program. While the Company had some growth in net metering participation

since DSP III, the total growth during DSP IV did not meaningfully impact the Company's default service load and procurement activities.

Q. Historically, how has UGI Electric structured its default service portfolio to address the possibility of an increase in net metering?

A. Due to the *de minimus* nature of the anticipated impact of net metering on the total load to be served through the default service portfolio, the Company did not specifically plan for or seek to make adjustments based upon the way that net metering would impact its procurement activities or portfolio. Suppliers were informed of the inclusion of net metering customers such that they may assess associated risk; however, the impact was small.

Q. What is the anticipated impact of net metering on total system load during DSP V?

A. UGI Electric currently has 30 new applications for net metering systems to be installed in the Company's service territory within the next 3 years. Of these 30, 16 installations will have supply peak load impacts under 100 kW that will impact GSR-1, and 14 will have supply peak load impacts greater than 100kW that impact GSR-2. The facilities impacting GSR-1 will provide up to 186kW of generation, whereas the 14 facilities classified as GSR-2 will provide up to 22 MW of generation. All of the inquiries regarding GSR-2 customer-generation facilities have been over the past twelve months. Thus, based on the inquiries received to date, UGI Electric may add as much as 12,000-22,000 kilowatts (12-22 MW) of nameplate capacity in large-scale customer-generation in the next three years in particular. Excess power production from these customer-generators could range between 35,000,000 to 45,000,000 kWh annually. This would result in upward of a 150 to 200 times

or more increase in UGI Electric purchases of exported net metered energy over the highest historical activity from existing customer-generation. I note that an anticipated 22 MW of total generation would represent approximately 6% of UGI Electric's total default service load.

Q. What considerations has the Company made to address the anticipated impact of net metering on total system load during DSP V?

A. As discussed above, the Company's DSP V proposal evaluates the appropriate default service classification based on the impact a customer will have on supply activities. The Company recognizes that there are appropriate reasons to establish thresholds for designation of customers having the potential for larger impacts to default service load in relation to customers with smaller impacts. Accordingly, larger net metering customer-generators, those with material capability to impact default service load (i.e., those also having supply peak load impacts greater than or equal to 100kW; albeit in form of generation placed on the UGI Electric system) are differentiated from smaller-impact net metering customer-generators that can be reasonably assessed and contained within GSR-1 procurement plans. Accordingly, DSP V adopts these criteria assessing supply peak load impact to classify customers as either GSR-1 or GSR-2 for purposes of default service supply planning. While the final total impact of these net metering systems is unclear, the Company must position its default supply portfolio to accommodate impacts in net metering in a way that minimizes the impact to default service rates, consistent with the requirements of 66 Pa. C.S. § 2807(e)(7).

Q. How will GSR-1 and GSR-2 be impacted by net metering during DSP V?

A. With the recognition of the supply peak load impact that customers have on the Company's default service load, risk evaluation is enhanced. Accordingly, where a net metering customer's supply peak load impact is assessed to be less than 100 kW, that customer will be included in the GSR-1 group. Where a net metering customer's supply peak load impact is greater than or equal to 100 kW, that customer will be assigned to GSR-2. The Company's GSR-1 procurement portfolio will accommodate and address the potential fluctuation in participating GSR-1 net metering through adjustments in the total load covered by the FPFR contracts, and this will be communicated to the FPFR suppliers through the RFP process for their consideration in bid development. GSR-2 net metering will be accommodated via reduction in the total PJM spot market purchases that are made for GSR-2. Should the total net metering generation exceed GSR-2 demand at any point in time, excess generation will be sold back to PJM. The related tariff modifications necessary to accommodate net metering customer exports impacting GSR-1 and GSR-2 loads and rates are explained in Ms. Hazenstab's testimony, UGI Electric Statement No. 3.

Q. How does this treatment of net metering address the concerns associated with the impact on the Company's default service supply obligation during DSP V?

A. The assignment of net metering customers with supply peak load impacts of 100kW or greater to GSR-2 are intended to group similar commercial and industrial customers having similar grid impacts. Large net metering facilities have substantial grid impacts somewhat akin to those associated with large commercial and industrial customers that shop for power supply. As discussed previously, GSR-2 customers have a higher shopping level as

compared to GSR-1 customers, and thus more variable impacts on the default service supply portfolio. While net metering is not shopping, large net metering customers have a comparable impact and may choose to move to wholesale market participation. Therefore, the assignment of large net metering customers to the GSR-2 rate group is logical and reasonable. This assignment will appropriately ensure GSR-1 is not negatively impacted.

Q. Will any current UGI Electric net metering customers be impacted by the Company's proposed criteria utilized to differentiate GSR-1 from GSR-2 default service customers?

A. No, there are no current net metering customers that will be impacted by this change. The impact of the change is prospective in nature only.

Q. Is the Company proposing any additional changes related to the impact of net metering on GSR-1 customers?

A. Yes, however the change is a continuation of the process already explained above concerning shopping and adjustments to the ATC Block. Should the number of customers and amount of supply from those net metering customers that would remain on GSR-1 increase to such a level that FPFR supply is eroded, the Company would reduce the amount of ATC Block contracts to maintain FPFR tranche sizes. The process for the reduction would mirror the process previously described. While this is likely not necessary at this time given the low number of and overall exports from small-scale net metering installations, this option would provide the Company with the flexibility needed to

maintain FPFR tranches and help to reduce the potential increase in bid premiums attending eroded supply obligations.

VII. PROPOSED PROCUREMENT SCHEDULE AND BID REQUIREMENTS

Q. What procurement schedule has the Company used historically for GSR-1 supply?

A. Currently DSP IV energy auctions are held twice per year, once in April and again in October. Products secured in April and October are for supply that starts in June and December, respectively, with approximately 1.5 months between purchases to the supply term. While UGI Electric has successfully held energy auctions under this schedule, the Company has found two major challenges: (1) auctions have historically fallen at or around the same time as peer EDCs which results in a "competition" for supplier participation, and (2) there is little or no time to hold contingency bids should a failed product bid occur. The short window from contract execution to the supply obligation also provides a narrow timeframe for suppliers to fully hedge their products after the supply award, which could result in a higher price premium. Lastly, as previously noted, UGI Electric has also experienced instances where a market event led to price increases. While the Company could not have foreseen these events occurring, the just-in-time nature of the auctions resulted in little flexibility to account for or accommodate a market event.

Q. What procurement schedule does the Company propose to implement for GSR-1 supply in DSP V?

A. The proposed DSP V schedule will still hold energy auctions twice per year; however, the Company is seeking to incorporate a range of months when an auction can be held, moving

from a one-month to a three-month window. Specifically, UGI Electric is proposing to hold its first annual auction between January and March, and the second auction between July and September. Making this change will enable the Company to evaluate when peers are going to market to avoid coincident auctions, which can erode the number of suppliers participating in UGI Electric auctions. Further, in the event of a temporary market event that could negatively impact supplier participation or the wholesale energy market at large, an auction could be delayed, allowing the market to settle in response. Finally, in the event of a failed product bid, there is adequate time to conduct a contingency bid prior to supply start.

Q. Who will implement these power supply RFPs?

A. UGI Electric intends to employ an Auction Manager to administer the Default Service Auctions – both energy and AEC. As described in the testimony of UGI Electric witness Jesse Tyahla, UGI Electric Statement No. 1, the Company plans to undertake a competitive RFP process to secure an Auction Manager that will also function as an independent market monitor and support UGI Electric's power supply auctions.

Q. What market participants will be solicited in the auctions?

A. Both Energy and AEPS RFPs will be issued publicly, seeking to solicit bid-offers from wholesale suppliers and, for the AEPS RFP, offers from Brokers and Aggregators as well. Any supplier that has already executed a master Edison Electric Institute ("EEI") agreement with UGI Electric, as updated for DSP V changes, or expresses interest in

participating in the bid rounds will be eligible to participate in the auctions following qualification.

Q. What steps will the Company take to improve competition in the auctions?

A. As discussed previously, UGI Electric has recognized that supplier participation for some products has diminished – especially in recent solicitations. In addition to implementing the changes discussed above, which will reduce risk for suppliers where appropriate, increase the tranche size, and avoid auctions that coincide with other Pennsylvania EDCs, UGI Electric and its Auction Manager will engage in renewed efforts to encourage increased supplier participation. Prior to opening each auction, UGI Electric and the Auction Manager will perform active outreach to any supplier that expressed interest in participating in the default service bidding process in DSP IV and DSP V. UGI Electric will also seek to identify suppliers that have not participated in the auction process for UGI Electric but are active in other EDC auctions to solicit their interest in participating in the UGI Electric default service auctions going forward. The intent of this is to expand the supplier pool. The Auction Manager will also conduct outreach to suppliers to determine what media they use to obtain information about these market opportunities. This intelligence will serve UGI Electric and the Auction Manager to advertise upcoming energy and AEC auctions.

Q. What procurement method will be employed by UGI Electric in DSP V?

A. The Company is seeking to maintain the use of a sealed-bid auction process in DSP V. Under this process, prospective suppliers bid what equates to a ‘best and final offer’ for

each product for which they are qualified to bid. Bids will be confidential and not shared with any competitors or other parties outside of the Company and the Commission. The bids received are ranked and the lowest bid is selected, subject to bidders meeting technical requirements and subsequent Commission approval.

Q. What technical requirements will UGI Electric adopt for its DSP V bids?

A. The RFPs, provided in UGI Electric Exhibits SCF-5 and SCF-6, describe the qualification requirements for a supplier to be eligible to participate in an auction. In summary, a supplier must provide:

- Documentation demonstrating their good standing and compliance with PJM's tariff;
- A PJM operating agreement;
- A PJM reliability agreement;
- A partially executed EEI Agreement (if not already completed); and
- Bid Assurance Collateral in the amount required for the products in which the bidder intends to bid.

Additionally, Bidders seeking to bid on the 6- and 12-month FPFR product are limited to a single tranche or only 50% of the default service load. This limitation does not apply to the ATC Block products, for which there are no such limitations on a bidder's ability to secure some or all of those contracts. Copies of the EEI Agreement and RFP Instructions to be used in DSP V are provided as UGI Electric Exhibit SCF-7 my testimony.

Q. What will the Company seek to obtain from bidders?

A. The FPFR RFPs for DSP V will seek fixed-price load-following bids for each tranche. The block RFPs will seek fixed-price bids for the specified block.

Q. How will the Company notify the Commission and winning bidders about the bid results?

A. During DSP IV, the Company provided bid results to the Commission on the same business day that the auction occurred. Thereafter, the Commission was provided one business day to review the bid responses and approve or disapprove the Company moving forward to fully execute the confirmations. As part of the Company's outreach to bidders and prospective bidders during DSP IV to determine methods by which the Company might enhance bidder participation and pricing, bidders expressed concern regarding the two-day 'hold-open' period between bid submission and bid approval as an element that can influence bidder participation and pricing, in particular during volatile market periods. Thus, while the Company will follow the same timelines during DSP V as those used during DSP IV, UGI Electric will endeavor to work with the Commission to identify opportunities to reduce the overall time between bid submission and bid award, if possible. Tighter hold-open windows can increase participation, lower supplier pricing premia associated with holding bids open for extended periods and improve the overall process. Near the end of the award process, as the Commission approves of the winning bid responses, the Company will execute transaction confirmations with the winning suppliers. UGI Electric believes this proposed timeline is consistent with the timeline used by other EDCs.

Q. How will the Company obtain supplies for GSR-2 during DSP V?

A. As described previously, for DSP V, the Company is not proposing to modify how it obtains supply for GSR-2 from the approach used in DSP IV. Therefore, UGI Electric will satisfy its GSR-2 default service requirements by making hourly purchases of energy in the PJM spot market. When GSR-2 customers consume power each hour, PJM will settle with the Company for a corresponding amount of electricity supplied through the Real Time hourly market. All additional services such as capacity, transmission, ancillary services, and AECs will be acquired by UGI Electric. No additional RFP activity is required.

Q. Does UGI Electric's DSP IV Plan currently require bid or performance assurance collateral as a component of the auction process or ongoing contractual obligation?

A. At this time, it does not.

Q. Please describe the Company's proposal to require Bid Assurance Collateral in DSP V.

A. UGI Electric is proposing to incorporate a fixed fee Bid Assurance Collateral amount based upon the product type. For both FPFR and block contracts, prospective bidders will be required to provide $75,000 to qualify to participate in the auction. If a prospective bidder sought to bid on both FPFR and Block products in a single auction, the combined Bid Assurance Collateral amount provided to UGI Electric would be $150,000. Collateral can be in the form of cash or a qualified bank letter of credit. If cash is provided, the Company will not compensate suppliers for interest accrued. The Bid Assurance Collateral provided

by participating suppliers will be returned either: (1) immediately following Commission approval of the auction results, for all suppliers not selected, or (2) immediately following Commission approval of the auction results and after selected suppliers have fully executed all agreements. UGI Electric will not require prospective suppliers to provide Bid Assurance Collateral for AEPS RFPs, because the risk exposure is low, the pricing is less susceptible to sudden and significant market volatility, and the Company has a Contingency Plan in place that could be used to secure the needed AECs in the event of a supplier default.

Q. Why is the Company proposing to add Bid Assurance Collateral in DSP V.

A. Bid Assurance Collateral is a means to protect UGI Electric and its default service customers from an instance where a supplier fails, for any reason, to execute a contract after being selected in a competitive auction. This collateral binds the supplier to their bid, helping to reduce the risk of a supplier backing out of an agreement. Further, should a supplier choose to back-out even with the Bid Assurance Collateral provided, UGI Electric can use those monies to reduce the cost to rebid the product and offset some or all of the cost of rising energy prices, if such prices were to increase. Bid Assurance Collateral is not intended to eliminate all risk of a supplier failure to execute an agreement, or fully offset potential price increases until the product is rebid. Instead, it is a cost and risk mitigation measure. The Company does not believe the addition of Bid Assurance Collateral will negatively impact supplier participation levels during DSP V, but if that should arise as a concern, the Company will evaluate adjustments to the level of collateral required.

Q. Please describe the Company's proposal concerning Performance Assurance Collateral in DSP V.

A. UGI Electric is proposing to implement a Performance Assurance requirement in the form of a fixed fee amount. The proposed FPFR Performance Assurance would take the form of a fixed fee of $175,000 and the similar Block fixed fee would be $100,000. All such collateral will be held for the full term of the contract. Collateral can be provided by the supplier in the form of cash or a qualified banking institution Letter of Credit and, upon conclusion of the contract, will be returned to the supplier. If the supplier provides Performance Assurance Collateral in the form of cash, upon return of the collateral UGI Electric will also provide accrued interest based upon the Federal Overnight Repurchase Rate. UGI Electric will not require suppliers to provide Performance Assurance Collateral for AEC contracts, as the window between the executed contract and transfer of AECs is very short with a low risk of default. In the event of a supplier default, the Company's proposed Contingency Plans will take effect to secure the needed AECs.

Q. Why is the Company proposing to add Performance Assurance Collateral in DSP V?

A. Performance Assurance Collateral is intended to serve three major roles: (1) reduce the likelihood of a supplier defaulting on a contract due to market conditions; (2) to offset the costs of another auction to rebid the product in the event of a supplier default; and (3) to provide some financial buffer for customers should market prices have increased over the term of the contract in the event of a supplier default. UGI Electric believes that the use of fixed fee Performance Assurance will provide risk mitigation for the Company and its customers while also aligning with similar practices by other EDCs in the state.

VIII. CONTINGENCY PLANS FOR ENERGY AUCTIONS

Q. Why are Contingency Plans included in the Company's DSP V Plan?

A. Contingency Plans are included in the Company's DSP V in the event that the Company cannot secure wholesale generation supplies sufficient to meet its default service obligation due to a failed energy auction. There are three potential reasons for a failed auction: (1) the Company receives no bids for a given product; (2) the Company fails to have a sufficiently competitive auction or auction price offer result; or (3) the Commission rejects the results of an auction.

Q. Does the Company currently include prescriptively-structured Contingency Plans as a component of DSP IV?

A. No, it does not have prescriptively-structured Contingency Plan processes in DSP IV.

Q. Please describe the Company's proposed Contingency Plans for DSP V.

A. UGI Electric is proposing to implement a pre-defined approach to its Contingency Plans that will incorporate feedback from suppliers, feedback from the Commission in the event it rejects bid results, and that can be executed during the time available between the date of the failed product auction and the price-to-compare issuance date. Please refer to UGI Electric Exhibit SCF-8 for a summary of the Contingency Plans.

Q. How is the Company setting up its procurement process in DSP V to better accommodate its Contingency Plans?

A. The Company is proposing two auctions per year – between January through March and July through September, respectively. The intent is to conduct an energy solicitation during the first month of the window. However, in the event of a market event or if a peer utility is issuing a solicitation at the same time, UGI Electric may delay the auction to a later date. Based upon when a given auction could occur, and should the auction fail, there is between a one and three-month window to conduct follow-up bidding, prior to the tariff filing date, during which an additional contingency auction could be implemented.[7]

Q. How does the Company propose to structure its Contingency Plans in light of the longer, but potentially variable, window for taking action?

A. The Company proposes to implement an approach that pre-defines how it will proceed based upon the available window between auction failure and tariff issuance. Refer to UGI Electric Exhibit SCF-8 for a summary of the Contingency Plans for both FPFR and Block products. Assuming it has close to a full three months, which is expected to be the normal and preferred timing approach, UGI Electric will first re-auction the failed product, unmodified. The re-auction will occur approximately one month after the original auction date (i.e., February or August), including renewed outreach to suppliers to solicit interest, bidder qualification (for any new bidders) and a rebid of the product. Should the second contingency auction fail, the Company will modify the product(s) through its Contingency Plans reducing the 12-month FPFR product to a 6-month FPFR and the 24-month ATC Block down to a 6-month ATC Block, and then develop a third auction, this time for the

[7] For example, if an auction occurs in January, there are three months to complete a contingency auction before the PTC issuance on May 1 – February, March, and April; two months if conducted in February – March, and April – and one month if conducted in March – the month of April.

modified product. The third auction of the modified product will occur approximately one month later (i.e., March or September), and again include supplier outreach and qualification. Should this modified product auction fail, the final solution for the FPFR and Block products is for the Company to fill the supply gap using the spot market.

Q. What if the Company's first auction occurs later in the auction window?

A. In the event the initial solicitation is held in February or August, and therefore only two months remain between a failed auction and the tariff issuance, UGI Electric will implement the same approach for the three-month gap but delayed one month. That is, UGI Electric will re-auction the same product in March/September, re-auction a modified product (if required) in April/October, and confer with the Commission and ultimately utilize the spot market for backfilling FPFR and ATC Block supply.

Q. What if the first auction occurs at the end of the auction window?

A. In the unlikely event the initial solicitation is held in March or September due to unforeseeable factors such as a market event, and thus a single month remains between a failed bid and tariff issuance, UGI Electric will implement an abbreviated process based upon feedback from suppliers and the Commission. If it is likely that two or more bidders will rebid on the same product that failed, the Company will reissue the same product auction in April/October. However, if there seems to be an issue with the product and/or term, the Company will instead issue an auction for the modified product offering in April/October. Should either auction option fail, the Company will utilize the spot market and proceed using the same process as described above.

Q. If the Company ultimately exhausts its contingency options and goes to the spot market for 6-months, what will occur in the next auction?

A. If FPFR supply is provided through the spot market (the final option) or the ATC Block is not filled (the final option), the remaining supply (6-month FPFR and 18-month ATC Block) will be re-auctioned in the next auction window.

Q. What are the roles of the Auction Manager and UGI Electric during the Contingency Plans?

A. In the event of a failed auction, the Auction Manager will conduct outreach to suppliers that submitted bids, as well as suppliers that qualified but chose not to bid, or suppliers that initially provided interest in bidding but did not qualify, to solicit feedback seeking to determine why these suppliers behaved as they did and to inform them of the upcoming deployment of the Contingency Plan and its timeline. This information may provide insight into a flaw in the process, an unknown market event, or some other condition that could enable UGI Electric to adjust or otherwise modify its product(s) – or inform the Commission of an issue requiring input and support.

IX. AEPS COMPLIANCE

Q. Is UGI Electric required to procure AEPS credits?

A. Yes. The Pennsylvania Alternative Energy Portfolio Standard ("AEPS") Act, 73 P.S. § § 1648.1—1648.8, and the Commission's implementing regulations require UGI Electric, as an EDC, to obtain AECs equal to its default service customer supply amount –

including both GSR-1 and GSR-2 rate groups. In effect, the quantity of AECs is equivalent to the AEPS-defined percentages of electric energy sold to retail customers in the Commonwealth.[8] Under its DSP V, UGI Electric will seek to procure the AECs necessary to meet the obligations defined in the AEPS Act. The AEPS RFP will seek fixed-price bids for each tier type required under AEPS – Tier I, Solar, and Tier II.

Q. During DSP IV, did UGI Electric successfully procure the required AECs?

A. Yes, the Company has successfully procured the required AECs to meet its obligations up to this point in DSP IV. AEC solicitations have successfully acquired all AECs needed to meet UGI Electric's AEPS obligations. The Company did experience a single failed AEPS RFP for Solar AECs in May 2024. However, the Company was ultimately able to purchase the full number of solar Renewable Energy Credits ("RECs") needed by deploying the Contingency Plans for its energy supply auctions contained in DSP IV (i.e., make a spot market procurement). As a result of this experience, the Company is proposing a more comprehensive Contingency Plan applicable to AEPS auctions.

Q. What portion of required AECs does UGI Electric need to purchase for its portfolio?

A. For GSR-1, a majority of AECs will be secured through the proposed FPFR load-following contracts. As a component of the full requirements supply service, FPFR suppliers will be responsible for obtaining necessary Tier I, Solar, and Tier II AECs in an amount that corresponds to their contracted load obligation of retail supply provided during the contract term. FPFR contracts are estimated to provide approximately 76% of total GSR-1 supply,

[8] See 52 Pa. § Code 54.182.

with the remaining supply provided through ATC Block and the Allegheny Agreement supply contracts. The FPFR contracts will serve to provide the majority of AECs needed for state compliance. As a result, UGI Electric is only responsible for securing approximately 24% of GSR-1 AECs, and 100% of GSR-2 AECs.

Q. Please explain how UGI Electric will procure AECs related to GSR-1 and GSR-2 for DSP V.

A. For the supply not covered by FPFR contracts, UGI Electric will acquire the necessary AECs through a competitive AEC solicitation. Refer to UGI Electric Exhibit SCF-9 for a copy of the AEC RFP. The Company proposes to use the same Agreement that was approved by the Commission's January 22, 2009 Order (approving the *Joint Petition for Settlement of UGI Electric's AEPS Plan* at Docket Nos. P-2008-2063006 and G-2008-2063688). This AEPS agreement form was used in the Company's DSP IV Plan. A copy of the AEPS agreement is provided as UGI Electric Exhibit SCF-10. Specifically, UGI Electric will be obligated to acquire separate AECs for the following activities:

- In association with the ATC Block Supply;
- In association with NYPA Supply;
- For any spot-market settled load resulting from the differences between scheduled and settled FPFR contracts; and
- For any adjustments in the Tier I supply obligation as made by the Commission or its administrator on a quarterly basis for the above three mentioned elements or for FPFR supply contracts.

In addition, UGI Electric will procure AECs for all its GSR-2 default service procurements through the AEC RFP process.

Q. Is UGI Electric proposing any modifications to its procurement of AECs?

A. Yes. The Company is proposing four modifications: (1) moving its AEPS RFP bid date earlier than currently conducted to coincide with FPFR and ATC Block RFP dates; (2) adjusting the approach to calculating necessary AECs to eliminate short-fall risk; (3) prescribing AEC vintage requirements; and (4) implementing a Contingency Plan in the event an auction for one or more AEC Tier types is not successful.

Q. Why is UGI Electric proposing to move its AEC RFP bid date?

A. Currently, UGI Electric conducts its AEPS RFP in May, just before the annual AEPS compliance window ends, with the contract running June through May. As explained previously, the Company has had difficulty gaining high levels of supplier participation in its AEC auctions, with the most recent May 2024 auction failing to secure any bid for Solar AECs and only obtaining a single supplier in conjunction with Tier I and Tier II AECs. In an effort to improve supplier participation and, by extension, competition and pricing, UGI Electric is proposing to conduct the AEPS solicitation earlier, coinciding with its FPFR and ATC Block RFPs being conducted in January through March, with the objective of soliciting for AECs one month after the wholesale energy auction is completed. By conducting the auction earlier and in conjunction with the energy auction, UGI Electric will move to a period when less competition for AECs is occurring – i.e., before the May to August window when all load serving entities are seeking AECs for Pennsylvania AEPS

compliance – and to a time when wholesale suppliers are still active and engaged with the Company.

Q. What additional efforts is UGI Electric implementing to improve supplier participation in the AEC auction process?

A. The Company and the Auction Manager intend to conduct outreach to prospective AEC suppliers, similar to the outreach for the energy auctions. Additionally, UGI Electric will post a notice on the PJM Generation Attribute Tracking System ("GATS") about the prospective solicitation to entice AEC suppliers to the AEPS RFP process. The Auction Manager will also issue communications to all AEC Aggregators and Brokers reported on the Commission's AEPS website, notifying suppliers of the prospective auction.

Q. Why is UGI Electric proposing to modify the method for calculating AECs?

A. UGI Electric is proposing to modify the calculations it used in DSP IV in determining the number of AECs it must procure to ensure adequate AECs are procured to meet its AEPS obligations. Specifically, the Company will forecast the number of AECs required to meet its ATC Block contract needs, any adjustments as a result of FPFR scheduled versus settlement obligations, NYPA Supply needs, Tier I Adjustments, and GSR-2 obligations and apply an additional 15% increase to the total number of AECs to be procured. The current process runs the risk of under-procuring required AECs because the Company forecasts its AEC obligations. If analysis inadvertently under-forecasts AEC needs, UGI Electric would be required to either conduct a second auction or acquire AECs through the spot market. By increasing the forecasted AEC need by 15%, the Company is expecting to

slightly over-procure AECs, ensuring it will meet the AEPS obligation. These excess AECs can then be rolled into the next year, reducing the AECs needed in that year.

Q. Does this adjustment in the calculation operate in conjunction with the proposed adjustment to add vintages to the AEC procurement process?

A. Yes. The adjustment in the calculation will be accompanied by a mandatory AEC vintage requirement. Specifically, UGI Electric will provide FPFR suppliers with the maximum vintage requirements – the current compliance year at that time plus the immediately preceding two historic years.[9] AECs competitively procured will have specific vintage requirements to ensure that any excess AECs can be rolled to the next compliance year for use. In practice, this is expected to translate to 15-20% of AECs procured through the AEPS RFP that will have a limited AEC vintage that requires retirement in the current compliance year or one compliance year into the future. The remaining 80% will be providing the maximum vintage of the current compliance year, plus the following two years. Doing this will ensure that AECs can be carried forward, if needed, into the next compliance year and eliminate the risk that these AECs will lose value.

Q. Please describe the Company's proposal to adopt a Contingency Plan specific to the AEPS RFP.

A. During DSP V, the Company is proposing to implement a Contingency Plan applicable to the AEPS RFP if UGI Electric experiences a failed auction for any of the three tiers of AECs being solicited. In such an event, the Company will contact AEC Brokers and

[9] For example, if UGI is securing AECs for the 2023/24 AEPS compliance year, FPFR suppliers may provide AECs from 2023/24, 2022/23, or 2021/22.

Aggregators (Brokers), as defined on the PUC AEPS website, to determine if any Brokers have the necessary AECs, including the vintages required. If the AECs are potentially available in the market, UGI Electric will solicit bids from at least three different Brokers. Brokers will provide a fixed price for all AECs of the specified vintages. The lowest price offering will be selected. If UGI Electric cannot obtain proposals from enough Brokers to meet the minimum solicitation requirement, then the Company will discuss further contingency approaches with the Commission before contracting for the AECs being sought.

Q. Are there procurement-related costs that could result if the Company does not meet the above-stated AEPS compliance obligation?

A. Yes. According to the AEPS regulations, if UGI Electric fails to procure the needed AECs commensurate with its AEPS obligation, and the regulation defined and Commission-approved force majeure provisions were not met, the Company would be obligated to pay the applicable alternative compliance payment(s) specified in 52 Pa. Code § 75.65(b). These payments are discussed in the direct testimony of Ms. Hazenstab, UGI Electric Statement No. 3.

X. AGREEMENTS AND FORMS

Q. What agreements and forms will be used to secure default supplies in DSP V?

A. For DSP V, the Company will use a master supply agreement (i.e., EEI agreement), RFP documents, and credit and confidentiality agreements. The credit and confidentiality agreements are found in Appendix C to the Petition. Moreover, UGI Electric plans to acquire default service supplies for DSP V through the same EEI Agreement form used in

DSP IV. There are three substantive changes to the EEI Agreement: (1) the pull-back of non-market-based charges from suppliers to UGI Electric, (2) the guidance on payment for capacity pricing, and (3) inclusion of fixed fee performance assurance. The NMB pull-back and capacity pricing have been incorporated into Schedule P of the EEI Agreement. The Performance Assurance provisions have been added to Article 8 of the Agreement.

Q. Is UGI Electric updating the RFP instruction in DSP V?

A. Yes. For DSP V, in addition to utilizing the revised EEI agreement, UGI Electric will also update the RFP instructions. There are a series of updates made to these instructions to ensure the RFP aligns with the changes and updates discussed above. These include:

- Updates to products being procured, including type, size (load share or MW value) and term;
- Update in solicitation windows;
- Inclusion of a FPFR Load Share limit;
- Inclusion of Bid Assurance requirement;
- Inclusion of Contingency Plans; and
- Update to explain a block product may not be procured if customer usage declines.

Both clean and redline versions of these documents can be found in UGI Electric Exhibits SCF-5, SCF-6, and SCF-9.

Q. Does this conclude your testimony?

A. Yes.

Exhibit SCF - 1

DAYMARK ENERGY ADVISORS

AREAS OF EXPERTISE

Procurement and Portfolio Management (PPM)

Regulatory Advisory Services

Utility Ratemaking

Grid Modernization

Expert Witness

BACKGROUND

Daymark Energy Advisors
1999 – Present

Decisions Economics LLC
1994 – 1999

Weil & Howe, Inc.
1990 – 1999

Vermont Department of Public Service
1986 – 1990

EDUCATION

Certified Energy Procurement (CEP) Professional
Association of Energy Engineers

Master of Public Administration
University of Vermont

NARUC Graduate Studies Program in Regulatory Economics
Michigan State University

B.A., Economics
University of Vermont

Stan Faryniarz, CEP

Principal Consultant

Stan advises clients on matters regarding power procurement, power supply planning, regulated cost recovery, and rates. He is the primary advisor to clients with power supply portfolios totaling approximately 300 MW and over $200 million in annual spend, and he has procured and overseen well in excess of $1 billion in energy transactions and commerce over his consulting career. Stan has testified before state and provincial regulatory agencies on issues including integrated resource planning, cost of service and rate design, general rate case applications, power project siting and regulatory approvals, and federal and state policies ranging from PURPA, to net metering and grid modernization.

SELECTED PPM EXPERIENCE

- Leads Daymark's energy Procurements & Portfolios and Rates & Pricing practice areas.
- Advise utilities, aggregators and regulatory authorities in contract negotiations, energy procurement, default service power supply, competitive solicitations, auction design, transaction closing, bill auditing and dispute resolution.
- Led procurement and portfolio strategy for numerous end-user clients across the U.S. ranging from public utilities to public authorities to large commercial industrial clients in industries as varied as transportation, to defense, to vineyards.
- Advising the New Hampshire PUC in default service procurement matters as well as investor-owned utility rate applications.
- Lead procurement and energy portfolio advisor for the last 25 years to the National Passenger Railroad Corporation (Amtrak) assisting with, among other things, utility interconnection issues and retail purchase power procurement and power supply management for an annual $100 million, 200+ MW portfolio of traction and non-traction accounts in eight states and three northeastern U.S. control areas. Structure power procurement solicitations, hedging transactions, negotiate power purchase agreements and special contracts, advise on economic dispatch, and serve as an expert witness on rate and related matters, all to reduce and stabilize costs.
- Lead procurement and energy portfolio advisor to the Massachusetts Port Authority on electricity and natural gas energy procurement and management for its industrial operation since 2012. Prepares and assists with managing its $30 million energy budget, designed and implements its

current energy hedging plan and strategy, leads its participation in the ISO New England wholesale marketplace, and oversees special projects such as energy-related environmental policies, development of renewable resources including solar projects, assistance with operating and capital budgeting, and benefit-cost analyses including fuel switching and potential cogeneration improvements at its Central Heating Plant.

- Advisor to the Narragansett Bay Commission for the last 16 years in energy procurement, optimization of the economics of generation assets, market outlooks for energy, capacity and renewable energy certificates (RECs), and in marketing the RECs from its wind and anaerobic digester facilities.
- Energy advisor for the last 12 years to the Materials Innovation and Recycling Authority on its waste to energy and jet engine peaking generation units, which total almost 200 MW. Advisor on its generation assets' participation in the ISO New England wholesale marketplace and lead on its energy market price forecasting and revenue projections.
- Power supply manager for Littleton Water & Light Department, a municipal electric and water utility in New Hampshire, for the last 20 years. Enrolled and manage its ISO New England direct wholesale market participation, load and resources bid submissions, bill verification, annual budgeting, and monthly reporting functions, and assist in identifying long-term, renewables-based resources to augment its supply portfolio.
- Power supply manager for Woodsville Water & Light Department, a municipal electric and water utility in New Hampshire, for 16 years. Procure power supply, manage local network service transmission provider interactions, annual budgeting and monthly reporting functions, rate design, and acquisition of renewable energy supplies.
- Advisor to PowerOptions (MA) aggregation program on electricity and natural gas supplier solicitations, including outreach, technical, financial proposal and indicative pricing review, interviews and selection, and standard contract terms and conditions.
- Advisor to Rhode Island League of Cities and Towns REAP aggregation program on electricity supplier RFP development, technical, creditworthiness and indicative pricing set-up and review, supplier selection and standard contract terms and conditions.
- For Wallingford, CT Electric Division and other municipal electric systems, assisted with managing its departure from the Connecticut Municipal Electric Energy Cooperative (CMEEC) to become a direct wholesale market participant in ISO-NE and related transmission asset interface, assisted with draft of energy risk management and hedging policy.
- Developed Daymark Energy Advisors wholesale market outlook models and presentations, specialized hedging and risk management models and protocols, forward market-based procurement specification models, evaluation models, PPA and confirm model contracts, electronic bid intake and reverse auction solicitation programs and models.

DAYMARK ENERGY ADVISORS

STAN C FARYNIARZ, CEP
SELECTED TESTIMONY, APPEARANCES & ADVISORY SERVICES

FORUM	ON BEHALF OF	MATTER
New Hampshire Public Utility Commission	NH PUC Staff	Docket 24-070 Public Service Company of New Hampshire Request for Change in Distribution Rates **[DID NOT SPONSOR TESTIMONY; SERVING AS STAFF TECHNICAL EXPERT]**
Connecticut Public Utilities Regulatory Authority (PURA)	National Railroad Passenger Corporation (Amtrak)	Docket 24-01-03 PURA Annual Review of the Rate Adjustment Mechanism of The Connecticut Light and Power Company
Maryland Public Service Commission	National Railroad Passenger Corporation (Amtrak)	Case No. 9692 Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan
Pennsylvania Public Utility Commission	National Railroad Passenger Corporation (Amtrak)	Docket No. R-2021-3024601 Pennsylvania Public Utility Commission vs PECO Energy Company – Electric Division
Connecticut Public Utilities Regulatory Authority (PURA)	PURA Technical Staff	Docket 22-08-08 Application of the United Illuminating Company to Amend its Rate Schedule **[DID NOT SPONSOR TESTIMONY; SERVED AS STAFF TECHNICAL EXPERT]**
Hawaii Public Utility Commission	Kauai Island Utility Cooperative	Docket 2022-0208 In the Matter of the Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Matters
Pennsylvania Public Utility Commission	Delaware County, PA	Docket No. A-2019-3015173 Application of Aqua Pennsylvania Wastewater, Inc. pursuant to Sections 507, 1102 and 1329 of the Public Utility Code For, inter alia, approval of the acquisition of the wastewater system assets of the Delaware County Regional Water Quality Control Authority
Court of Common Pleas of Delaware County, Pennsylvania	County Council of Delaware County, PA	County of Delaware, Pennsylvania v. Delaware County Regional Water Control Authority (DELCORA), et al.
Maryland Public Service Commission	National Railroad Passenger Corporation (Amtrak)	Case No. 9645 Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan
Georgia Public Service Commission	Georgia PSC Public Interest Advocacy Staff	Docket No. 42516 In the Matter of Georgia Power Company's 2019 Rate Case
Vermont Public Utility Commission	Town of Stowe Electric Department	Petition of Town of Stowe Electric Department pursuant to 30 V.S.A §§ 225 and 227(a) for a 7.9% rate increase to take effect on a service-rendered basis August 15, 2018 Case No. 18-2372-TF. June 2018.

FORUM	ON BEHALF OF	MATTER
Public Service Commission of Utah	Utah Division of Public Utilities	Investigation of the costs and benefits of PacifiCorp's net metering program, which addressed allocated cost of service, rate design, and net energy metering rate design Docket No. 14-035-114. July 2017
New Hampshire Public Utilities Commission	New Hampshire Public Utilities Commission Staff	Development of new alternative net metering tariffs and/or other regulatory mechanisms and tariffs for customer-generators (net energy metering, rate design) Docket No. DE 16-576. December 2016, January 2017, and March 2017.
Public Service Commission of Utah	Utah Division of Public Utilities	Application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Utah and for approval of its proposed electric service schedules and electric service regulations Docket No. 13-035-184. May, June, and July 2014.
Pennsylvania Public Utility Commission	National Railroad Passenger Corporation (Amtrak)	Pennsylvania Public Utility Commission vs. PPL Electric Utilities Corporation Docket No. R-2015-2469275
Pennsylvania Public Utility Commission	National Railroad Passenger Corporation (Amtrak)	Petition of PPL Electric Utilities Corporation for waiver of the distribution system improvement charge cap of 5% of billed revenues Docket No. P-2015-2474714
Rhode Island Public Utilities Commission	Town of New Shoreham	Block Island Power Company request for a rate change application Docket No. 3655
Rhode Island Public Utilities Commission	National Railroad Passenger Corporation (Amtrak)	Narragansett Electric Company's proposal to introduce two new companion generic tariffs to its existing tariffs relating to High Voltage Delivery Service. Docket No. 2867
Vermont Public Service Board (now Vermont Public Utility Commission)	Town of Stowe Electric Department	Petition of Town of Stowe Electric Department, pursuant to 30 V.S.A. §§ 225 and 227(a), for a 7.9% rate increase to take effect on a service-rendered basis August 15, 2018. Case No. 18-2372-TF
Vermont Public Service Board (now Vermont Public Utility Commission)	Town of Stowe Electric Department	Petition for approval of the company's 2015 rate design and tariff amendments (rate design) Docket No. 8463
Vermont Public Service Board	Washington Electric Cooperative	Petition for approval of rate design changes and a change in rate schedules pursuant to 30 V.S.A. § 225 (rate design) Docket No. 7575
Vermont Public Service Board	Washington Electric Cooperative	Petition for: (1) a Certificate of Public Good pursuant to 30 V.S.A. § 248(j) authorizing the Second Coventry Project Expansion; and (2) approval of Washington Electric Cooperatives' promissory note to the Rural Utilities Service pursuant to 30 V.S.A. § 108 to finance the Second Coventry Project Expansion. (Certificate of Public Good) Docket No. 7455

FORUM	ON BEHALF OF	MATTER
Vermont Public Service Board	Washington Electric Cooperative	Petition for: (1) a Certificate of Public Good pursuant to 30 V.S.A. § 248(j) authorizing the First Coventry Project Expansion; and (2) approval of Washington Electric Cooperatives' promissory note to the National Rural Utilities Cooperative Finance Corporation (CFC) pursuant to 30 V.S.A. § 108 to finance the Coventry Project Expansion (IRP, Certificate of Public Good) Dockets No. 6896 & 7432
Vermont Public Service Board	Washington Electric Cooperative Coventry Clean Energy Corporation	Joint petition for: (1) a certificate of public good authorizing Coventry Clean Energy Corporation to operate as a corporation that generates and transmits electricity; (2) authorization for Washington Electric Cooperative to have a 100% ownership interest in Coventry Clean Energy Corporation; (3) approval for Coventry Clean Energy Corporation to sell all its generation to Washington Electric Cooperative; (4) approval of Washington Electric Cooperative's promissory note to the Rural Utilities Service; and (5) approval of Coventry Clean Energy Corporation's promissory note to Washington Electric Cooperative (Certificate of Public Good) Docket No. 6925
Vermont Public Service Board	Washington Electric Cooperative, Inc. Vermont Electric Power Company, Inc. Citizens Electric Company Vermont Electric Cooperative, Inc.	Joint petition for a Certificate of Public Good pursuant to 30 V.S.A. § 248 authorizing: (1) Washington Electric Cooperative to construct an electric generation station in Coventry, Vermont; (2) Washington Electric Cooperative and Vermont Electric Power Company to make improvements to the Irasburg substation; (3) Washington Electric Cooperative, Vermont Electric Cooperative, and Citizens Communications Corporation to construct 46 kV transmission lines in Coventry and Irasburg, Vermont, including provisions for distribution system construction by Citizens Communications Corporation and Vermont Electric Cooperative (Certificate of Public Good) Docket No. 6924
Vermont Public Service Board	Vermont Electric Cooperative, Inc. and Citizens Electric Company	Joint petition for transfer of assets and transfer and assignment of Hydro-Québec contracts (merger, load forecast, power supply contract disallowance) Docket Nos. 6850 & 6853
Vermont Public Service Board	Washington Electric Cooperative	Investigation into the tariff filing of Washington Electric Cooperative re: proposed rate design changes Docket No. 6328
Vermont Public Service Board	Washington Electric Cooperative	Investigation into the tariff filing of Washington Electric Cooperative for a 3.8% rate increase Docket No. 6315
Maryland Public Service Commission	National Railroad Passenger Corporation (Amtrak)	Phase II in the matter of the current and future financial condition of Baltimore Gas and Electric Company (merger) Case No. 9173. August 2009.

FORUM	ON BEHALF OF	MATTER
Pennsylvania Public Utility Commission	National Railroad Passenger Corporation (Amtrak)	Petition of the PPL Electric Utilities Corporation for approval of a default service program and procurement plan for the period January 1, 2011 through May 31, 2014 Docket No. P-2008-2060309
Pennsylvania Public Utility Commission	National Railroad Passenger Corporation (Amtrak)	Application of Safe Harbor Water Power Corporation pursuant to Section 1102(a)(2) of the Pennsylvania Public Utility Code authorizing Safe Harbor Water Power Corporation to abandon public service authorized by a Certificate of Public Convenience Docket A-2008-2078319
Pennsylvania Public Utility Commission	Pennsylvania Office of Consumer Advocate	York Water Company vs. Pennsylvania PUC (rate case, rate design) Dockets R-00016236 & R-00016236C0001-C0006
Maine Public Utilities Commission	Camden & Rockland Water Company et al	Petition for a proposed increase in rates and rate design Docket No. 93-145
Nova Scotia Utility and Review Board	Small power project developer	Investigation into non-utility generation resources and U.S. PURPA Qualifying Facility policies
Vermont Public Service Board	Vermont Department of Public Service	Investigation into the tariff filing for VPX Inc. (rate case) Docket No. 5411
Vermont Public Service Board	Vermont Department of Public Service	Review of Bonneville Pacific Corporation's proposed cogeneration facility Docket Nos. 5395 & 5401
Vermont Public Service Board	Vermont Department of Public Service	Investigation into fee schedules for VPX Inc. (rate case) Docket No. 5298
Vermont Public Service Board	Vermont Department of Public Service	Investigation into least cost investments, energy efficiency, conservation and management of the demand for energy (IRP) Docket No. 5270
Vermont Public Service Board	Vermont Department of Public Service	Petition of Great Falls Hydroelectric for 30-year levelized rates pursuant to Rule 4.100 (PURPA QF) Docket No. 5233
Vermont Public Service Board	Vermont Department of Public Service	Petition of Vermont Department of Public Service requesting deletion of the decremental pricing provision contained in the contract between VPX Inc. and Missisquoi Associates approved in Docket 5106 (PURPA QF) Docket No. 5193
Vermont Public Service Board	Vermont Department of Public Service	Petition of First Energy Associates vs. VPX Inc. re: Decker Energy Letter of Intent with VPX (PURPA QF) Docket No. 5181
Vermont Public Service Board	Vermont Department of Public Service	Petition of East Georgia Cogeneration re: approval of levelized rates pursuant to Rule 4.100 and issuance of a Certificate of Public Good pursuant to 30 V.S.A. §§ 248 (PURPA QF) Docket No. 5179
Vermont Public Service Board	Vermont Department of Public Service	Rule 4.100, Small Power Production Rates filed by the Vermont Department of Public Service (PURPA QF; avoided costs) Docket No. 5177

FORUM	ON BEHALF OF	MATTER
Vermont Public Service Board	Vermont Department of Public Service	Petition of Comtu Falls Hydro for Long-term Levelized Rates pursuant to Rule 4.100 (PURPA QF) Docket No. 5168
Vermont Public Service Board	Vermont Department of Public Service	Agreement for sale of electricity between VPX Inc. and Vermont Marble Power Company pursuant to Rule 4.100 (PURPA QF) Docket No. 5109
Vermont Public Service Board	Vermont Department of Public Service	Petition of Bio-Energy Corporation for 30-year power sales contract pursuant to Rule 4.100 (PURPA QF) Docket No. 4964
Vermont Public Service Board	Vermont Department of Public Service	Petition of Emerson Falls Hydroelectric for 30-year power sales contract pursuant to Rule 4.100 (PURPA QF) Docket No. 4949
Bennington Vermont Family Court	Judith Livingston	Livingston vs. Livingston, Valuation of Environmental Power Corporation for Plaintiff (Valuation) Docket No. F182-6-93BnDmd
Joint Hearing of the Vermont House Commerce and Senate Finance Committees	Vermont Department of Public Service	1987, Valuation of the Vermont Electric Power Company (VELCO) (Valuation)

Exhibit SCF - H

	DSP IV	DSP V
Products	- ATC Block (energy only) - Peak Block (peak energy only) - Fixed Price Full Requirements Supply - NYPA supply (energy/capacity)	- Fixed Price Full Requirements Supply - ATC block (energy only) - NYPA supply (energy/capacity)
Product Size (% of load or MW)	- 12mo FPFR: ~25% of total load (2 tranches) - 24mo FPFR: ~25% of total load - 1-month ATC Blocks: Vary 15-25MW - 1-month Peak Blocks: Vary 10-20MW - NYPA Supply: ~250kW	- 12mo FPFR: 100% of remaining load (after block) - 24mo ATC block: 20MW at steady state - NYPA Supply: ~250kW
Terms	- 12mo FPFR (2 tranches) - 24mo FPFR - 1-month ATC Blocks (procured in 6mo terms) - 1-month Peak Blocks (procured in 6mo terms) - NYPA long-term contract *(NOTE: start of plan included 6mo FPFR)*	- 12mo FPFR - 24mo ATC block - NYPA long-term contract *(NOTE: Start of plan includes 6mo FPFR)*
Frequency of product procurement	- ATC and Peak block procured every auction - 12mo FPFR procured every auction - 24mo FPFR procured once every 2 years - NYPA (perpetually renewed)	- ATC block procured once per year for 10MW (total 20MW) - 12mo FPFR procured every auction - NYPA (perpetually renewed)
Load share limit	None	Implement a FPFR load limit so that no supplier may win more than one tranche (i.e. ~50% of supply). No limit placed on Block supply.
Capacity Pricing Risk	No instruction provided	For FPFR suppliers, if a PJM Capacity Price is incomplete for a period in which a supplier is bidding, the most up to date information is to be used. UGI Electric will compensate the supplier (or receive a refund) for the difference between the price used and the final price implemented by PJM. If a PJM Capacity Price is not avalable for a period in which a supplier is bidding, the most recent prior capacity price is to be used. UGI Electric will compensate the supplier (or receive a refund) for the difference between the price used and the final price implemented by PJM.
PJM Market Costs	- FPFR - responsibility of supplier - Block - responsibility of UGI	- FPFR - Non-market-based charges responsibility of UGI, all other costs responsibility of supplier (energy, capacity, additional ancillary charges) - Block - responsibility of UGI
Energy Auctions	2x per year; April and October	2x per year Windows: 1) January-March, and 2) July-September
Energy Product Contingency	Spot Market	Iterative approach of rebid for product, alteration of product term, and/or utilization of spot market. If alteration of product or use of spot market, bid remaining load in next auction.
Bid Collateral	None	FPFR - $75,000 per tranche Block - $75,000 per tranche

	DSP IV	DSP V
Performance Assurance Collateral	None	FPFR - $175,000 per tranche Block - $100,000 per tranche
Special Provisions	None	If net metering and/or customer shopping increases UGI Electric may eliminate solicitation of a future Block procurement to maintain size of FPFR product size
AEC Auctions	Auction held in May	Auction held February through April, in the month following the energy auction for the same period (e.g. January through March)
AEC Auction Contingency	None	If time available, rebid product in the next month; if no time for a rebid, contact AEC Brokers and Aggregators (at least 3) and select the lowest bid
Net Metering (NM)	No discussion/rules	Net metering customers with supply peak load impact at or greater than 100kW will be assigned to the GSR-2 rate schedule; those below 100kW will be assigned to the GSR-1 rate schedule.

Exhibit SCF - 3

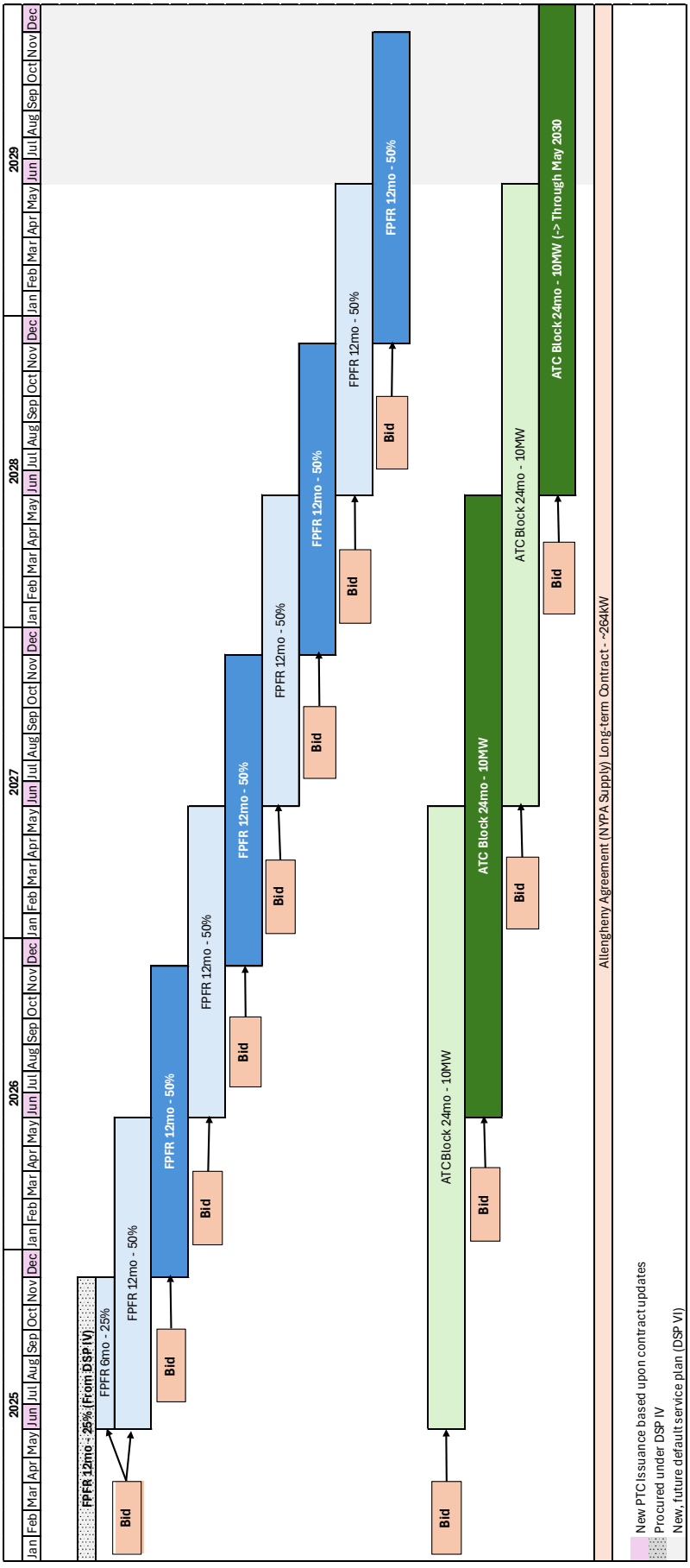

2025
2026
2027
2028
2029
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec
FPFR 12mo - 25% (From DSP IV)
FPFR 6mo - 25%
FPFR 12mo - 50%
Bid
ATC Block 24mo - 10MW
ATC Block 24mo - 10MW (-> Through May 2030
Allegheny Agreement (NYPA Supply) Long-term Contract - ~264kW
New PTC Issuance based upon contract updates
Procured under DSP IV
New, future default service plan (DSP VI)

Exhibit SCF-4

AGREEMENT FOR ELECTRIC SERVICE

AGREEMENT made this 5th day of January 2004, between ALLEGHENY ELECTRIC COOPERATIVE, INC., a corporation organized and existing under the Electric Cooperative Law of Pennsylvania, as Bargaining Agent for the Commonwealth of Pennsylvania, (hereinafter called the "Bargaining Agent") and the UGI UTILITIES, INC. a corporation organized and existing under the laws of the Commonwealth of Pennsylvania (hereinafter called the "Company");

WHEREAS, Allegheny Electric Cooperative, Inc., is the Bargaining Agent for the Commonwealth of Pennsylvania for all activities associated with Pennsylvania's allocations of hydroelectric power and energy obtained from the Power Authority of the State of New York, now know as the New York Power Authority (hereinafter called the "Authority");

WHEREAS, proceedings have been held or are ongoing to determine the allocations of hydroelectric power and energy to Neighboring States as required under the Niagara Redevelopment Act (P.L. 85-159, 16 U.S.C. § 836, 836a) and the Niagara and St. Lawrence Project licenses;

WHEREAS, it has been determined that the Commonwealth of Pennsylvania shall receive an allocation of such hydropower and energy from the Niagara and St. Lawrence Projects (hereinafter referred to as the "Projects");

WHEREAS, the Federal Energy Regulatory Commission ("FERC") has determined that the Niagara Redevelopment Act and the Niagara Project ("Niagara Project") license, unlike the license for the St. Lawrence-FDR Project ("St. Lawrence Project"), contains a federal preference provision limiting recipient entities to distributing public bodies and non-profit cooperatives and such preference provision governs the Pennsylvania allocation of hydropower and energy from the Niagara Project;

WHEREAS, the Company, as an applying utility serving rural and domestic customers in the Commonwealth of Pennsylvania is entitled to a proportionate share of the allocation of power and energy generated at the St. Lawrence Project and/or Niagara Projects;

WHEREAS, it is the responsibility of the Bargaining Agent to reallocate and contract for the sale of Pennsylvania's allocation based upon the legal requirements contained in the applicable laws and licenses and other agreements under which the Projects are operated and allocations determined;

WHEREAS, the Authority and/or Bargaining Agent has allocated to the Company the amount(s) of power specified in Appendix 1 to this Agreement.

NOW THEREFORE, in consideration of the mutual undertakings herein contained, the parties hereby agree as follows:

1. Delivery of Authority Power and Associated Energy

Bargaining Agent shall arrange for the delivery of the Authority power and associated energy (plus interruptible energy) to the New York-Pennsylvania state line ("Border") for ultimate delivery to the Company.

2. Inability to Receive the Allocated Power and Energy

If the Company is unable or unwilling to receive the allocation for any period, for any reason, such allocation: (a) to the extent that it is derived from the St. Lawrence Project, shall be divided among the Commonwealth's qualified remaining allocatees of St. Lawrence Project power and energy and (b) to the extent that it is derived from the Niagara Project, shall be divided among all Commonwealth and Neighboring States qualified remaining allocatees of Niagara Project power and energy able and willing to receive such power and energy on a pro-rata basis for the duration of such period.

3. Subject to Service Tariff AEC-1 and/or AEC-2

This Agreement and the furnishing of electric service hereunder are subject in all respects to the provisions of Bargaining Agent's Service Tariffs AEC-1 and AEC-2 as applicable (current copies of which are attached hereto), as now in effect and as may be amended by Bargaining Agent hereafter, and to such other tariffs as the Bargaining Agent may promulgate pursuant to this Agreement, which may be required by the provisions of the Authority's Rules and Regulations for Power Service, including the Authority's applicable Service Tariffs now in effect and to such other tariffs as the Authority may later promulgate pursuant to its contracts and/or agreements for allocations of power and energy to Neighboring States, all as they may be later amended from time to time; provided, that, in the event of any inconsistencies, conflicts or differences between the provisions of the Authority's Service Tariffs and the Authority's Rules and regulations for power service, the provisions of the Service Tariffs shall govern.

4. Company's Individual Liability

In the event the Bargaining Agent shall not have duly and promptly fulfilled its obligations and undertakings under its contracts and/or agreements with the Authority, the Company shall be individually liable to Authority for all the obligations and undertakings of the Bargaining Agent under its contracts and/or agreements with the Authority and under the Authority's Service Tariffs pursuant to which electric service is furnished under this Agreement to the extent such obligations and undertakings are applicable to service furnished to the Company or to the system of the Company or to the consumers served by the Company.

5. Term of Agreement

This Agreement together with the applicable Service Tariff(s) shall constitute an agreement between the parties for electric service hereunder. Such agreement, with respect to the St. Lawrence Project only, shall become fully effective upon the final approval and execution, by the governor of the State of New York, of an "Agreement for the Sale of St. Lawrence-FDR Project Power and Energy to Neighboring States" between the Power Authority and Allegheny Electric Cooperative, Inc., Bargaining Agent for the Commonwealth of Pennsylvania ("St. Lawrence Agreement"). Until such time as the St. Lawrence Agreement is signed by the Governor, the St. Lawrence Project allocation to Pennsylvania is being provided pursuant to an "Extension of Commitment for Sales of Power and Energy from St. Lawrence–FDR Project" between the Authority and the Bargaining Agent dated September 24, 2003. Unless renewed, the St. Lawrence Agreement shall remain in effect until midnight of April 30, 2017, subject to prior cancellation or modification as provided for in the aforedescribed St. Lawrence Agreement or Authority's Rules and Regulations for Power Service and/or Service Tariffs of the Authority or Bargaining Agent relating to this Agreement. This Agreement also covers Company's allocation, if any, from the Niagara Project through August 31, 2007 as provided for in the Contract for the Sale of Hydropower to Neighboring States dated February 28, 1990 as amended, including, without limitation, the Niagara Project Power and Energy Contract Extension letter agreement dated September 24, 2003.

6. Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Commonwealth of Pennsylvania to the extent such laws are not inconsistent with the St. Lawrence or Niagara Project licenses or other controlling rules, regulations or agreements.

7. Regulatory Agency or Court Modification

In the event of a binding final decision by the FERC or by a court of competent jurisdiction, establishing in the judgment of the Authority and the Bargaining Agent, that the allocation of power and energy set out in the contracts and/or agreements with the Commonwealth and/or the aggregate Neighboring State allocations and the appropriate tariffs, be adjusted, then such contracts and/or agreements and tariffs shall be appropriately amended by the Authority, the Bargaining Agent and the Company to conform to such decision.

8. Address of parties

Correspondence involving the administration of this Agreement shall be directed as follows:

To: Bargaining Agent

Vice President- Power Supply and Engineering
Allegheny Electric Cooperative, Inc.
212 Locust Street, P.O. Box 1266
Harrisburg, PA 17108-1266

To: Company

Joseph T. Racho, Senior Analyst
UGI Utilities, Inc.
100 Cashel Blvd., Suite 400
Reading, PA 19607

AND NOW, the parties hereto intending to be legally bound have applied their hands and corporate seals on the day and year first abovementioned.

Bargaining Agent
Allegheny Electric Cooperative, Inc

(SEAL)

By: _____
Richard W. Osborne
Vice President–Power Supply and Engineering

Attest: _____
Laurence V. Bladen Assistant Secretary

UGI Utilities, Inc.

By: _____ QCB
~~Joseph T. Racho, Senior Analyst~~
ROBERT J. CHANEY, PRESIDENT & CEO

(SEAL)

Attest: _____
ASSIST. SEC.

APPENDIX 1

To

AGREEMENT FOR ELECTRIC SERVICE

BETWEEN

ALLEGHENY ELECTRIC COOPERATIVE, INC.
BARGAINING AGENT

AND

UGI UTILITIES, INC.

Period	St. Lawrence Firm (kW)
February 1, 2004 through April 30, 2017	139

Period	Niagara Firm (kW)	Niagara Peaking (kW)
February 1, 2004 through August 31, 2007	0	0

ALLEGHENY ELECTRIC COOPERATIVE, INC.

BARGAINING AGENT FOR

COMMONWEALTH OF PENNSYLVANIA

SERVICE TARIFF AEC-1

FIRM POWER AND ASSOCIATED ENERGY

PLUS

INTERRUPTIBLE ENERGY

APPLICABLE:

To sale of firm hydroelectric power and associated energy plus interruptible energy allocated to Bargaining Agent by the New York Power Authority ("Authority"). Said classes of power and energy are produced at the Authority's Niagara and St. Lawrence-FDR Projects ("Projects").

AVAILABILITY

Available to those investor-owned, municipal and electric cooperatives electric light and power systems, which have applied for and have been granted an allocation from Bargaining Agent. In the case of an investor-owned utility, said allocation will be furnished from the Authority's St. Lawrence/FDR Project ("St. Lawrence Project") only. In the case of a municipal or cooperative system, said allocation will be furnished from both Projects.

CHARACTER OF SERVICE:

Alternating current; 60 hertz; three-phase.

RATE FOR SERVICE (Per Month):

MONTHLY CUSTOMER CHARGE: $180.00

DEMAND CHARGE: All kilowatts of billing demand as measured at the Project(s)' switchyard at the following rates:

12 Month Period Commencing	Demand Rate ($/kW-mth)
May 1, 2003	1.45
May 1, 2004	1.71
May 1, 2005	2.09
May 1, 2006	2.35

The demand charge for any future periods will be based on the Authority's rate in effect and the Company's Project(s) allocation for such period.

ENERGY CHARGE: All kilowatt-hours at 4.92 mills per kWh at the Project(s) switchyard(s) as subject to adjustment in accordance with the Authority's supply contracts and/or agreements with Bargaining Agent.

NEW YORK TRANSMISSION CHARGES: The allocable share of all charges assessed by the New York Independent System Operator (NYISO) or such successor organization, including but not limited to, transmission charges, ancillary services and losses for delivery of the Company's share of power and energy from the Project(s) across its transmission system to the Pennsylvania/New Jersey/Maryland Interconnection, LLC (PJM) or such successor organization for ultimate delivery to the Company.

PENNSYLVANIA TRANSMISSION CHARGE: The charges assessed by PJM and/or any other Pennsylvania transmission provider and billed directly to the Company for delivery of the Company's share of power and energy from the Project(s) across its/their transmission system(s) to the Company's system.

MINIMUM MONTHLY CHARGE:

The amount per kilowatt of allocation measured at the Project(s) switchyard(s).

CONTRACT DEMAND:

Amount(s) specified in Appendix 1 of the Agreement for Electric Service.

DETERMINATION OF BILLING DEMAND:

The billing demand(s) shall be the contract demand(s) defined above.

SPECIAL PROVISIONS:

Special provisions for service furnished under this Service Tariff are attached hereto and incorporated herein.

TERMS OF PAYMENT:

All services furnished hereunder shall be billed by Bargaining Agent on or as near as possible to the fifth working day of the month following the month during which service was furnished. Bills for service shall be paid for at the offices of Bargaining Agent in Harrisburg, Pennsylvania, on or before: (1) the last working day of the month (if payment is by wire transfer) in which the bill was rendered or, (2) two working days prior to the last working day of the month (if payment is by check) in which the bill was rendered. If the Company fails to pay such bill within the time frame specified above, Bargaining Agent may arrange for the discontinuation of service hereunder upon five working days written notice to the Company of its intention so to do and also providing an additional five-day working days to correct the delinquency. Also, whether or not Bargaining Agent shall have discontinued supplying services hereunder, if the Company shall fail to pay any bill rendered by Bargaining Agent within the aforesaid time period, then the amount of such payment plus accrued interest at a rate equal to the "Prime Rate" plus one percent (1%) per annum shall be due and payable. The "Prime Rate" is defined as the rated published in the Wall Street Journal's "Money Rates" table the first business day after such payment is due.

EFFECTIVE DATE:

January 5, 2004

ALLEGHENY ELECTRIC COOPERATIVE, INC.

SERVICE TARIFF AEC-1

SPECIAL PROVISIONS

Special Provisions for service furnished under this Service Tariff with regard to deliveries to the Company are as follows:

A. **Availability of Firm and Interruptible Energy**

Each Company receiving service under this Service Tariff shall be offered firm energy at the same load factor per kilowatt of firm contract demand as measured at the respective 'Project(s) switchyard(s). Also, interruptible energy will be provided by the Authority when available. In the event that the generating capacity of the Project(s) are modified, the per kilowatt rating on which the firm load factor is predicated shall be correspondingly modified consistent with actions taken by the Authority.

B. **Delivery**

1. **Delivery** - power and energy supplied hereunder shall first be made available to Bargaining Agent by the Authority and delivered to the Company's Pennsylvania Transmission Agent via the NYISO transmission system, as three-phase current alternating at a nominal frequency of 60 Hertz at the points and voltages of interconnection between the transmission system(s) of the NYISO (or its successor) and the Company's Pennsylvania Transmission Agent(s) at the New York State line ("Border"). Company will make the necessary arrangements with its Pennsylvania Transmission Agent(s) and directly pay it/them for delivering the power and energy supplied hereunder to Company's system. For the purposes of the Agreement for Electric Service (Agreement), power and energy shall be deemed to be offered for sale when the Authority is able to supply such power and energy and the NYISO transmits it to designated points of interconnection with Company's Pennsylvania Transmission Agent(s). If despite such offer, there is a failure of delivery by the Company or Company's Pennsylvania Transmission Agent(s), such failure shall not be subject to a billing adjustment pursuant to Section 454.6(d) of the Authority's Rules and Regulations for Power Service. Other points of interconnection of the transmission system(s) of the NYISO with the Company's Pennsylvania Transmission Agent(s), as shall be mutually agreed upon by the Authority and/or the NYISO and the Bargaining Agent and/or the Pennsylvania Transmission Agent(s), may be established in the future.

2. **Billing** - for billing purposes only, the power and energy delivered to the Company's Pennsylvania Transmission Agent(s) shall be measured at, or computed as though measured at, the Project(s) switchyard(s). The actual power and energy delivered to the Company's Pennsylvania Transmission Agent(s) shall be the amount made available at the Project(s) switchyard(s) as may be adjusted for NYPA losses, if any.

Actual or estimated meter readings, for billing periods of approximately 30 days ending with the last day of each month, shall be provided to Bargaining Agent and the Authority by Bargaining Agent's Dispatching Agent not later than the 5th working day of the following month. Upon commencement of service, deliveries will be in accordance with schedules established pursuant to Special Provision F.

C. **Payment**

1. The Company shall pay Bargaining Agent for firm power and energy and interruptible energy, if any, during any billing period the sum of (a), (b), (c), (d) and (e) below:

a. The monthly customer charge specified in this Service Tariff AEC-1 or any modification thereof.

b. The demand charge per kilowatt for firm power specified in Service Tariff AEC-1 and/or AEC-2 or any modification thereof, applied to the Company's billing demand(s) for the billing period.

c. The energy charge specified in Service Tariff AEC-1 and/or AEC-2 or any modification thereof, applied to the amount of firm and interruptible energy delivered to the Company during such billing period.

d. The transmission charges of the NYISO specified in Service Tariffs AEC-1 and/or AEC-2 or any modification thereof, applied to Company's allocation(s) specified in the Agreement.

e. The Bargaining Agent Costs Charge specified in Appendix 1 to Special Provisions of Service Tariffs AEC-1 and AEC-2.

2. The rates for power and energy sold pursuant to Service Tariffs AEC-1 and/or AEC-2 may be revised by Bargaining Agent from time to time to accommodate any changes in Bargaining Agent's administrative and general expenses and all approved changes in Authority's power and energy charges and NYISO transmission charges.

3. Upon the provision of reasonable notice, the Company shall have the right at its expense to audit and examine the accounts, books and records of Bargaining Agent relating to the transactions herein contemplated, during normal business hours, at the place where such accounts, books and records are normally maintained.

D. **Resale of Power and Energy**

The Company agrees that in reselling power and energy purchased from Bargaining Agent it shall: (1) do so pursuant to the appropriate laws of the Commonwealth of Pennsylvania, (2) do so without profit other than reasonable compensation for administrative and service costs (as allowed by the regulatory agency authorized by law to regulate the rates and practices of any distributing entity) for use of facilities and for services furnished in the transmission and distribution of such power and energy and (3) with respect to the sale and distribution of such power and energy comply with the provisions of the Niagara Redevelopment Act (P.L. 85-159, 16 U.S.C. §§836, 836a.), if applicable, and the New York Power Authority Act (N.Y. Pub. Auth.

Law Section 1000 et seq.) to the extent such Act is not inconsistent with the Niagara Redevelopment Act, if applicable, and the Project(s)' licenses.

The Company shall keep its books, accounts and records, pertaining to the purchase, delivery and sale of Authority power and energy according to procedures deemed necessary by Authority to ensure compliance with applicable statutes, licenses and rules and regulations. Also, upon the provision of reasonable notice, Company shall provide such information and permit such inspection of its books and records through Bargaining Agent as the Authority may reasonably request.

E. **Cancellation or Modification**

Service under Service Tariffs AEC-I and/or AEC-2 shall be subject to: (1) cancellation by the Company for any reason upon 90 days prior written notice to Bargaining Agent, or (2) cancellation or modification by the Authority or Bargaining Agent: (a) if such termination or modification is deemed necessary by the Authority or Bargaining Agent to comply with any ruling, order or decision of any regulatory or judicial body having jurisdiction over the subject matter of this Agreement, or (b) as otherwise provided herein or in the Authority's Rules and Regulations for Power Service (Part 454 of Title 21 of the New York Codes Rules and Regulations).

F. **Scheduling Procedures**

Bargaining Agent's Dispatching Agent, in cooperation with the Authority shall develop hourly schedules for delivery of Authority power and energy to Pennsylvania and to points designated by Bargaining Agent as required for control of interconnected operation and interchange accounting. Such schedules will be developed the month prior to delivery and will reflect the losses, if any, associated with the deliveries. All values will be rounded to the nearest MW or MWh.

APPENDIX 1 TO SPECIAL PROVISIONS OF SERVICE TARIFFS

AEC-1 AND AEC-2

Each Company shall be responsible for Bargaining Agent Costs incurred on behalf of the Pennsylvania recipients of an Authority allocation from the Project(s) ("PA Recipients"), including but not limited to the following Bargaining Agent activities: (1) making appropriate arrangements with the Authority and NYISO (or its successor) for the Pennsylvania allocation and its transmission to the New York–Pennsylvania border, (2) intervening and participating in FERC NYISO Open Access Transmission Tariff proceedings; (3) participating in the Niagara relicensing (4) negotiating the recently completed settlement and other contracts and/or agreements with the Authority involving the Niagara and St. Lawrence Project allocations (5) preparation of new Agreements for Electric Service between the Bargaining Agent and PA Recipients, and (6) other necessary and appropriate activities pursuant to its responsibilities as Bargaining Agent.

These costs generally consist of the following kinds of Bargaining Agent expenses:

1. Consultant Fees (Legal-Engineering)

2. Administrative/Personnel Costs

3. Miscellaneous Expenditures (Travel, Lodging, etc.)

Each Company's share shall be determined based upon its proportionate share of the PA Recipients' allocations from the Projects. (See Schedule A attached). Expenses will generally be accumulated by Bargaining Agent for periods of approximately six months and separately identified and billed to the PA Recipients on the same bill as the other Authority-related allocation charges.

Should the current Pennsylvania allocations be changed by the FERC or any court of competent jurisdiction, Schedule A will be adjusted accordingly on a prospective basis.

ALLEGHENY ELECTRIC COOPERATIVE, INC.
BARGAINING AGENT FOR THE COMMONWEALTH OF PENNSYLVANIA
SCHEDULE A
TO APPENDIX 1 OF SPECIAL PROVISIONS

2004 Pennsylvania	Total Authority Allocation (kW)	Percent of Total
Allegheny Electric Cooperative	31,076	62.91
Berlin	164	0.33
Chambersburg	1,396	2.83
Ellwood City	598	1.21
Ephrata	1,035	2.10
Girard Borough	224	0.45
Grove City	476	0.96
Hooversville	65	0.13
Kutztown	296	0.60
Lansdale	994	2.01
Lehighton	399	0.81
Mifflinburg	307	0.62
Mont Alto	94	0.19
Olyphant	376	0.76
Perkasie	556	1.13
Schuylkill Haven	421	0.85
Watsontown	156	0.32
Weatherly	182	0.37
Met-Ed (FirstEnergy)	1,143	2.31
PECO	3,526	7.14
Penelec (FirstEnergy)	1,289	2.61
PPL	2,944	5.96
UGI	139	0.28
West Penn (AP)	1,544	3.13
Total	49,400	100.00%

Exhibit SCF - 5

UGI Utilities, Inc. – Electric Division
Default Service Plan V – Request for Proposal
[AUCTION OPEN – Month Day, Year]

1. UGI Utilities, Inc. – Electric Division ("UGI") is seeking quotes for a load following service for the period [Month Day, Year] through [Month Day, Year] which will follow **50%** of the actual hourly requirements for its customers with peak loads of less than 100kW ("GSR-1 Group"). This group consists of both residential and smaller commercial and industrial customers. Pricing for this load will be a fixed bid price delivered to the [Insert Delivery Point]. Bids must conform to the standards approved by the Pennsylvania Public Utility Commission ("PUC") in UGI's Default Service Supply filing (Docket Nos. P-2024-[Number] and G-2024-[Number]).

2. All submitted bids must remain open until UGI receives approval or rejection of bid results from the Pennsylvania PUC.
    a. Window is explicitly between: [*Bid submission date*] through or before [*Date of PA PUC Approval; Bid Date + 2 Days*]

3. All bids must be submitted:
    a. By email to ugirfp@ugi.com
    b. On bid Date: [Month Date, Year]
    c. Within the following bid window hours: [HOUR START] and no later than **[HOUR END].**

4. **Bids received that have a time stamp later than [HOUR END] will not be considered.**
    a. UGI or the UGI Auction Manager will confirm receipt of bid within 30 minutes of receipt per the contact information provided on the Bid Submission Form

5. Bidders are submitting a load following bid for the entire term [*6, 12, or 24-months*] of the product.

6. Bids are inclusive of all energy, capacity, ancillary services (*excluding non-market-based transmission service charges* – see Item 13), and commensurate Pennsylvania Alternative Energy Credits (see Item 15).

7. All bids will be ranked based solely upon price, with the lowest priced bid being awarded the contract. In the event two or more bids are received that contain identical prices, the ties will be broken by selecting the bid of the counterparty

that has the fewest contract in effect across all DSP V products for the period in which this product will be providing service. If this method does not break the tie, the winning bidder will be chosen at random by the UGI Auction Manager.

8. To be deemed a competitive solicitation, the PA PUC must review and approve the auction results. If this requirement is not met, bids will be deemed void, bidder notified, and the Company will proceed per its Contingency Plan.

9. Supplies will be physical firm energy-only delivered at the [Insert Delivery Point]

10. The Edison Electric Institute Master Agreement ("EEI Contract") UGI and the counterparty will control all transactions completely under this RFP.

11. All bids must be submitted in U.S. dollars.

12. All bids must be accompanied with a certification form (see attachment) that the bidder is: 1) a qualified market buyer and seller of electricity in good standing with PJM; 2) positioned to obtain and deliver electric generation suppliers in PJM; 3) compliant with all applicable PJM requirements; and 4) authorized by FERC to sell and procure energy, capacity and ancillary services at market-based rates.

13. Suppliers providing service to this product are ***not responsible*** for the non-market-based transmission services listed below. These costs or credits shall not be a component of your bid. If a Bidder is successful in this solicitation, following execution of the contracts and establishment of contract terms through the PJM-specified system, UGI will enter Billing Line Item ("BLI") adjustments commensurate with these PJM BLI terms, removing the obligation from the winning supplier and transferring them to UGI. The PJM BLIs that will be transferred from the Supplier to UGI are as follows:

    Charges:
    - 1100 – Network Integration Transmission Service
    - 1102 – Network Integration Transmission Service (exception)
    - 1108 – Transmission Enhancement
    - 1140 – Non-firm Point-to-Point Transmission Service
    - 1730 – Expansion Cost Recovery
    - 1930 – Generation Deactivation

    Credits:
    - 2100 – Network Integration Transmission Service
    - 2108 – Transmission Enhancement
    - 2140 – Non-firm Point-to-Point Transmission Service
    - 2730 – Expansion Cost Recovery
    - 2930 – Generation Deactivation

14. PJM Capacity – In the event a PJM capacity price has not been issued by PJM, or is not final – having completed a Base Residual Auction and three incremental auctions – during the term of supply for which this product is being bid (see Item 16, "Energy Requested") Bidders are instructed to use the best available PJM Capacity price for the UGI zone.
    a. In such an event, UGI will provide instruction to qualified bidders concerning the capacity price to be used. Communications will be issued at least 3 business days prior to the bid day (See Item 3).
    b. The winning bidder, throughout the course of the contract, will be compensated based upon the difference between the PJM Capacity price utilized in the bid and the actual, published and final PJM Capacity price issued during the term. If the actual price is greater than the proxy price, suppliers will be compensated the difference; if the actual price is lower, UGI will be credited by suppliers for the difference.

15. Alternative Energy Credit (AEC) Obligations – As defined in Item 6, Bids are inclusive of the obligation to provide UGI with AECs. Suppliers are to transfer to UGI AECs commensurate with the load (MWh) provided per this contract each month. Obligations are defined based upon the Pennsylvania Alternative Energy Portfolio Standard (PA AEPS), comprised of Tier I, Solar, and Tier II AECs.
    a. All AECs must be transferred to UGI by or before July 15 of each year for which the Bidder has an obligation
    b. The Tier I credit obligation is defined as the base Tier I obligation minus the Solar obligation (i.e. the net of Tier I and Solar)
    c. AEC provide must be of a usable vintage for the period in which load was provide (See Item 18).

16. PJM Contract Set-up – through the course of establishing contract terms through the PJM system, Suppliers may be required to establish PJM short names. These short names are used to facilitate the transfer of NMBs from the Supplier to UGI and also link individual contracts within PJM as defined by PJM IDs. If a short name is required, UGI will work with suppliers who have won contract supply to establish the short name characters, ensuring unique identification and proper allocation or remove of PJM charges and credits.

17. All bidders must also provide UGI with Bid Assurance Collateral in the amount of $100,000.

    a. No bids submitted will be evaluated without providing and UGI accepting/confirming Bid Assurance Collateral
        i. Collateral must be provided and accepted by or before 12:00:00 pm E.T. on the Friday before the bid date.
        ii. UGI will issue a formal communication by email that collateral was received.

iii. If any issues exist, UGI will contact the Bidder to discuss and rectify the identified issue.

b. Collateral may be in the form of cash or a Letter of Credit.
   i. If bidder choose to utilize cash, UGI will provide wire instructions and will request bid return wire instructions
   ii. If the bidder chooses to utilize a Letter of Credit, UGI will provide a template of terms, including those which may not be adjusted or altered, for review and use by bidder and their banks

c. Bid assurance Collateral will be returned as follows:
   i. To bidders not selected through the competitive solicitation:
      1. Cash: within 2 business days following PUC Decision [DATE]
      2. Letter of Credit: within 3 business days following PUC Decision [DATE]
   ii. To Selected/Winning Bidders as follows:
      1. Cash: within 2 business days following fully executed contract documents.
      2. Letter of Credit: within 3 business days following fully executed contract documents.

18. All bidder inquiries should be directed to UGI at: ugirfp@ugi.com

19. **Energy Requested**

Delivery Point	[Insert Delivery Point]
Supply Type	Fixed Price **Load Following Full Requirements**
Supply Size	50%*
Term of Delivery and Quantity	[term of contract; e.g. 24-month]
Supply Start:	[Month Day, Year] Hour Ending 01:00:00 ET
Supply End:	[Month Day, Year] Hour Ending 24:00:00 ET

20. A Bid Response For is attached. Bids must be submitted on a form similar to the attached to be considered by UGI

**Note: the 50% load following obligation is based upon the total GSR-1 default service customer load share after the application of the Around-the-Clock Block ("ATC Block"), energy-only supply contracts. UGI intends to competitively secure 10MW of ATC Block, which will be in effect from June 1, 2025 through May 31, 2027, and an additional 10MW ATC Block in effect from June 1, 2026 through May 31, 2028. This amounts for a total of 20MW of ATC Block staring June 1,*

2026. This ATC Block, or its equivalent, will be maintained throughout the DSP V supply period (i.e. May 31, 2029) through successive procurements of 10MW ATC Block. ATC Block is defined as 24x7 energy-only supply. Any change in ATC Block will be made prospectively only, with such changes communicated to bidders prior to a bid for FPFR supply.

UGI Utilities, Inc. – Electric Division
Default Service Plan V – Request for Proposal Response Form
[BID DATE - Month Day, Year]

This bid is submitted in response to UGI's Request for Proposal as issued [AUCTION OPEN DATE – Month Date, Year].

Supplier Name _____

Contact Person and Phone _____

Supply Type Fixed Price Load Following Full Requirements Service

Delivery Point [Insert Delivery Point]

Term	Price ($/MWh)*
[Month Day, Year] – [Month Day, Year]	

**Excluding Non-market-based Transmission Service Charges.*

All bids must be submitted by e-mail to ugirfp@ugi.com by [Month Day, Year]**, within the bid window of [HOUR START] to [HOUR END]. Bids received with a time stamp later than [HOUR END] will not be considered.**

Bids must remain open until the close of business (5:00 p.m. E.T) on [PUC APPROVAL DATE - Month Day, Year]. Bidders must have an EEI Contract in place with UGI for bids to be awarded. Winning bidders have two business days to execute the confirmation agreement.

PJM Qualification Certification Form

I, _____ ("Agent of Bidder") am an authorized signatory for _____ ("Bidder") and hereby certify that Bidder is a member of PJM Interconnection, LLC ("PJM") and is qualified as a market buyer and market seller in good standing to secure generation or otherwise obtain and deliver electricity in PJM through compliance with all applicable requirements of PJM to fulfill the contracted supply obligation.

Signed: Date:

_____ _____

Type or Print Name of Officer:

_____

Title: _____

Company: _____

[Date]

Dear Sir or Madam:

RE: Request for Proposal (RFP) to Purchase Electric Default Service Supplies

UGI Utilities, Inc. – Electric Division ("UGI") is seeking electric supply to serve a portion of its Default Service requirements. The Request for Proposal ("RFP") and bidding details are attached hereto.

The Pennsylvania Public Utility Commission ("PUC") approved UGI's petition for a Default Service Program in Docket Nos. P-2024-_____ and G-2024-_____. This plan established the mechanism by which UGI would acquire supplies for its customers that are not being served by an alternate generation supplier. UGI's plan approved by the PUC utilizes a competitive solicitation process to secure these supplies. Therefore, UGI is issuing this RFP requesting bids on certain quantities of energy as specified in the RFP. All acquisitions made through RFP's will be managed by a third party, [Auction Manager], to ensure a fair and unbiased process.

RFP Schedule

[Date]	Notice of RFP sent to potential suppliers
[Date]	Bidder Information Session
[Date] (2:00 p.m. E.T.)	RFP Conference Call with all interested parties Call-in Number: TBD Code: TBD
[Date] (3:00 p.m. E.T.)	Last day to submit questions via email to ugirfp@ugi.com
[Date] (12:00 p.m. E.T.)	Bid Assurance Collateral Due Date (by or before)
[Bid Date] (11:00 a.m. E.T.)	RFP responses due to UGI/[Auction Manager]
[Bid Date] (12:00 p.m. E.T.)	Winning bidders selected by UGI/ [Auction Manager], and verbally notified by UGI/[Auction Manager of bid status
[Bid Date] (1:30 p.m. E.T.)	Results of solicitation sent to Pennsylvania PUC
[Bid Date+1]	Pennsylvania PUC provides a decision of the results of the RFP
[Bid Date+1]	UGI/[Auction Manager] verbally notifies winning bidders following PUC approval

Responses to this RFP will be submitted through e-mail to ugirfp@ugi.com. Questions pertaining to this RFP can also be sent to the email address up to 3:00 p.m. on [Date]. Questions and Responses will be posted on UGI's website which can be found at:

[Insert Link]

Responses to this RFP will be accompanied by a certification form that the bidder is: 1) a qualified market buyer and seller of electricity in good standing with PJM; 2) positioned to obtain and deliver electric generation supplies in PJM; 3) compliant with all applicable PJM requirements; and 4) authorized by FERC to sell and procure energy, capacity and ancillary services at market-based rates. Bidder must also provide required Bid Assurance Collateral as defined in the RFP.

Through the e-mail address to which RFP responses are sent, both UGI and [Auction Manager] will receive your bid, evaluate the responses and determine the winning bidder. Once the winning bidder is determined, the results will be forwarded to the PUC, who will either accept or reject the winning bid(s). UGI/[Auction Manager] will also notify winning bidder(s) of their tentative selection as a winning bidder. Therefore, all bids must remain open until the end of the business day following submission. UGI's approved Default Service plan specifies that the PUC will issue its decision within one business day. While UGI cannot direct the PUC to adhere to the expected timeline, it is hoped the PUC will approve the results of the RFP by the close of business on the day following the due date of the bids. Immediately following the PUC's decision, UGI will contact the winning bidder by telephone to confirm the transaction. A confirmation agreement will be exchanged to finalize the transaction.

In order for a bid to be awarded, there must be a fully executed EEI Contract in place with UGI. The basic framework of the contract was set forth in UGI's filing and will be provided upon request. The contract is also posted on UGI's website at:

[Insert Link]

The criterion for selecting a winning bid is price. It is UGI's intent to award this service to a single bidder. If more than one bid is received at identical prices, the tie will be broken by awarding the bid to the supplier that is providing the least amount of energy during the applicable supply period, consistent with the Pennsylvania PUC orders. If this method does not break the tie, [Auction Manager] will randomly select the winning bid.

Thank you,

UGI

Exhibit SCF - 6

UGI Utilities, Inc. – Electric Division
Default Service Plan V – Request for Proposal
[AUCTION OPEN - Month Day, Year]

1. UGI Utilities, Inc. – Electric Division ("UGI") is seeking quotes for supplying the following packages of energy for its Default Service customers (residential and smaller commercial and industrial) with peak loads of less than 100kW ("GSR-1 Group"). Bids must conform to the standards approved by the Pennsylvania Public Utility Commission (PUC) in UGI's Default Service Supply filing (Docket Nos. P-2024-_____ and G-2024-_____).

2. All submitted bids must remain open until UGI receives approval or rejection of bid results from the Pennsylvania PUC.
   a. Window is explicitly between: [*Bid submission date*] through or before [*Date of PA PUC Approval*]

3. All bids must be submitted:
   a. By e-mail to ugirfp@ugi.com
   b. On bid Date: [Month Date, Year]
   c. Within the following bid window hours: [HOUR START] and no later than [HOUR END]

4. **Bids received that have a time stamp later than [HOUR END] will not be considered.**
   a. UGI or the UGI Auction Manager will confirm receipt of bid submission within 30 minutes of receipt per the contact information provided on the Bid Submission Form

5. Bidders are submitting a fixed price bid for the entire term [*24 months or as adjusted*] of the product.

6. All bids will be ranked based solely upon price, with the lowest priced bid being awarded the contract. In the event two or more bids are received that contain identical prices, the ties will be broken by selecting the bid of the counterparty that has the fewest contracts in effect across all DSP V products for the period in which this product will be providing service (inclusive of Fixed Price Load Following Full Requirements Contracts). If this method does not break the tie, the winning bidder will be chosen at random by the UGI Auction Manager.

7. To be deemed a competitive solicitation, the PA PUC must review and approve the auction results. If this requirement is not met, bids will be deemed void, the bidder notified, and the Company will proceed per its Contingency Plan.

5. Supplies will be physical firm energy-only delivered at the [ENTER ZONE].

6. The Edison Electric Institute Master Agreement ("EEI Contract") between UGI and the counterparty will control all transactions completed under this RFP.

7. All bids must be submitted in U.S. dollars.

8. All bids must be accompanied with a certification form (see attachment) that the bidder is: 1) a qualified market buyer and seller of electricity in good standing with PJM; 2) positioned to obtain and deliver electric generation supplies in PJM; 3) compliant with all applicable PJM requirements; and 4) authorized by FERC to sell and procure energy, capacity and ancillary services at market-based rates.

   PJM Contract Set-up – through the course of establishing contract terms through the PJM system, Suppliers may be required to establish PJM short names. These short names are used to facilitate the transfer of NMBs from the Supplier to UGI and also link individual contracts within PJM as defined by PJM IDs. If a short name is required, UGI will work with suppliers who have won contract supply to establish the short name characters, ensuring unique identification and proper allocation or remove of PJM charges and credits.

9. All bidders must also provide UGI with Bid Assurance Collateral in the amount of $50,000.

   a. No bids submitted will be evaluated without providing and UGI accepting/confirming Bid Assurance Collateral
      i. Collateral must be provided and accepted by or before 12:00:00 pm E.T. on the Friday before the bid date.
      ii. UGI will issue a formal communication by email that collateral was received.
      iii. If any issues exist, UGI will contact the Bidder to discuss and rectify the identified issue.
   b. Collateral may be in the form of cash or a Letter of Credit.
      i. If the bidder chooses to utilize cash, UGI will provide wire instructions and will request return wire instructions.
      ii. If the bidder chooses to utilize a Letter of Credit, UGI will provide a template of terms, including those which may not be adjusted or altered, for review and use by bidder and their banks.
   c. Bid assurance Collateral will be returned as follows:
      i. To Bidders not selected through the competitive solicitation:
         1. Cash: within 2 business days following PUC Decision [DATE]
         2. Letter of Credit: within 3 business days following PUC Decision [DATE]
      ii. To Selected/Winning Bidder as follows:
         1. Cash: within 2 business days following fully executed contract documents
         2. Letter of Credit: withing 3 business days following fully executed contract documents

10. All bidder inquiries should be directed to UGI at: ugirfp@ugi.com

11. Energy Requested

Delivery Point	[Insert Delivery Point]
Supply Type	**7x24 (Around the Clock) physical firm, energy-only**
Supply Size	10MW
Term of Delivery and Quantity	[term of contract; e.g. 24-month]
Supply Start:	[Month Day, Year] Hour Ending 01:00:00 ET
Supply End:	[Month Day, Year] Hour Ending 24:00:00 ET

12. A Bid Response Form is attached. Bids must be submitted on a form similar to the attached to be considered by UGI.

UGI Utilities, Inc. – Electric Division
Default Service Plan V - Request for Proposal Response Form
[BID DATE - Month Day, Year]

This bid is submitted in response to UGI's Request for Proposal as issued [AUCTION OPEN DATE – Month Date, Year].

Supplier Name _____

Primary Contact Phone _____

Primary Contact E-mail _____

Term of Delivery	Supply Type	Delivery Point	Quantity (Mw)	Price ($/Mwh)
[Term, e.g. 24-months]; [Month, Day, Year through Month Day, Year]	7x24	[Insert Delivery Point]	[QTY]MW	

All bids must be submitted by e-mail to ugirfp@ugi.com by [Month Day Year]**, within the bid window of [HOUR START] to [HOUR END]. Bids received with a time stamp later than [HOUR END] will not be considered.**

Bids must remain open until the close of business (5:00 p.m. E.T) on [PUC APPROVAL DATE - Month Day, Year]. Bidders must have an EEI Contract in place with UGI for bids to be awarded. Winning bidders have two business days to execute the confirmation agreement.

PJM Qualification Certification Form

I, _____ ("Agent of Bidder") am an authorized signatory for _____ ("Bidder") and hereby certify that Bidder is a member of PJM Interconnection, LLC ("PJM") and is qualified as a market buyer and market seller in good standing to secure generation or otherwise obtain and deliver electricity in PJM through compliance with all applicable requirements of PJM to fulfill the contracted supply obligation.

Signed: Date:

_____ _____

Type or Print Name of Officer:

_____

Title: _____

Company: _____

[Date]

Dear Sir or Madam:

RE: Request for Proposal ("RFP") to Purchase Electric Default Service Supplies

UGI Utilities, Inc. – Electric Division ("UGI") is seeking electric supplies to serve a portion of its Default Service requirements. The Request for Proposals ("RFP") and bidding details are attached hereto.

The Pennsylvania Public Utility Commission ("PUC") approved UGI's petition for a Default Service Supply Plan in Docket Nos. P-2024-_____ and G-2024-_____. This plan established the mechanism by which UGI would acquire supplies for its customers that are not being served by an alternate generation supplier. UGI's plan approved by the PUC utilizes a competitive solicitation process to secure these supplies. Therefore, UGI is issuing this RFP requesting bids on certain quantities of energy as specified in the RFP. All acquisitions made through RFPs will be monitored by a third party, [Auction Manager], to ensure a fair and unbiased process.

RFP Schedule

[Date]	Notice of RFP sent to potential suppliers
[Date]	Bidder Information Session
[Date] (2:00 p.m. E.T.)	RFP Conference Call with all interested parties Call-in Number: +1 412-677-9733 Code: 960190391#
[Date] (3:00 p.m. E.T.)	Last day to submit questions via email to ugirfp@ugi.com
[Date] (12:00 p.m. E.T.)	Bid Assurance Collateral Due Date (by or before)
[Bid Date] (12:00 p.m. E.T.)	RFP response due to UGI/[Auction Manager]
[Bid Date] (1:00 p.m. E.T.)	Winning bidders selected by UGI, verified by [Au, and verbally notified by UGI of bid status
[Bid Date] (1:30 p.m. E.T.)	Results of solicitation sent to Pennsylvania PUC
[Bid Date+1]	Pennsylvania PUC provides a decision of the results of the RFP
[Bid Date+1]	UGI/[Auction Manager] verbally notifies winning bidders following PUC approval

Responses to this RFP will be submitted through e-mail to ugirfp@ugi.com. Questions pertaining to this RFP can also be sent to the email address up to 3:00 p.m. on [Date]. Questions and Responses will be posted on UGI's website which can be found at

[Insert Link]

Responses to this RFP will be accompanied by a certification form that the bidder is: 1) a qualified market buyer and seller of electricity in good standing with PJM; 2) positioned

to obtain and deliver electric generation supplies in PJM; 3) compliant with all applicable PJM requirements; and 4) authorized by FERC to sell and procure energy, capacity and ancillary services at market-based rates. Bidder must also provide required Bid Assurance Collateral as defined in the RFP.

Through this e-mail address, both UGI and [Auction Manager] will receive your bid, evaluate the responses and determine the winning bidder(s). Once UGI can determine the winning bidder(s), the results must be forwarded to the PUC, who will either accept or reject the winning bid(s). UGI/[Auction Manager] will also notify winning bidder(s) of their tentative selection as a winning bidder. Therefore, all bids must remain open until the end of the business day following submission. While UGI cannot dictate a timeline to the PUC, it is hoped the PUC will approve the results of the RFP within 24 hours of the bid deadline. UGI's Default Service Supply Plan requests the PUC to issue its decision within one business day. Immediately following the PUC's decision, UGI will then contact the winning bidder(s) by telephone to confirm the transaction. A confirmation agreement will be exchanged to finalize the transaction.

In order for a bid to be awarded, there must be a fully executed EEI Contract in place with UGI. The basic framework of the contract was set forth in UGI's filing and will be provided upon request. The information is also posted on UGI's website at

[Insert Link]

The criterion for selecting a winning bid is price. It is UGI's intent to award each energy block to a single bidder. If more than one bid is received at identical prices, the tie will be broken by awarding the bid to the supplier that is providing the least amount of energy during the applicable supply period. If this method does not break the tie, [Auction Manager] will randomly select the winning bid.

Thank you,

UGI

Exhibit SCF - 7

Version 2.1 (modified 4/25/00)
©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

Master Power Purchase & Sale Agreement

Version 2.1 (modified 4/25/00)

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

MASTER POWER PURCHASE AND SALE AGREEMENT

COVER SHEET

This *Master Power Purchase and Sale Agreement* ("*Master Agreement*") is made as of the following date: _____ ("Effective Date"). The *Master Agreement*, together with the exhibits, schedules and any written supplements hereto, the Party A Tariff, if any, the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any confirmations accepted in accordance with Section 2.3 hereto) shall be referred to as the "Agreement." The Parties to this *Master Agreement* are the following:

Name ("_____" or "Party A")

All Notices:

Street: _____

City: _____Zip: _____

Attn: Contract Administration
Phone: _____
Facsimile: _____
Duns: _____
Federal Tax ID Number: _____

Invoices:
Attn: _____
Phone: _____
Facsimile: _____

Scheduling:
Attn: _____
Phone: _____
Facsimile: _____

Payments:
Attn: _____
Phone: _____
Facsimile: _____

Wire Transfer:
BNK: _____
ABA: _____
ACCT: _____

Credit and Collections:
Attn: _____
Phone: _____
Facsimile: _____

With additional Notices of an Event of Default or Potential Event of Default to:
Attn: _____
Phone: _____
Facsimile: _____

Party B – UGI Utilities, Inc. – Electric Division

All Notices:

Street Address: 1 UGI Drive

City: Denver, PAZip: 17517

Attn: Contract Administration
Phone:_____
Facsimile:_____
Duns: 79-937-6595_____
Federal Tax ID Number: 23-1174060_____

Invoices:
Attn:_____
Phone:_____
Facsimile:_____

Scheduling:
Attn:_____
Phone:_____
Facsimile:_____

Payments:
Attn:_____
Phone:_____
Facsimile:_____

Wire Transfer:
BNK:.
ABA:_____
ACCT:_____

Credit and Collections:
Attn:_____
Phone:_____
Facsimile:_____

With additional Notices of an Event of Default or Potential Event of Default to:
Attn:
Phone:_____
Facsimile:_____

Version 2.1 (modified 4/25/00)
©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

The Parties hereby agree that the General Terms and Conditions are incorporated herein, and to the following provisions as provided for in the General Terms and Conditions:

Party A Tariff Tariff _____ Dated _____ Docket Number _____

Party B Tariff Tariff: Market Based Power Sales Tariff Dated: June 6, 2002 Docket Number: ER02-2042

Article Two

Transaction Terms and Conditions

[X] Optional provision in Section 2.4. If not checked, inapplicable.

Article Four

Remedies for Failure to Deliver or Receive

[X] Accelerated Payment of Damages. If not checked, inapplicable.

Article Five

Events of Default; Remedies

[] Cross Default for Party A:

[] Party A:_____ Cross Default Amount $50 million

[] Other Entity: Guarantor, if any Cross Default Amount $50 million

[] Cross Default for Party B:

[] Party B:_____ Cross Default Amount $_____

[] Other Entity:_____ Cross Default Amount $_____

5.6 Closeout Setoff

[X] Option A (Applicable if no other selection is made.)

[] Option B - Affiliates shall have the meaning set forth in the Agreement unless otherwise specified as follows:_____

_____

[] Option C (No Setoff)

Article 8

Credit and Collateral Requirements

8.1 Party A Credit Protection:

(a) Financial Information:

[X] Option A
[] Option B Specify: _____
[] Option C Specify: None

(b) Credit Assurances:

[] Not Applicable
[X] Applicable

(c) Collateral Threshold:

[] Not Applicable
[X] Applicable

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

If applicable, complete the following:

Party B Collateral Threshold: $10 Million; provided, however, that Party B's Collateral Threshold shall be zero if an Event of Default or Potential Event of Default with respect to Party B has occurred and is continuing.

Party B Independent Amount: $ See Collateral Annex attached hereto

Party B Rounding Amount: $ See Collateral Annex attached hereto

(d) Downgrade Event:

[X] Not Applicable
[] Applicable

If applicable, complete the following:

[] It shall be a Downgrade Event for Party B if Party B's Credit Rating or the ratings of its Guarantor falls below BBB- from S&P or Baa3 from Moody's or BBB- from Fitch's if Party A is not rated by either S&P or Moody's

[] Other:
Specify:_____

(e) Guarantor for Party B:_____

Guarantee Amount:_____

8.2 Party B Credit Protection:

(a) Financial Information:

[X] Option A
[X] Option B Specify: Guarantor, if applicable
[] Option C Specify: _____
[X] Option D

(b) Credit Assurances:

[] Not Applicable
[X] Applicable

(c) Collateral Threshold:

[] Not Applicable
[X] Applicable

If applicable, complete the following:

Party A Collateral Threshold: $ 10 million; provided, however, that Party A's Collateral Threshold shall be zero if an Event of Default or Potential Event of Default with respect to Party A has occurred and is continuing or if Party A or its guarantor does not maintain an investment grade credit rating.

Party A Independent Amount: See Collateral Annex attached hereto

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

Party A Rounding Amount: See Collateral Annex attached hereto

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

(d) Downgrade Event:

[X] Not Applicable
[] Applicable

If applicable, complete the following:

[] It shall be a Downgrade Event for Party A if Party A's Credit Rating or the ratings of its Guarantor falls below BBB- from S&P or Baa3 from Moody's or BBB- from Fitch's of if Party A or its Guarantor is not rated by either S&P or Moody's

[] Other:
Specify:_____

(e) Guarantor for Party A: To be decided

Guarantee Amount: To be decided

Article 10

Confidentiality [X] Confidentiality Applicable If not checked, inapplicable.

Schedule M

[] Party A is a Governmental Entity or Public Power System
[] Party B is a Governmental Entity or Public Power System
[] Add Section 3.6. If not checked, inapplicable
[] Add Section 8.6. If not checked, inapplicable

Other Changes: Yes

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

Article One: General Definitions

The following definitions are amended as set forth below:

1. Section 1.23 is amended by inserting in the seventh line of this Subsection after the phrase “Seller’s supply” the phrase “unless Buyer and Seller agree in the Transaction Confirmation that supply is tied to a specific source and the identified source becomes unavailable due to Force Majeure;”

2. Section 1.46 is deleted in its entirety

3. Section 1.50 is amended to delete the reference to section “2.4” and add “2.5”.

4. Section 1.51 is amended to add the phrase "for delivery" immediately before the phrase "at the Delivery Point" in the second line.

5. Section 1.53 is amended to delete the phrase "at the Delivery Point" from the second line.

Article Two: Transaction Terms and Conditions

Section 2.1 is amended by inserting on the third line after the phrase “means of communication” the phrase “such as electronic mail or real time internet messaging services”

The following is added as a separate second paragraph of Section 2.2:

> "Party A and Party B confirm that this Master Agreement shall supersede and replace all prior master power purchase and sale agreements between the parties hereto with respect to the subject matter hereof. Party A and Party B further agree that any transaction for the purchase or sale of electric energy, capacity or other related products which is in effect as of the Effective Date of this Master Agreement or which has delivery obligations that start after the Effective Date of this Master Agreement shall be governed by this Master Agreement, and are part of this single integrated agreement between the Parties consistent with the first paragraph of this Section 2.2."

Section 2.3 is amended by inserting on the second line after the word “facsimile” the phrase “or electronic mail”

Section 2.4 is amended by deleting on the seventh line the phrase “either orally or”

Section 2.5 is amended in its entirety to read as follows:

> 2.5 Recording. Unless a Party expressly objects to a Recording (defined below) at the beginning of a telephone conversation, each Party consents to the creation of a tape or electronic recording (“Recording”) of all telephone conversations between the Parties to this Master Agreement, and that any such Recordings will be retained in confidence, secured from improper access and may be submitted in evidence in any proceeding or action relating to this Agreement, provided that all objections to the admissibility of such Recording on grounds of relevancy or materiality are preserved. Each Party waives any further notice of such monitoring or recording, and agrees to notify its officers and employees of such monitoring or recording and to obtain any necessary consent of such officers and employees. A true and complete copy of a Recording made by either Party will be provided to the other Party upon request, if it reasonably appears that such recording may be utilized to resolve a dispute between the parties. The Recording, and the terms and conditions described therein, if admissible, shall be the controlling evidence for the Parties’ agreement with respect to a particular Transaction in the event a Confirmation is not fully executed (or deemed accepted) by both Parties. Upon full execution (or deemed acceptance) of a Confirmation, such Confirmation shall control in the event of any conflict with the terms of a Recording, or in the event of any conflict with the terms of this Master Agreement

Article Five: Events of Default; Remedies

Section 5.1(G) is amended to delete Subsection (ii) in its entirety

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

Section 5.1 (h)(ii) is amended to delete the following phrase from the third and fourth lines thereof: " and such failure shall not be remedied within three (3) Business Days after written notice"

New Subsection 5.1 (i) is added as follows:

(i) such Party fails to materially perform its obligation to schedule, deliver, or receive the Product pursuant to a Transaction on three (3) or more of consecutive days during the term of this Agreement (except to the extent such failure is excused by Force Majeure).

Section 5.2 is amended to delete the following phrase from the last two lines: "under applicable law on the Early Termination Date, as soon thereafter as is reasonably practicable)." The following shall be added to the end of Section 5.2: "under applicable law on the Early Termination Date, then each such Transaction (individually, an "Excluded Transaction" and collectively, the "Excluded Transactions") shall be terminated as soon thereafter as reasonably practicable), and upon termination shall be deemed to be a Terminated Transaction and the Termination Payment payable in connection with all such Excluded Transactions shall be calculated in accordance with Section 5.3 below. The Gains and Losses for each Terminated Transaction shall be determined by calculating the amount that would be incurred or realized to replace or to provide the economic equivalent of the remaining payments or deliveries in respect of that Terminated Transaction. The Non- Defaulting Party (or its agent) may determine its Gains and Losses by reference to information either available to it internally or supplied by one or more third parties including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets. Third parties supplying such information may include, without limitation, dealers in the relevant markets, end-users of the relevant product, information vendors and other sources of market information."

Article Six: Payment and Netting

Section 6.2 is amended to delete the first sentence in its entirety and to replace with the following: "Unless otherwise agreed by the Parties in a Transaction, all invoices under this Agreement shall be due and payable in accordance with each Party's invoice instructions on or before ten (10) days after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day."

Article Seven: Limitations

Section 7.1 shall be amended by: (a) deleting "Except as set forth herein" from the first sentence and "Unless expressly herein provided" from the fifth sentence, and (b) adding "Notwithstanding anything in this Agreement to the contrary" to the beginning of the fifth sentence, and "set forth in this Agreement" after "indemnity provision" and before "or otherwise," also in the fifth sentence.

Article Eight: Credit and Collateral Requirements

Section 8.1(d) shall be amended by inserting in line five after the phrase "receipt of notice" the phrase "or fails to maintain such Performance Assurance or guaranty or other credit assurance for so long as the Downgrade Event is continuing."

Section 8.2(d) shall be amended by inserting in line five after the phrase "receipt of notice" the phrase "or fails to maintain such Performance Assurance or guaranty or other credit assurance for so long as the Downgrade Event is continuing."

Article Ten: Miscellaneous

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

Section 10.8 is amended by inserting in the second to last line after the phrase "audit rights" the phrase ", and, if elected by the Parties, the Confidentiality protections of Section 10.11,".

Section 10.11 is amended (i) to add the phrase "or the completed Cover Sheet to this Master Agreement" immediately before the phrase "to a third party" and to add the phrase "or the Party's Affiliates'" immediately after the phrase "other than the Party's" and (ii) to add the following at the end of the Section:

"To the extent any information provided by the Parties pursuant to Article 8.1(a) and Article 8.2(a) of this Agreement is not in the public domain, it will be deemed confidential information subject to the non-disclosure obligations in this paragraph."

The following new Sections are added at the end of Article 10:

10.12 SUBMISSION TO JURISDICTION; SERVICE OF PROCESS. THE PARTIES AGREE TO SUBMIT TO THE NON-EXCLUSIVE JURISDICTION OF THE COURTS OF THE COMMONWEALTH OF PENNSYLVANIA. EACH PARTY AGREES TO APPOINT AN AGENT FOR SERVICE OF PROCESS IN PENNSYLVANIA UPON THE REQUEST OF THE OTHER PARTY.

10.13 Imaged Agreement. Any original executed Agreement, Confirmation or other related document may be photocopied and stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidenced on paper, the Confirmation, if introduced as evidence in automated facsimile form, the Recording, if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the Recording, the Confirmation or the Imaged Agreement (or photocopies of the transcription of the Recording, the Confirmation or the Imaged Agreement) on the basis that such were not originated or maintained in documentary form under either the hearsay rule, the best evidence rule or other rule of evidence.

.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

IN WITNESS WHEREOF, the Parties have caused this Master Agreement to be duly executed as of the date first above written.

Party A Name	UGI Utilities, Inc.
By: _____	By: _____
Name: _____	Name: _____
Title: _____	Title: _____

DISCLAIMER: This Master Power Purchase and Sale Agreement was prepared by a committee of representatives of Edison Electric Institute ("EEI") and National Energy Marketers Association ("NEM") member companies to facilitate orderly trading in and development of wholesale power markets. Neither EEI nor NEM nor any member company nor any of their agents, representatives or attorneys shall be responsible for its use, or any damages resulting therefrom. By providing this Agreement EEI and NEM do not offer legal advice and all users are urged to consult their own legal counsel to ensure that their commercial objectives will be achieved and their legal interests are adequately protected.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

GENERAL TERMS AND CONDITIONS

ARTICLE ONE: GENERAL DEFINITIONS

1.1 "Affiliate" means, with respect to any person, any other person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person. 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.

1.2 "Agreement" has the meaning set forth in the Cover Sheet.

1.3 "Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

1.4 "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

1.5 "Buyer" means the Party to a Transaction that is obligated to purchase and receive, or cause to be received, the Product, as specified in the Transaction.

1.6 "Call Option" means an Option entitling, but not obligating, the Option Buyer to purchase and receive the Product from the Option Seller at a price equal to the Strike Price for the Delivery Period for which the Option may be exercised, all as specified in the Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller will be obligated to sell and deliver the Product for the Delivery Period for which the Option has been exercised.

1.7 "Claiming Party" has the meaning set forth in Section 3.3.

1.8 "Claims" means all third party claims or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys' fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

1.9 "Confirmation" has the meaning set forth in Section 2.3.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

1.10 "Contract Price" means the price in $U.S. (unless otherwise provided for) to be paid by Buyer to Seller for the purchase of the Product, as specified in the Transaction.

1.11 "Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party 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 a Terminated Transaction; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of a Transaction.

1.12 "Credit Rating" means, with respect to any entity, the rating then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements) or if such entity does not have a rating for its senior unsecured long-term debt, then the rating then assigned to such entity as an issues rating by S&P, Moody's or any other rating agency agreed by the Parties as set forth in the Cover Sheet.

1.13 "Cross Default Amount" means the cross default amount, if any, set forth in the Cover Sheet for a Party.

1.14 "Defaulting Party" has the meaning set forth in Section 5.1.

1.15 "Delivery Period" means the period of delivery for a Transaction, as specified in the Transaction.

1.16 "Delivery Point" means the point at which the Product will be delivered and received, as specified in the Transaction.

1.17 "Downgrade Event" has the meaning set forth on the Cover Sheet.

1.18 "Early Termination Date" has the meaning set forth in Section 5.2.

1.19 "Effective Date" has the meaning set forth on the Cover Sheet.

1.20 "Equitable Defenses" means any bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

1.21 "Event of Default" has the meaning set forth in Section 5.1.

1.22 "FERC" means the Federal Energy Regulatory Commission or any successor government agency.

1.23 "Force Majeure" means an event or circumstance which prevents one Party from performing its obligations under one or more Transactions, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (i) the loss of Buyer's markets; (ii) Buyer's inability economically

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

to use or resell the Product purchased hereunder; (iii) the loss or failure of Seller's supply; or (iv) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred. The applicability of Force Majeure to the Transaction is governed by the terms of the Products and Related Definitions contained in Schedule P.

1.24 "Gains" means, 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 the termination of a Terminated Transaction, determined in a commercially reasonable manner.

1.25 "Guarantor" means, with respect to a Party, the guarantor, if any, specified for such Party on the Cover Sheet.

1.26 "Interest Rate" means, for any date, 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%) and (b) the maximum rate permitted by applicable law.

1.27 "Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a credit rating of at least A- from S&P or A3 from Moody's, in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

1.28 "Losses" means, 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 termination of a Terminated Transaction, determined in a commercially reasonable manner.

1.29 "Master Agreement" has the meaning set forth on the Cover Sheet.

1.30 "Moody's" means Moody's Investor Services, Inc. or its successor.

1.31 "NERC Business Day" means any day except a Saturday, Sunday or a holiday as defined by the North American Electric Reliability Council or any successor organization thereto. A NERC Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

1.32 "Non-Defaulting Party" has the meaning set forth in Section 5.2.

1.33 "Offsetting Transactions" mean any two or more outstanding Transactions, having the same or overlapping Delivery Period(s), Delivery Point and payment date, where under one or more of such Transactions, one Party is the Seller, and under the other such Transaction(s), the same Party is the Buyer.

1.34 "Option" means the right but not the obligation to purchase or sell a Product as specified in a Transaction.

1.35 "Option Buyer" means the Party specified in a Transaction as the purchaser of an option, as defined in Schedule P.

1.36 "Option Seller" means the Party specified in a Transaction as the seller of an option, as defined in Schedule P.

1.37 "Party A Collateral Threshold" means the collateral threshold, if any, set forth in the Cover Sheet for Party A.

1.38 "Party B Collateral Threshold" means the collateral threshold, if any, set forth in the Cover Sheet for Party B.

1.39 "Party A Independent Amount" means the amount, if any, set forth in the Cover Sheet for Party A.

1.40 "Party B Independent Amount" means the amount, if any, set forth in the Cover Sheet for Party B.

1.41 "Party A Rounding Amount" means the amount, if any, set forth in the Cover Sheet for Party A.

1.42 "Party B Rounding Amount" means the amount, if any, set forth in the Cover Sheet for Party B.

1.43 "Party A Tariff" means the tariff, if any, specified in the Cover Sheet for Party A.

1.44 "Party B Tariff" means the tariff, if any, specified in the Cover Sheet for Party B.

1.45 "Performance Assurance" means collateral in the form of either cash, Letter(s) of Credit, or other security acceptable to the Requesting Party.

1.46 "Potential Event of Default" means an event which, with notice or passage of time or both, would constitute an Event of Default.

1.47 "Product" means electric capacity, energy or other product(s) related thereto as specified in a Transaction by reference to a Product listed in Schedule P hereto or as otherwise specified by the Parties in the Transaction.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

1.48 "Put Option" means an Option entitling, but not obligating, the Option Buyer to sell and deliver the Product to the Option Seller at a price equal to the Strike Price for the Delivery Period for which the option may be exercised, all as specified in a Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller will be obligated to purchase and receive the Product.

1.49 "Quantity" means that quantity of the Product that Seller agrees to make available or sell and deliver, or cause to be delivered, to Buyer, and that Buyer agrees to purchase and receive, or cause to be received, from Seller as specified in the Transaction.

1.50 "Recording" has the meaning set forth in Section 2.4.

1.51 "Replacement Price" means the price at which Buyer, acting in a commercially reasonable manner, purchases at the Delivery Point a replacement for any Product specified in a Transaction but not delivered by Seller, plus (i) costs reasonably incurred by Buyer in purchasing such substitute Product and (ii) additional transmission charges, if any, reasonably incurred by Buyer to the Delivery Point, or at Buyer's option, the market price at the Delivery Point for such Product not delivered as determined by Buyer in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Buyer be required to utilize or change its utilization of its owned or controlled assets or market positions to minimize Seller's liability. For the purposes of this definition, Buyer shall be considered to have purchased replacement Product to the extent Buyer shall have entered into one or more arrangements in a commercially reasonable manner whereby Buyer repurchases its obligation to sell and deliver the Product to another party at the Delivery Point.

1.52 "S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor.

1.53 "Sales Price" means the price at which Seller, acting in a commercially reasonable manner, resells at the Delivery Point any Product not received by Buyer, deducting from such proceeds any (i) costs reasonably incurred by Seller in reselling such Product and (ii) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers, or at Seller's option, the market price at the Delivery Point for such Product not received as determined by Seller in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Seller be required to utilize or change its utilization of its owned or controlled assets, including contractual assets, or market positions to minimize Buyer's liability. For purposes of this definition, Seller shall be considered to have resold such Product to the extent Seller shall have entered into one or more arrangements in a commercially reasonable manner whereby Seller repurchases its obligation to purchase and receive the Product from another party at the Delivery Point.

1.54 "Schedule" or "Scheduling" means the actions of Seller, Buyer and/or their designated representatives, including each Party's Transmission Providers, if applicable, of notifying, requesting and confirming to each other the quantity and type of Product to be delivered on any given day or days during the Delivery Period at a specified Delivery Point.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

1.55 "Seller" means the Party to a Transaction that is obligated to sell and deliver, or cause to be delivered, the Product, as specified in the Transaction.

1.56 "Settlement Amount" means, with respect to a Transaction and the Non-Defaulting Party, the Losses or Gains, and Costs, expressed in U.S. Dollars, which such party incurs as a result of the liquidation of a Terminated Transaction pursuant to Section 5.2.

1.57 "Strike Price" means the price to be paid for the purchase of the Product pursuant to an Option.

1.58 "Terminated Transaction" has the meaning set forth in Section 5.2.

1.59 "Termination Payment" has the meaning set forth in Section 5.3.

1.60 "Transaction" means a particular transaction agreed to by the Parties relating to the sale and purchase of a Product pursuant to this Master Agreement.

1.61 "Transmission Provider" means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from the Delivery Point in a particular Transaction.

ARTICLE TWO: TRANSACTION TERMS AND CONDITIONS

2.1 Transactions. A Transaction shall be entered into upon agreement of the Parties orally or, if expressly required by either Party with respect to a particular Transaction, in writing, including an electronic means of communication. Each Party agrees not to contest, or assert any defense to, the validity or enforceability of the Transaction entered into in accordance with this Master Agreement (i) based on any law requiring agreements to be in writing or to be signed by the parties, or (ii) based on any lack of authority of the Party or any lack of authority of any employee of the Party to enter into a Transaction.

2.2 Governing Terms. Unless otherwise specifically agreed, each Transaction between the Parties shall be governed by this Master Agreement. This Master Agreement (including all exhibits, schedules and any written supplements hereto), the Party A Tariff, if any, and the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmations accepted in accordance with Section 2.3) shall form a single integrated agreement between the Parties. Any inconsistency between any terms of this Master Agreement and any terms of the Transaction shall be resolved in favor of the terms of such Transaction.

2.3 Confirmation. Seller may confirm a Transaction by forwarding to Buyer by facsimile within three (3) Business Days after the Transaction is entered into a confirmation ("Confirmation") substantially in the form of Exhibit A. If Buyer objects to any term(s) of such Confirmation, Buyer shall notify Seller in writing of such objections within two (2) Business Days of Buyer's receipt thereof, failing which Buyer shall be deemed to have accepted the terms as sent. If Seller fails to send a Confirmation within three (3) Business Days after the Transaction is entered into, a Confirmation substantially in the form of Exhibit A, may be forwarded by Buyer to Seller. If Seller objects to any term(s) of such Confirmation, Seller shall notify Buyer of such objections within two (2) Business Days of Seller's receipt thereof, failing

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

which Seller shall be deemed to have accepted the terms as sent. If Seller and Buyer each send a Confirmation and neither Party objects to the other Party's Confirmation within two (2) Business Days of receipt, Seller's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation, unless (i) Seller's Confirmation was sent more than three (3) Business Days after the Transaction was entered into and (ii) Buyer's Confirmation was sent prior to Seller's Confirmation, in which case Buyer's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation. Failure by either Party to send or either Party to return an executed Confirmation or any objection by either Party shall not invalidate the Transaction agreed to by the Parties.

2.4 Additional Confirmation Terms. If the Parties have elected on the Cover Sheet to make this Section 2.4 applicable to this Master Agreement, when a Confirmation contains provisions, other than those provisions relating to the commercial terms of the Transaction (e.g., price or special transmission conditions), which modify or supplement the general terms and conditions of this Master Agreement (e.g., arbitration provisions or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 2.3 unless agreed to either orally or in writing by the Parties; provided that the foregoing shall not invalidate any Transaction agreed to by the Parties.

2.5 Recording. Unless a Party expressly objects to a Recording (defined below) at the beginning of a telephone conversation, each Party consents to the creation of a tape or electronic recording ("Recording") of all telephone conversations between the Parties to this Master Agreement, and that any such Recordings will be retained in confidence, secured from improper access, and may be submitted in evidence in any proceeding or action relating to this Agreement. Each Party waives any further notice of such monitoring or recording, and agrees to notify its officers and employees of such monitoring or recording and to obtain any necessary consent of such officers and employees. The Recording, and the terms and conditions described therein, if admissible, shall be the controlling evidence for the Parties' agreement with respect to a particular Transaction in the event a Confirmation is not fully executed (or deemed accepted) by both Parties. Upon full execution (or deemed acceptance) of a Confirmation, such Confirmation shall control in the event of any conflict with the terms of a Recording, or in the event of any conflict with the terms of this Master Agreement.

ARTICLE THREE: OBLIGATIONS AND DELIVERIES

3.1 Seller's and Buyer's Obligations. With respect to each Transaction, Seller shall sell and deliver, or cause to be delivered, and Buyer shall purchase and receive, or cause to be received, the Quantity of the Product at the Delivery Point, and Buyer shall pay Seller the Contract Price; provided, however, with respect to Options, the obligations set forth in the preceding sentence shall only arise if the Option Buyer exercises its Option in accordance with its terms. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product or its receipt at and from the Delivery Point.

3.2 Transmission and Scheduling. Seller shall arrange and be responsible for transmission service to the Delivery Point and shall Schedule or arrange for Scheduling services

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

with its Transmission Providers, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of the Transmission Providers, to deliver the Product to the Delivery Point. Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive the Product at the Delivery Point.

3.3 Force Majeure. To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under the Transaction and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of the Product specify otherwise, the Claiming Party shall be excused from the performance of its obligations with respect to such Transaction (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure). The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.

ARTICLE FOUR: REMEDIES FOR FAILURE TO DELIVER/RECEIVE

4.1 Seller Failure. If Seller fails to schedule and/or deliver all or part of the Product pursuant to a Transaction, and such failure is not excused under the terms of the Product or by Buyer's failure to perform, then Seller shall pay Buyer, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

4.2 Buyer Failure. If Buyer fails to schedule and/or receive all or part of the Product pursuant to a Transaction and such failure is not excused under the terms of the Product or by Seller's failure to perform, then Buyer shall pay Seller, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Sales Price from the Contract Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

ARTICLE FIVE: EVENTS OF DEFAULT; REMEDIES

5.1 Events of Default. An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

(a) the failure 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;

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

(b) any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;

(c) the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default, and except for such Party's obligations to deliver or receive the Product, the exclusive remedy for which is provided in Article Four) if such failure is not remedied within three (3) Business Days after written notice;

(d) such Party becomes Bankrupt;

(e) the failure of such Party to satisfy the creditworthiness/collateral requirements agreed to pursuant to Article Eight hereof;

(f) such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party;

(g) if the applicable cross default section in the Cover Sheet is indicated for such Party, the occurrence and continuation of (i) a default, event of default or other similar condition or event in respect of such Party or any other party specified in the Cover Sheet for such Party under one or more agreements or instruments, individually or collectively, relating to indebtedness for borrowed money in an aggregate amount of not less than the applicable Cross Default Amount (as specified in the Cover Sheet), which results in such indebtedness becoming, or becoming capable at such time of being declared, immediately due and payable or (ii) a default by such Party or any other party specified in the Cover Sheet for such Party in making on the due date therefor one or more payments, individually or collectively, in an aggregate amount of not less than the applicable Cross Default Amount (as specified in the Cover Sheet);

(h) with respect to such Party's Guarantor, if any:

(i) if any representation or warranty made by a Guarantor in connection with this Agreement is false or misleading in any material respect when made or when deemed made or repeated;

(ii) the failure of a Guarantor to make 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;

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

(iii) a Guarantor becomes Bankrupt;

(iv) the failure of a Guarantor's guaranty 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 such Party under each Transaction to which such guaranty shall relate without the written consent of the other Party; or

(v) a Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of any guaranty.

5.2 Declaration of an Early Termination Date and Calculation of Settlement Amounts. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party (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 20 days after such notice is effective, as an early termination date ("Early Termination Date") to accelerate all amounts owing between the Parties and to liquidate and terminate all, but not less than all, Transactions (each referred to as a "Terminated Transaction") between the Parties, (ii) withhold any payments due to the Defaulting Party under this Agreement and (iii) suspend performance. The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for each such Terminated Transaction as of the Early Termination Date (or, to the extent that in the reasonable opinion of the Non-Defaulting Party certain of such Terminated Transactions are commercially impracticable to liquidate and terminate or may not be liquidated and terminated under applicable law on the Early Termination Date, as soon thereafter as is reasonably practicable).

5.3 Net Out of Settlement Amounts. The Non-Defaulting Party shall aggregate all Settlement Amounts into a single amount by: netting out (a) all Settlement Amounts that are 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 pursuant to Article Eight, plus any or all other amounts due to the Defaulting Party under this Agreement against (b) all Settlement Amounts that are due to the Non-Defaulting Party, plus any or all other amounts due to the Non-Defaulting Party under this Agreement, so that all such amounts shall be netted out to a single liquidated amount (the "Termination Payment") payable by one Party to the other. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.

5.4 Notice of Payment of Termination Payment. As soon as practicable after a liquidation, 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. The Termination Payment shall be made by the Party that owes it within two (2) Business Days after such notice is effective.

5.5 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 two (2) Business Days of receipt of Non-Defaulting Party's calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

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 Performance Assurance to the Non-Defaulting Party in an amount equal to the Termination Payment.

5.6 Closeout Setoffs.

Option A: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party to the Non-Defaulting Party under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option B: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party or any of its Affiliates to the Non-Defaulting Party or any of its Affiliates under any other agreements, instruments or undertakings between the Defaulting Party or any of its Affiliates and the Non-Defaulting Party or any of its Affiliates and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option C: Neither Option A nor B shall apply.

5.7 Suspension of Performance. Notwithstanding any other provision of this Master Agreement, if (a) an Event of Default or (b) a Potential Event of Default shall have occurred and be continuing, the Non-Defaulting Party, upon written notice to the Defaulting Party, shall have the right (i) to suspend performance under any or all Transactions; provided, however, in no event shall any such suspension continue for longer than ten (10) NERC Business Days with respect to any single Transaction unless an early Termination Date shall have been declared and notice thereof pursuant to Section 5.2 given, and (ii) to the extent an Event of Default shall have occurred and be continuing to exercise any remedy available at law or in equity.

ARTICLE SIX: PAYMENT AND NETTING

6.1 Billing Period. Unless otherwise specifically agreed upon by the Parties in a Transaction, the calendar month shall be the standard period for all payments under this Agreement (other than Termination Payments and, if "Accelerated Payment of Damages" is specified by the Parties in the Cover Sheet, payments pursuant to Section 4.1 or 4.2 and Option premium payments pursuant to Section 6.7). As soon as practicable after the end of each month,

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

each Party will render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding month.

6.2 Timeliness of Payment. Unless otherwise agreed by the Parties in a Transaction, all invoices under this Master Agreement shall be due and payable in accordance with each Party's invoice instructions on or before the later of the twentieth (20th) day of each month, or tenth (10th) day after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day. Each Party will make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any amounts not paid by the due date will be deemed delinquent and will accrue interest at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

6.3 Disputes and Adjustments of Invoices. A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within two (2) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 6.3 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the month during which performance of a Transaction occurred, the right to payment for such performance is waived.

6.4 Netting of Payments. The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing to each other on the same date pursuant to all Transactions through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Master Agreement, including any related damages calculated pursuant to Article Four (unless one of the Parties elects to accelerate payment of such amounts as permitted by Article Four), interest, and payments or credits, shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it.

6.5 Payment Obligation Absent Netting. If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, including, but not limited to, any related damage amounts calculated pursuant to Article Four, interest, and payments or credits, that Party shall pay such sum in full when due.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

6.6 Security. Unless the Party benefiting from Performance Assurance or a guaranty notifies the other Party in writing, and except in connection with a liquidation and termination in accordance with Article Five, all amounts netted pursuant to this Article Six shall not take into account or include any Performance Assurance or guaranty which may be in effect to secure a Party's performance under this Agreement.

6.7 Payment for Options. The premium amount for the purchase of an Option shall be paid within two (2) Business Days of receipt of an invoice from the Option Seller. Upon exercise of an Option, payment for the Product underlying such Option shall be due in accordance with Section 6.1.

6.8 Transaction Netting. If the Parties enter into one or more Transactions, which in conjunction with one or more other outstanding Transactions, constitute Offsetting Transactions, then all such Offsetting Transactions may by agreement of the Parties, be netted into a single Transaction under which:

(a) the Party obligated to deliver the greater amount of Energy will deliver the difference between the total amount it is obligated to deliver and the total amount to be delivered to it under the Offsetting Transactions, and

(b) the Party owing the greater aggregate payment will pay the net difference owed between the Parties.

Each single Transaction resulting under this Section shall be deemed part of the single, indivisible contractual arrangement between the parties, and once such resulting Transaction occurs, outstanding obligations under the Offsetting Transactions which are satisfied by such offset shall terminate.

ARTICLE SEVEN: LIMITATIONS

7.1 Limitation of Remedies, Liability and Damages. EXCEPT AS SET FORTH HEREIN, 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 OR IN A TRANSACTION, 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, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

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 OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE 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 THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE EIGHT: CREDIT AND COLLATERAL REQUIREMENTS

8.1 Party A Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.1(a) is specified on the Cover Sheet, Section 8.l(a) Option C shall apply exclusively. If none of Sections 8.1(b), 8.1(c) or 8.1(d) are specified on the Cover Sheet, Section 8.1(b) shall apply exclusively.

(a) Financial Information. Option A: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party B's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of Party B's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as Party B diligently pursues the preparation, certification and delivery of the statements.

Option B: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party A may request from Party B the information specified in the Cover Sheet.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

(b) Credit Assurances. If Party A has reasonable grounds to believe that Party B's creditworthiness or performance under this Agreement has become unsatisfactory, Party A will provide Party B with written notice requesting Performance Assurance in an amount determined by Party A in a commercially reasonable manner. Upon receipt of such notice Party B shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party A. In the event that Party B fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party A plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold, then Party A, on any Business Day, may request that Party B provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold (rounding upwards for any fractional amount to the next Party B Rounding Amount) ("Party B Performance Assurance"), less any Party B Performance Assurance already posted with Party A. Such Party B Performance Assurance shall be delivered to Party A within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party B, at its sole cost, may request that such Party B Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party B's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party B Rounding Amount). In the event that Party B fails to provide Party B Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.1(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party A as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party B to Party A, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party B, then Party A may require Party B to provide Performance Assurance in an amount determined by Party A in a commercially reasonable manner. In the event Party B shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default shall be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party B shall deliver to Party A, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party A.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

8.2 Party B Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.2(a) is specified on the Cover Sheet, Section 8.2(a) Option C shall apply exclusively. If none of Sections 8.2(b), 8.2(c) or 8.2(d) are specified on the Cover Sheet, Section 8.2(b) shall apply exclusively.

(a) Financial Information. Option A: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party A's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of such Party's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as such Party diligently pursues the preparation, certification and delivery of the statements.

Option B: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party B may request from Party A the information specified in the Cover Sheet.

(b) Credit Assurances. If Party B has reasonable grounds to believe that Party A's creditworthiness or performance under this Agreement has become unsatisfactory, Party B will provide Party A with written notice requesting Performance Assurance in an amount determined by Party B in a commercially reasonable manner. Upon receipt of such notice Party A shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party B. In the event that Party A fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party B plus Party A's Independent Amount, if any, exceeds the Party A Collateral Threshold, then Party B, on any Business Day, may request that Party A provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party A's Independent Amount, if any, exceeds the Party A Collateral

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

Threshold (rounding upwards for any fractional amount to the next Party A Rounding Amount) ("Party A Performance Assurance"), less any Party A Performance Assurance already posted with Party B. Such Party A Performance Assurance shall be delivered to Party B within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party A, at its sole cost, may request that such Party A Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party A's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party A Rounding Amount). In the event that Party A fails to provide Party A Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.2(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party B as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party A to Party B, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party A, then Party B may require Party A to provide Performance Assurance in an amount determined by Party B in a commercially reasonable manner. In the event Party A shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party A shall deliver to Party B, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party B.

Option D: Party B may request from Party A the information specified in the Cover Sheet, as defined below.

(a) Performance Assurances. Party B requires that Party A provide Performance Assurance Collateral in the amount of $175,000 for Fixed Price Load Following Full Requirements contracts and $100,000 for block contracts. The Performance Assurance Collateral is required following award of a supply, commensurate with the product awarded. Collateral can be in the form of cash or a bank letter of credit. If cash is provided, the Company may compensate Party A for interest accrued and the relevant interest rate as defined by Party B. The Performance Assurance Collateral provided by Party A will be returned at the conclusion of the product supply term as defined in the contract unless otherwise agreed upon by between Party A and Party B.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

8.3 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent either or both Parties deliver Performance Assurance hereunder, each Party (a "Pledgor") hereby grants to the other Party (the "Secured Party") 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, such Secured Party, and each Party agrees to take such action as the other Party reasonably requires in order 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 Non-Defaulting Party may do any one or more of the following: (i) exercise any of the rights and remedies of a Secured Party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Defaulting Party in the possession of the Non-Defaulting Party or its agent; (iii) draw on any outstanding Letter of Credit issued for its benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Secured Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under the Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

ARTICLE NINE: GOVERNMENTAL CHARGES

9.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Master Agreement in accordance with the intent of the parties to minimize all taxes, so long as neither Party is materially adversely affected by such efforts.

9.2 Governmental Charges. Seller shall pay or cause to be paid all taxes imposed by any government authority ("Governmental Charges") on or with respect to the Product or a Transaction arising prior to the Delivery Point. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or a Transaction at and from the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of the Product and are, therefore, the responsibility of the Seller). In the event Seller is required by law or regulation to remit or pay Governmental Charges which are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Governmental Charges. If Buyer is required by law or regulation to remit or pay Governmental Charges which are Seller's responsibility hereunder, Buyer may deduct the amount of any such Governmental Charges from the sums due to Seller under Article 6 of this Agreement. Nothing shall obligate or cause a Party to pay or be liable to pay any Governmental Charges for which it is exempt under the law.

ARTICLE TEN: MISCELLANEOUS

10.1 Term of Master Agreement. The term of this Master Agreement shall commence on the Effective Date and shall remain in effect until terminated by either Party upon (thirty) 30

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

days' prior written notice; provided, however, that such termination shall not affect or excuse the performance of either Party under any provision of this Master Agreement that by its terms survives any such termination and, provided further, that this Master Agreement and any other documents executed and delivered hereunder shall remain in effect with respect to the Transaction(s) entered into prior to the effective date of such termination until both Parties have fulfilled all of their obligations with respect to such Transaction(s), or such Transaction(s) that have been terminated under Section 5.2 of this Agreement.

10.2 Representations and Warranties. On the Effective Date and the date of entering into each Transaction, each Party represents and warrants to the other Party that:

(i) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(ii) it has all regulatory authorizations necessary for it to legally perform its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(iii) the execution, delivery and performance of this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(iv) this Master Agreement, each Transaction (including any Confirmation accepted in accordance with Section 2.3), and each other document executed and delivered in accordance with this Master Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms; subject to any Equitable Defenses.

(v) it is not Bankrupt 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;

(vi) there is not pending or, to its knowledge, threatened against it or any of its Affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(vii) no Event of Default or Potential 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 Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

(viii) it is acting for its own account, has made its own independent decision to enter into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) and as to whether this Master Agreement and each such Transaction (including any Confirmation accepted in accordance with Section 2.3) is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(ix) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code;

(x) it has entered into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) in connection with the conduct of its business and it has the capacity or ability to make or take delivery of all Products referred to in the Transaction to which it is a Party;

(xi) with respect to each Transaction (including any Confirmation accepted in accordance with Section 2.3) involving the purchase or sale of a Product or an Option, it is a producer, processor, commercial user or merchant handling the Product, and it is entering into such Transaction for purposes related to its business as such; and

(xii) the material economic terms of each Transaction are subject to individual negotiation by the Parties.

10.3 Title and Risk of Loss. Title to and risk of loss related to the Product shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it will deliver to Buyer the Quantity of the Product free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

10.4 Indemnity. Each Party shall indemnify, defend and hold harmless the other Party from and against any Claims arising from or out of any event, circumstance, act or incident first occurring or existing during the period when control and title to Product is vested in such Party as provided in Section 10.3. Each Party shall indemnify, defend and hold harmless the other Party against any Governmental Charges for which such Party is responsible under Article Nine.

10.5 Assignment. Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent may be withheld in the exercise of its sole discretion; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign this Agreement to an

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (iii) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

10.6 Governing Law. THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

10.7 Notices. All notices, requests, statements or payments shall be made as specified in the Cover Sheet. Notices (other than scheduling requests) shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight United States mail or courier shall be effective on the next Business Day after it was sent. A Party may change its addresses by providing notice of same in accordance herewith.

10.8 General. This Master Agreement (including the exhibits, schedules and any written supplements hereto), the Party A Tariff, if any, the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmation accepted in accordance with Section 2.3) constitute the entire agreement between the Parties relating to the subject matter. Notwithstanding the foregoing, any collateral, credit support or margin agreement or similar arrangement between the Parties shall, upon designation by the Parties, be deemed part of this Agreement and shall be incorporated herein by reference. 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. Except to the extent herein provided for, no amendment or modification to this Master Agreement shall be enforceable unless reduced to writing and executed by both Parties. Each Party agrees if it seeks to amend any applicable wholesale power sales tariff during the term of this Agreement, such amendment will not in any way affect outstanding Transactions under this Agreement without the prior written consent of the other Party. Each Party further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement. This Agreement shall not impart any rights enforceable by any third party (other than a permitted successor or assignee bound to this Agreement). Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change (individually or collectively, such events referred to as "Regulatory Event") will not otherwise affect the remaining lawful obligations that arise under this Agreement; and provided, further, that if a Regulatory Event occurs, the Parties shall use their best efforts to reform this Agreement

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

in order to give effect to the original intention of the Parties. The term "including" when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only. All indemnity and audit rights shall survive the termination of this Agreement for twelve (12) months. This Agreement shall be binding on each Party's successors and permitted assigns.

10.9 Audit. Each Party has the right, 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 Master Agreement. If requested, a Party shall provide to the other Party statements evidencing the Quantity delivered at the Delivery Point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

10.10 Forward Contract. The Parties acknowledge and agree that all Transactions constitute "forward contracts" within the meaning of the United States Bankruptcy Code.

10.11 Confidentiality. If the Parties have elected on the Cover Sheet to make this Section 10.11 applicable to this Master Agreement, neither Party shall disclose the terms or conditions of a Transaction under this Master Agreement to a third party (other than the Party's employees, lenders, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area or independent system operator rule or in connection with any court or regulatory proceeding; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation.

Version 2.1 (modified 4/25/00)
©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

SCHEDULE M

(THIS SCHEDULE IS INCLUDED IF THE APPROPRIATE BOX ON THE COVER SHEET IS MARKED INDICATING A PARTY IS A GOVERNMENTAL ENTITY OR PUBLIC POWER SYSTEM)

A. The Parties agree to add the following definitions in Article One.

"Act" means _____.[1]

"Governmental Entity or Public Power System" means a municipality, county, governmental board, public power authority, public utility district, joint action agency, or other similar political subdivision or public entity of the United States, one or more States or territories or any combination thereof.

"Special Fund" means a fund or account of the Governmental Entity or Public Power System set aside and or pledged to satisfy the Public Power System's obligations hereunder out of which amounts shall be paid to satisfy all of the Public Power System's obligations under this Master Agreement for the entire Delivery Period.

B. The following sentence shall be added to the end of the definition of "Force Majeure" in Article One.

If the Claiming Party is a Governmental Entity or Public Power System, Force Majeure does not include any action taken by the Governmental Entity or Public Power System in its governmental capacity.

C. The Parties agree to add the following representations and warranties to Section 10.2:

Further and with respect to a Party that is a Governmental Entity or Public Power System, such Governmental Entity or Public Power System represents and warrants to the other Party continuing throughout the term of this Master Agreement, with respect to this Master Agreement and each Transaction, as follows: (i) all acts necessary to the valid execution, delivery and performance of this Master Agreement, including without limitation, competitive bidding, public notice, election, referendum, prior appropriation or other required procedures has or will be taken and performed as required under the Act and the Public Power System's ordinances, bylaws or other regulations, (ii) all persons making up the governing body of Governmental Entity or Public Power System are the duly elected or appointed incumbents in their positions and hold such

[1] Cite the state enabling and other relevant statutes applicable to Governmental Entity or Public Power System.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

positions in good standing in accordance with the Act and other applicable law, (iii) entry into and performance of this Master Agreement by Governmental Entity or Public Power System are for a proper public purpose within the meaning of the Act and all other relevant constitutional, organic or other governing documents and applicable law, (iv) the term of this Master Agreement does not extend beyond any applicable limitation imposed by the Act or other relevant constitutional, organic or other governing documents and applicable law, (v) the Public Power System's obligations to make payments hereunder are unsubordinated obligations and such payments are (a) operating and maintenance costs (or similar designation) which enjoy first priority of payment at all times under any and all bond ordinances or indentures to which it is a party, the Act and all other relevant constitutional, organic or other governing documents and applicable law or (b) otherwise not subject to any prior claim under any and all bond ordinances or indentures to which it is a party, the Act and all other relevant constitutional, organic or other governing documents and applicable law and are available without limitation or deduction to satisfy all Governmental Entity or Public Power System' obligations hereunder and under each Transaction or (c) are to be made solely from a Special Fund, (vi) entry into and performance of this Master Agreement and each Transaction by the Governmental Entity or Public Power System will not adversely affect the exclusion from gross income for federal income tax purposes of interest on any obligation of Governmental Entity or Public Power System otherwise entitled to such exclusion, and (vii) obligations to make payments hereunder do not constitute any kind of indebtedness of Governmental Entity or Public Power System or create any kind of lien on, or security interest in, any property or revenues of Governmental Entity or Public Power System which, in either case, is proscribed by any provision of the Act or any other relevant constitutional, organic or other governing documents and applicable law, any order or judgment of any court or other agency of government applicable to it or its assets, or any contractual restriction binding on or affecting it or any of its assets.

D. The Parties agree to add the following sections to Article Three:

Section 3.4 Public Power System's Deliveries. On the Effective Date and as a condition to the obligations of the other Party under this Agreement, Governmental Entity or Public Power System shall provide the other Party hereto (i) certified copies of all ordinances, resolutions, public notices and other documents evidencing the necessary authorizations with respect to the execution, delivery and performance by Governmental Entity or Public Power System of this Master Agreement and (ii) an opinion of counsel for Governmental Entity or Public Power System, in form and substance reasonably satisfactory to the Other Party, regarding the validity, binding effect and enforceability of this Master

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

Agreement against Governmental Entity or Public Power System in respect of the Act and all other relevant constitutional organic or other governing documents and applicable law.

Section 3.5 No Immunity Claim. Governmental Entity or Public Power System warrants and covenants that with respect to its contractual obligations hereunder and performance thereof, it will not claim immunity on the grounds of sovereignty or similar grounds with respect to itself or its revenues or assets from (a) suit, (b) jurisdiction of court (including a court located outside the jurisdiction of its organization), (c) relief by way of injunction, order for specific performance or recovery of property, (d) attachment of assets, or (e) execution or enforcement of any judgment.

E. If the appropriate box is checked on the Cover Sheet, as an alternative to selecting one of the options under Section 8.3, the Parties agree to add the following section to Article Three:

Section 3.6 Governmental Entity or Public Power System Security. With respect to each Transaction, Governmental Entity or Public Power System shall either (i) have created and set aside a Special Fund or (ii) upon execution of this Master Agreement and prior to the commencement of each subsequent fiscal year of Governmental Entity or Public Power System during any Delivery Period, have obtained all necessary budgetary approvals and certifications for payment of all of its obligations under this Master Agreement for such fiscal year; any breach of this provision shall be deemed to have arisen during a fiscal period of Governmental Entity or Public Power System for which budgetary approval or certification of its obligations under this Master Agreement is in effect and, notwithstanding anything to the contrary in Article Four, an Early Termination Date shall automatically and without further notice occur hereunder as of such date wherein Governmental Entity or Public Power System shall be treated as the Defaulting Party. Governmental Entity or Public Power System shall have allocated to the Special Fund or its general funds a revenue base that is adequate to cover Public Power System's payment obligations hereunder throughout the entire Delivery Period.

F. If the appropriate box is checked on the Cover Sheet, the Parties agree to add the following section to Article Eight:

Section 8.4 Governmental Security. As security for payment and performance of Public Power System's obligations hereunder, Public Power System hereby pledges, sets over, assigns and grants to the other Party a security interest in all of Public Power System's right, title and interest in and to [specify collateral].

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

G. The Parties agree to add the following sentence at the end of Section 10.6 - Governing Law:

> NOTWITHSTANDING THE FOREGOING, IN RESPECT OF THE APPLICABILITY OF THE ACT AS HEREIN PROVIDED, THE LAWS OF THE STATE OF _____[2] SHALL APPLY.

[2] Insert relevant state for Governmental Entity or Public Power System.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

SCHEDULE P: PRODUCTS AND RELATED DEFINITIONS

"Ancillary Services" means any of the services identified by a Transmission Provider in its transmission tariff as "ancillary services" including, but not limited to, regulation and frequency response, energy imbalance, operating reserve-spinning and operating reserve-supplemental, as may be specified in the Transaction.

"Capacity" has the meaning specified in the Transaction.

"Capacity Price" means the price, as set by PJM (unless defined or adjusted by Party B), that aligns with a specific PJM planning year spanning June through May, typically comprised of a Base Residual Auction (BRA) and up to three Incremental Auctions for which a price for Capacity is specific to a utility zone.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in megawatt hours.

"Energy Price" means the fixed $/MWh value for which Party A is compensated by Party B for supply rendered in association with the contract terms. This value shall be used in reference to either Fixed Price Load Following Full Requirements (FPFR) contracts or Around-the-Clock Block (ATC Block) supply contracts. For FPFR contracts, this value shall be inclusive of energy, capacity, transmission (other than NMB charges and credits which are the responsibility of Party B), ancillary services, and Alternative Energy Credits for compliance with the AEPS Act, associated transmission system losses, congestion management costs, and other such products and services that are required. In the event a Capacity Price is not available or otherwise final, Party B will supply Party A with guidance on the Capacity Price to be used. This newly defined Capacity Price will also be used in bill between Party A and Party B. For ATC Block contracts, this value shall be inclusive of energy only.

"Firm (LD)" means, with respect to a Transaction, that either Party shall be relieved of its obligations to sell and deliver or purchase and receive without liability only to the extent that, and for the period during which, such performance is prevented by Force Majeure. In the absence of Force Majeure, the Party to which performance is owed shall be entitled to receive from the Party which failed to deliver/receive an amount determined pursuant to Article Four.

"Firm Transmission Contingent - Contract Path" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product in the case of the Seller from the generation source to the Delivery Point or in the case of the Buyer from the Delivery Point to the ultimate sink, and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This contingency shall excuse performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

"Firm Transmission Contingent - Delivery Point" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission to the Delivery Point (in the case of Seller) or from the Delivery Point (in the case of Buyer) for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product, in the case of the Seller, to be delivered to the Delivery Point or, in the case of Buyer, to be received at the Delivery Point and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This transmission contingency excuses performance for the duration of the interruption or curtailment, notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary. Interruptions or curtailments of transmission other than the transmission either immediately to or from the Delivery Point shall not excuse performance

"Firm (No Force Majeure)" means, with respect to a Transaction, that if either Party fails to perform its obligation to sell and deliver or purchase and receive the Product, the Party to which performance is owed shall be entitled to receive from the Party which failed to perform an amount determined pursuant to Article Four. Force Majeure shall not excuse performance of a Firm (No Force Majeure) Transaction.

"Into _____ (the "Receiving Transmission Provider"), Seller's Daily Choice" means that, in accordance with the provisions set forth below, (1) the Product shall be scheduled and delivered to an interconnection or interface ("Interface") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which Interface, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area; and (2) Seller has the right on a daily prescheduled basis to designate the Interface where the Product shall be delivered. An "Into" Product shall be subject to the following provisions:

1. Prescheduling and Notification. Subject to the provisions of Section 6, not later than the prescheduling deadline of 11:00 a.m. CPT on the Business Day before the next delivery day or as otherwise agreed to by Buyer and Seller, Seller shall notify Buyer ("Seller's Notification") of Seller's immediate upstream counterparty and the Interface (the "Designated Interface") where Seller shall deliver the Product for the next delivery day, and Buyer shall notify Seller of Buyer's immediate downstream counterparty.

2. Availability of "Firm Transmission" to Buyer at Designated Interface; "Timely Request for Transmission," "ADI" and "Available Transmission." In determining availability to Buyer of next-day firm transmission ("Firm Transmission") from the Designated Interface, a "Timely Request for Transmission" shall mean a properly completed request for Firm Transmission made by Buyer in accordance with the controlling tariff procedures, which request shall be submitted to the Receiving Transmission Provider no later than 30 minutes after delivery of Seller's Notification, provided, however, if the Receiving Transmission Provider is not accepting requests for Firm Transmission at the time of Seller's Notification, then such request by Buyer shall be made within 30 minutes of the time when the Receiving Transmission Provider first opens thereafter for purposes of accepting requests for Firm Transmission.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

Pursuant to the terms hereof, delivery of the Product may under certain circumstances be redesignated to occur at an Interface other than the Designated Interface (any such alternate designated interface, an "ADI") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which ADI, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area using either firm or non-firm transmission, as available on a day-ahead or hourly basis (individually or collectively referred to as "Available Transmission") within the Receiving Transmission Provider's transmission system.

3. Rights of Buyer and Seller Depending Upon Availability of/Timely Request for Firm Transmission.

A. Timely Request for Firm Transmission made by Buyer, Accepted by the Receiving Transmission Provider and Purchased by Buyer. If a Timely Request for Firm Transmission is made by Buyer and is accepted by the Receiving Transmission Provider and Buyer purchases such Firm Transmission, then Seller shall deliver and Buyer shall receive the Product at the Designated Interface.

i. If the Firm Transmission purchased by Buyer within the Receiving Transmission Provider's transmission system from the Designated Interface ceases to be available to Buyer for any reason, or if Seller is unable to deliver the Product at the Designated Interface for any reason except Buyer's non-performance, then at Seller's choice from among the following, Seller shall: (a) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, require Buyer to purchase such Firm Transmission from such ADI, and schedule and deliver the affected portion of the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, or (b) require Buyer to purchase non-firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by Seller, or (c) to the extent firm transmission is available on an hourly basis, require Buyer to purchase firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of such hourly firm transmission from the Designated Interface or an ADI designated by Seller.

ii. If the Available Transmission utilized by Buyer as required by Seller pursuant to Section 3A(i) ceases to be available to Buyer for any reason, then Seller shall again have those alternatives stated in Section 3A(i) in order to satisfy its obligations.

iii. Seller's obligation to schedule and deliver the Product at an ADI is subject to Buyer's obligation referenced in Section 4B to cooperate reasonably therewith. If Buyer and Seller cannot complete the scheduling and/or delivery at an ADI, then Buyer shall be deemed to have satisfied its receipt obligations to Seller and Seller shall be deemed to have failed its delivery obligations to Buyer,

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

and Seller shall be liable to Buyer for amounts determined pursuant to Article Four.

iv. In each instance in which Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI pursuant to Sections 3A(i) or (ii), and Firm Transmission had been purchased by both Seller and Buyer into and within the Receiving Transmission Provider's transmission system as to the scheduled delivery which could not be completed as a result of the interruption or curtailment of such Firm Transmission, Buyer and Seller shall bear their respective transmission expenses and/or associated congestion charges incurred in connection with efforts to complete delivery by such alternative scheduling and delivery arrangements. In any instance except as set forth in the immediately preceding sentence, Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI under Sections 3A(i) or (ii), Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with such alternative scheduling arrangements.

B. Timely Request for Firm Transmission Made by Buyer but Rejected by the Receiving Transmission Provider. If Buyer's Timely Request for Firm Transmission is rejected by the Receiving Transmission Provider because of unavailability of Firm Transmission from the Designated Interface, then Buyer shall notify Seller within 15 minutes after receipt of the Receiving Transmission Provider's notice of rejection ("Buyer's Rejection Notice"). If Buyer timely notifies Seller of such unavailability of Firm Transmission from the Designated Interface, then Seller shall be obligated either (1) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, to require Buyer to purchase (at Buyer's own expense) such Firm Transmission from such ADI and schedule and deliver the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, and thereafter the provisions in Section 3A shall apply, or (2) to require Buyer to purchase (at Buyer's own expense) non-firm transmission, and schedule and deliver the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by the Seller, in which case Seller shall bear the risk of interruption or curtailment of the non-firm transmission; provided, however, that if the non-firm transmission is interrupted or curtailed or if Seller is unable to deliver the Product for any reason, Seller shall have the right to schedule and deliver the Product to another ADI in order to satisfy its delivery obligations, in which case Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with Seller's inability to deliver the Product as originally prescheduled. If Buyer fails to timely notify Seller of the unavailability of Firm Transmission, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface, and the provisions of Section 3D shall apply.

C. Timely Request for Firm Transmission Made by Buyer, Accepted by the Receiving Transmission Provider and not Purchased by Buyer. If Buyer's Timely Request for Firm Transmission is accepted by the Receiving Transmission Provider but Buyer elects to purchase non-firm transmission rather than Firm Transmission to take

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

delivery of the Product, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

D. No Timely Request for Firm Transmission Made by Buyer, or Buyer Fails to Timely Send Buyer's Rejection Notice. If Buyer fails to make a Timely Request for Firm Transmission or Buyer fails to timely deliver Buyer's Rejection Notice, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

4. Transmission.

A. Seller's Responsibilities. Seller shall be responsible for transmission required to deliver the Product to the Designated Interface or ADI, as the case may be. It is expressly agreed that Seller is not required to utilize Firm Transmission for its delivery obligations hereunder, and Seller shall bear the risk of utilizing non-firm transmission. If Seller's scheduled delivery to Buyer is interrupted as a result of Buyer's attempted transmission of the Product beyond the Receiving Transmission Provider's system border, then Seller will be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for damages pursuant to Article Four.

B. Buyer's Responsibilities. Buyer shall be responsible for transmission required to receive and transmit the Product at and from the Designated Interface or ADI, as the case may be, and except as specifically provided in Section 3A and 3B, shall be responsible for any costs associated with transmission therefrom. If Seller is attempting to complete the designation of an ADI as a result of Seller's rights and obligations hereunder, Buyer shall co-operate reasonably with Seller in order to effect such alternate designation.

5. Force Majeure. An "Into" Product shall be subject to the "Force Majeure" provisions in Section 1.23.

6. Multiple Parties in Delivery Chain Involving a Designated Interface. Seller and Buyer recognize that there may be multiple parties involved in the delivery and receipt of the Product at the Designated Interface or ADI to the extent that (1) Seller may be purchasing the Product from a succession of other sellers ("Other Sellers"), the first of which Other Sellers shall be causing the Product to be generated from a source ("Source Seller") and/or (2) Buyer may be selling the Product to a succession of other buyers ("Other Buyers"), the last of which Other Buyers shall be using the Product to serve its energy needs ("Sink Buyer"). Seller and Buyer

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

further recognize that in certain Transactions neither Seller nor Buyer may originate the decision as to either (a) the original identification of the Designated Interface or ADI (which designation may be made by the Source Seller) or (b) the Timely Request for Firm Transmission or the purchase of other Available Transmission (which request may be made by the Sink Buyer). Accordingly, Seller and Buyer agree as follows:

A. If Seller is not the Source Seller, then Seller shall notify Buyer of the Designated Interface promptly after Seller is notified thereof by the Other Seller with whom Seller has a contractual relationship, but in no event may such designation of the Designated Interface be later than the prescheduling deadline pertaining to the Transaction between Buyer and Seller pursuant to Section 1.

B. If Buyer is not the Sink Buyer, then Buyer shall notify the Other Buyer with whom Buyer has a contractual relationship of the Designated Interface promptly after Seller notifies Buyer thereof, with the intent being that the party bearing actual responsibility to secure transmission shall have up to 30 minutes after receipt of the Designated Interface to submit its Timely Request for Firm Transmission.

C. Seller and Buyer each agree that any other communications or actions required to be given or made in connection with this "Into Product" (including without limitation, information relating to an ADI) shall be made or taken promptly after receipt of the relevant information from the Other Sellers and Other Buyers, as the case may be.

D. Seller and Buyer each agree that in certain Transactions time is of the essence and it may be desirable to provide necessary information to Other Sellers and Other Buyers in order to complete the scheduling and delivery of the Product. Accordingly, Seller and Buyer agree that each has the right, but not the obligation, to provide information at its own risk to Other Sellers and Other Buyers, as the case may be, in order to effect the prescheduling, scheduling and delivery of the Product

"Native Load" means the demand imposed on an electric utility or an entity by the requirements of retail customers located within a franchised service territory that the electric utility or entity has statutory obligation to serve.

"Non-Firm" means, with respect to a Transaction, that delivery or receipt of the Product may be interrupted for any reason or for no reason, without liability on the part of either Party.

"Non-market-based Transmission Services" or "NMB" means both charges and credits associated with Network Integration Transmission Services ("NITS"), Transmission Enhancement, Expansion Cost Recovery, Non-Firm Point-to-Point Transmission Services, Regional Transmission Expansion Plan ("RTEP"), and Generation Deactivation, with the definitions ascribed to them in the PJM Agreements.

"System Firm" means that the Product will be supplied from the owned or controlled generation or pre-existing purchased power assets of the system specified in the Transaction (the "System") with non-firm transmission to and from the Delivery Point, unless a different Transmission Contingency is specified in a Transaction. Seller's failure to deliver shall be

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

excused: (i) by an event or circumstance which prevents Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Seller; (ii) by Buyer's failure to perform; (iii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on, the System; (iv) to the extent the System or the control area or reliability council within which the System operates declares an emergency condition, as determined in the system's, or the control area's, or reliability council's reasonable judgment; or (v) by the interruption or curtailment of transmission to the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Seller's performance. Buyer's failure to receive shall be excused (i) by Force Majeure; (ii) by Seller's failure to perform, or (iii) by the interruption or curtailment of transmission from the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Buyer's performance. In any of such events, neither party shall be liable to the other for any damages, including any amounts determined pursuant to Article Four.

"Transmission Contingent" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Seller's proposed generating source to the Buyer's proposed ultimate sink, regardless of whether transmission, if any, that such Party is attempting to secure and/or has purchased for the Product is firm or non-firm. If the transmission (whether firm or non-firm) that Seller or Buyer is attempting to secure is from source to sink is unavailable, this contingency excuses performance for the entire Transaction. If the transmission (whether firm or non-firm) that Seller or Buyer has secured from source to sink is interrupted or curtailed for any reason, this contingency excuses performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Article 1.23 to the contrary.

"Unit Firm" means, with respect to a Transaction, that the Product subject to the Transaction is intended to be supplied from a generation asset or assets specified in the Transaction. Seller's failure to deliver under a "Unit Firm" Transaction shall be excused: (i) if the specified generation asset(s) are unavailable as a result of a Forced Outage (as defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines) or (ii) by an event or circumstance that affects the specified generation asset(s) so as to prevent Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, and which is not within the reasonable control of, or the result of the negligence of, the Seller or (iii) by Buyer's failure to perform. In any of such events, Seller shall not be liable to Buyer for any damages, including any amounts determined pursuant to Article Four.

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

EXHIBIT A

MASTER POWER PURCHASE AND SALE AGREEMENT
CONFIRMATION LETTER

This confirmation letter shall confirm the Transaction agreed to on _____, ___ between _____ ("Party A") and _____ ("Party B") regarding the sale/purchase of the Product under the terms and conditions as follows:

Seller: _____

Buyer: _____

Product:

[] Into _____, Seller's Daily Choice

[] Firm (LD)

[] Firm (No Force Majeure)

[] System Firm

(Specify System: _____)

[] Unit Firm

(Specify Unit(s): _____)

[] Other _____

[] Transmission Contingency (If not marked, no transmission contingency)

[]	FT-Contract Path Contingency	[]	Seller	[]	Buyer
[]	FT-Delivery Point Contingency	[]	Seller	[]	Buyer
[]	Transmission Contingent	[]	Seller	[]	Buyer
[]	Other transmission contingency				

(Specify: _____)

Contract Quantity: _____

Delivery Point: _____

Contract Price:

Energy Price: _____

Other Charges: _____

©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

Delivery Period: _____

Special Conditions: _____

Scheduling: _____

Option Buyer: _____

Option Seller: _____

Type of Option: _____

Strike Price: _____

Premium: _____

Exercise Period: _____

This confirmation letter is being provided pursuant to and in accordance with the Master Power Purchase and Sale Agreement dated _____ (the "Master Agreement") between Party A and Party B, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

[Party A]	UGI Utilities, Inc.
Name: _____	Name: _____
Title: _____	Title: _____
Phone No: _____	Phone No: _____
Fax: _____	Fax: _____

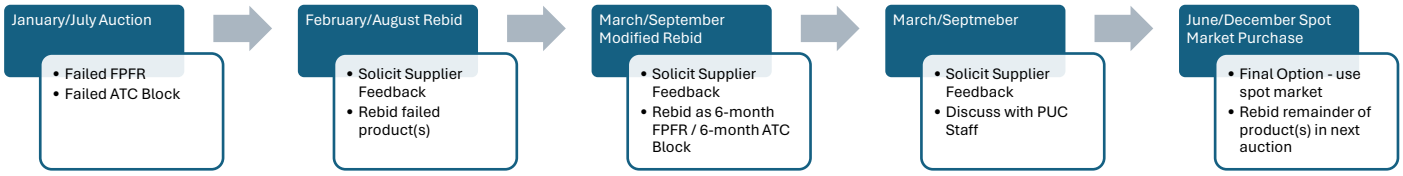
Version 2.1 (modified 4/25/00)
©COPYRIGHT 2000 by the Edison Electric Institute and National Energy Marketers Association

ALL RIGHTS RESERVED UNDER U.S. AND FOREIGN LAW, TREATIES AND CONVENTIONS
AUTOMATIC LICENSE – PERMISSION OF THE COPYRIGHT OWNERS IS GRANTED FOR REPRODUCTION BY DOWNLOADING FROM A COMPUTER AND PRINTING ELECTRONIC COPIES OF THE WORK. NO AUTHORIZED COPY MAY BE SOLD. THE INDUSTRY IS ENCOURAGED TO USE THIS MASTER POWER PURCHASE AND SALE AGREEMENT IN ITS TRANSACTIONS. ATTRIBUTION TO THE COPYRIGHT OWNERS IS REQUESTED.

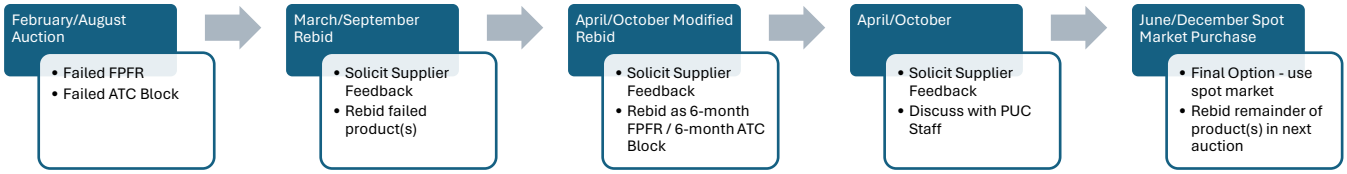
EXHIBIT SCF-8

CONTINGENCY OPTIONS

(1) Following a failed product auction in **January or July** (maximum gap between failed auction and supply start):



(2) Following a failed product auction in **February or August** (gap between failed auction and supply start is 2-3 months):



(3) Following a failed product auction in **March or September** (gap between failed auction and supply start is 2 or less months):

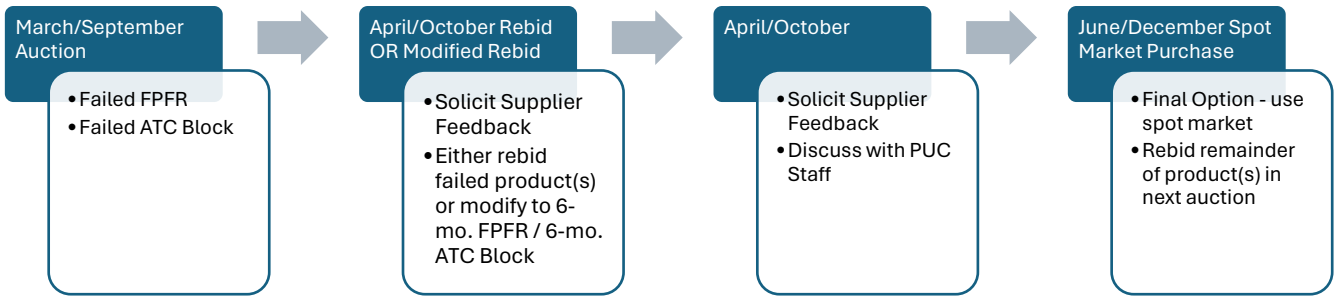


Exhibit SCF - 9

UGI Utilities, Inc. – Electric Division
Default Service Plan V – Request for Proposal
[AUCTION OPEN DATE - Month Day, Year]

1. UGI Utilities, Inc – Electric Division ("UGI") is seeking quotes for supplying renewable energy certificates to meet its Alternative Energy Portfolio Standard ("AEPS") requirements. Bids must conform to the standards approved by the Pennsylvania Public Utility Commission ("PUC") in UGI's Default Service Supply filing (P-2024-_____ and G-2024-_____)

2. All submitted bids must remain open until UGI receives approval or rejection of bid results from the Pennsylvania PUC.
   a. Window is explicitly between: [*Bid submission date*] through or before [*Date of PA PUC Approval*]

3. All bids must be submitted:
   a. By e-mail to ugirfp@ugi.com
   b. On bid Date: [Month Date, Year]
   c. Within the following bid window hours: [HOUR START] and no later than **[HOUR END].**

4. **Bids received that have a time stamp later than [HOUR END] will not be considered.**
   a. UGI or the UGI Auction Manager will confirm receipt with submitting Bidder within 30 minutes of receipt per the contact information provided on the Bid Submission Form

5. Bidders may provide bids for one or more Tier types as desired. Each bid must be priced separately. For determining the winning bidder, each bid will be evaluated and awarded individually. Bids are for the full quantity of Alternative Energy Credits ("AEC") as defined in the table below. AEC submissions for quantities below the Quantity defined in the table below may be evaluated and/or selected at UGI's sole discretion – including but not limited to an event of under-bid for a given Tier Type.

6. Only credits certified by Pennsylvania as defined within the PJM Generation Attribute Tracking System ("PJM GATS") will be accepted. The Certification Number must be included for existing projects to verify that they meet the qualified criteria for compliance with the Pennsylvania AEPS Act.

7. The winning bidder must have a valid account through the PJM Environmental Information Systems, Inc.'s ("PJM-EIS") GATS for the facilitation of AEC transfers. GATS is the Commission designated credit registry.

8. Credits must be transferred to UGI's PJM GATS account within 10 business days following the execution of the contract. Payments will be made commensurate with the quantity of AECs transferred.

9. The Renewable Energy Certificate Purchase and Sale Agreement between UGI and the counterparty will control all transactions completed under this RFP. A draft of this agreement is posted on UGI's website at:

   [Insert Link]

10. All bids will be ranked based solely upon price, with the lowest priced bid being awarded the contract. In the event two or more bids are received that contain identical prices, tied bidders will be contacted to provide a best-and-final price, which may not be higher than the price originally bid in the solicitation. If this method does not break the tie, the winning bidder will be chosen at random by the UGI Auction Manager.

11. All bids must be submitted in U.S. dollars.

12. A Bid Response Form is attached. Bids must be submitted on a form similar to the attached to be considered by UGI.

13. Solar AECs and Tier II AECs must adhere to updated regulations concerning geographic eligibility.

14. All bidder inquiries should be directed to UGI at: ugirfp@ugi.com

UGI is Seeking to Purchase the Following AECs

Tier Type	Quantity	Allowed Vintage by Compliance Year		% of AECs Allowed by Vintage
Tier I (Non-Solar)	[Enter]	June [Year] through May [Year]	Y	[%]
		June [Year] through May [Year]	Y	
		June [Year] through May [Year]	Y	[%]
Tier II	[Enter]	June [Year] through May [Year]	Y	[%]
		June [Year] through May [Year]	Y	
		June [Year] through May [Year]	Y	[%]
Solar	[Enter]	June [Year] through May [Year]	Y	[%]
		June [Year] through May [Year]	Y	
		June [Year] through May [Year]	Y	[%]

UGI Utilities, Inc. – Electric Division
Default Service Plan V – Request for Proposal Response Form
[BID DATE - Month Day, Year]

This bid is submitted in response to UGI's Request for Proposal dated [BID DATE - Month Day, Year].

Supplier Name _____

Primary Contact Phone _____

Primary Contact E-mail _____

Supply Type Pennsylvania Alternative Energy Credits

Vintage

- June [Year] through May [Year] – at least [%] or [Quantity]
- June [Year] through May [Year] – remaining quantity following adherence to above vintage requirement or [%]

Tier Type	Quantity	Bid Price* ($)
Tier I	[FILL]	$
Tier II	[FILL]	$
Solar	[FILL]	$

Place an "X**" if no bid is being placed for the AEC Tier Type. Please **DO NOT** place a zero (0).*

All bids must be submitted by e-mail to ugirfp@ugi.com by [Month Day Year]**, within the bid window of [HOUR START] to [HOUR END].**

Bids must remain open until the close of the business (5:00 p.m. E.T) on [PUC APPROVAL DATE - Month Day, Year]. Bidders must execute the Renewable Energy Certificate Purchase and Sales Agreement without modification upon winning bids within two business days following PUC Approval.

[Date]

Dear Sir or Madam,

RE: Request for Proposal to Purchase Alternative Energy Credits

UGI Utilities – Electric Division ("UGI") is seeking to purchase renewable energy certificates to fulfill a portion of its Alternative Energy Portfolio Standard ("AEPS") requirements. The Request for Proposals ("RFP") and bidding details are attached.

UGI is using a competitive bidding process to obtain Alternative Energy Credits ("AECs") to fulfill its obligations pursuant to Pennsylvania's Alternative Energy Standards Act. This RFP is issued to purchase AECs necessary to meet the AEPS obligation established under UGI's approved petition for a Default Service Supply Plan in Docket No. P-2024-_____ and G-2024-_____, to be effective [Date]. This plan established the mechanism by which UGI will procure AECs through a competitive solicitation process. Therefore, UGI is issuing this RFP to secure certain quantities of AECs as specified below. All acquisitions made through RFP's will be monitored by a third party, [Auction Manager], to ensure a fair and unbiased process. Shown below is the maximum quantity of AECs UGI is seeking to purchase. UGI reserves the right to purchase less than the maximum amount.

Tier Type	**Maximum Quantity to Purchase**	**Allowed Vintage by Compliance Year**		**Maximum Quantity to Purchase**
Tier I (Non-Solar)	[Enter]	June [Year] through May [Year]	Y/N	[%]
		June [Year] through May [Year]	Y/N	
		June [Year] through May [Year]	Y/N	[%]
Tier II	[Enter]	June [Year] through May [Year]	Y/N	[%]
		June [Year] through May [Year]	Y/N	
		June [Year] through May [Year]	Y/N	[%]
Solar	[Enter]	June [Year] through May [Year]	Y/N	[%]
		June [Year] through May [Year]	Y/N	
		June [Year] through May [Year]	Y/N	[%]

The schedule below provides key dates and times associated with this RFP.

RFP Schedule

[Date]	Notice of RFP sent to potential suppliers.
[Date]	Bidder Information Session
[Date] (1:00 p.m. E.T.)	RFP Conference Call with all interested parties Call-in Number – TBD Code – TBD
[Date] (12:00 p.m. E.T.)	Last day to submit questions.
[Date] (12:00 p.m. E.T.)	RFP responses due to UGI/[Auction Manager].
[Date] (1:00 p.m. E.T.)	Winning bidders selected by UGI/[Auction Manager], and verbally notified by UGI/[Auction Manager] of bid status
[Date] (2:00 p.m. E.T.)	Results of solicitation sent to Pennsylvania PUC.
[Date+1]	Pennsylvania PUC approves results of RFP.
[Date+1]Close of Business	UGI/[Auction Manager] verbally notifies winning bidders.

Responses to this RFP must be submitted through e-mail to ugirfp@ugi.com by **[Date] at 12:00 p.m. E.T.** Through this e-mail address, both UGI and [Auction Manager] will receive your bid and will independently evaluate the responses and determine the winning bidders. Bids that have a time stamp after 12:00 p.m. will not be considered.

Questions pertaining to this RFP must be received before 12:00 p.m. on [Date]. Questions and Responses will be posted on UGI's website which can be found at:

[Insert Link]

Once the winning bidders are determined, the results must be forwarded to the PUC, which will either accept or reject the winning bids. Therefore, all bids must remain open until the end of the first business day following submission. While UGI cannot dictate a timeline to the PUC, it is hoped the PUC will approve the results of the RFP within one (1) business day of the bid deadline. Immediately following the PUC's decision, UGI/[Auction Manager] will then contact the winning bidders by telephone to confirm the transaction(s).

By providing a bid, interested parties agree to execute the provided Renewable Energy Certificate Purchase and Sale Agreement contract without any modifications. UGI will require that this contract be executed upon awarding the bids.

If the winning bidder fails to deliver the credits awarded to them, UGI will purchase replacement credits and bill the defaulting party for any additional costs incurred.

The criterion for selecting winning bids will be based on price and the generation period. In the event of identical winning bids, credits will be awarded to the winning bidders on a pro rata basis.

Thank you,

UGI

Exhibit SCF-10

Transaction Confirmation

Date: [Insert]

Re: Alternative Energy Credits

This Transaction Confirmation, together with the attached General Terms and Conditions, constitute the Purchase and Sale Contract ("Contract") between [Insert Seller Name], as Seller, and UGI Utilities, Inc. – Electric Division, as Buyer (together, the "Parties") based on the terms set forth herein.

Seller: [Insert Seller Name]

Buyer: UGI Utilities, Inc.

Product: Alternative energy credits ("AECs") as defined as of the date first set forth above in Title 73, Chapter 18F, Alternative Energy Portfolio Standards Act, Sections 1648.1 though 1648.8 of the Pennsylvania Statutes (the "AEPS Act"). The AEC's will be administered and transferred, under the terms and conditions hereof, by the Environmental Information Services of PJM Interconnection, LLC ("PJM-EIS") Generation Attribute Tracking System ("GATS") in connection with its obligations hereunder at such time as Seller transfers to Buyer, through GATS, the Quantity of AECs recognized as meeting Pennsylvania AEPS Act requirements.

Facilities: [Insert As Appropriate]

Transaction Type: [Insert As Appropriate]

Tier Type: [Insert]

Price: [Insert]

Vintage Requirements: [QTY] June [Year] through May [Year]; [QTY] June [Year] through May [Year]

Delivery and Payment: The Product will be delivered and paid for under the following terms:

(i) AECs to be delivered by _____.
(ii) Within __ Business Days of Buyer's receipt of the Product, Buyer will pay to Seller an amount equal to the product of (i) the Quantity, and (ii) the Price.

Delivery will be effectuated through PJM-EIS using GATS. Title to the Product and risk of loss will transfer at such time as PJM-EIS recognizes the transfer of the Product to Buyer through GATS.

Payment: Payment by Buyer to Seller shall be made to the following account:

Wire Instructions:
_____
_____

Term: This Contract will terminate after the Quantity of the Product has been delivered and paid for under the terms hereof. Sections 1, 4, 7 and 8 of the General Terms and Conditions will survive termination to the extent necessary for the Parties to enforce their rights hereunder.

Special Conditions:

1. If a fee is assessed by the Pennsylvania Public Utility Commission (or any other governmental entity) in connection with the transfer of certification of the AECS, as

between the Parties Buyer will be responsible for such amounts. Buyer will indemnify, defend and hold harmless Seller from and against any such fees for which Buyer is responsible.

2. The General Terms and Conditions attached hereto are included herein for all purposes and are an integral part of this Contract. Provided, that, to the extent there is any conflict between a provision in the General Terms and Conditions and this Transaction Confirmation, the terms of the Transaction Confirmation shall control. This Contract sets forth the entire agreement between the Parties with respect to the AEC purchase identified in this document superseding any and all contemporaneous or prior conversations, memoranda, agreements (oral or written) or other communication with respect to its subject matter between the Parties or any of their respective agents. There are no third party beneficiaries to this Contract. This Contract may not be terminated (other than as provided in this Contract) or changed except by a writing signed by both Parties. No right, obligation or provision of this Contract shall be deemed waived unless such waiver is evidenced by a writing signed by the Party charged with the waiver and any such waiver shall be strictly limited to the express terms of such writing. No representations or warranties have been given other than those expressly stated in this Contract to induce either Party to enter into this Contract.

IN WITNESS WHEREOF, and intending to be legally bound, the Parties have executed this Contract by the undersigned duly authorized representatives as of the date of this Contract.

_____		UGI Utilities, Inc. – Electric Division	
Signature:	_____	Signature:	_____
Name:	_____	Name:	_____
Title:	_____	Title:	_____
Date:	_____	Date:	_____

GENERAL TERMS AND CONDITIONS

1. Events of Default and Remedies:

1.1 An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

(a) the failure to make, when due, any payment required pursuant to this Contract if such failure is not remedied within three (3) business days after written notice;

(b) the failure by Seller to deliver to Buyer, when required pursuant to this Contract, the AECs if such failure is not remedied within three (3) business days after written notice;

(c) any representation of warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;

(d) a material breach of a covenant or obligation (other than as separately provided for in this Section 1.1) set forth in this Contract not cured within five (5) days following written noticed thereof;

(e) such Party:

(i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it and not discharged within thirty (30) days,

(ii) makes an assignment or any general arrangement for the benefit of creditors,

(iii) otherwise becomes bankrupt or insolvent (however evidenced),

(iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or

(v) is generally unable to pay its debts as they fall due.

1.2 If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party shall have the right to (i) suspend performance, (ii) withhold any payments due to the Defaulting Party under this Contract, and (iii) terminate this Contract on two (2) business days prior notice to accelerate all amounts owing between the Parties and to liquidate and recover its damages or enforce specific performance resulting from such Event of Default.

2. No Waiver. No waiver at any time by any Party hereto of its rights with respect to the other Party or with respect to any matter arising in connection with the Contract shall be considered a waiver with respect to any subsequent default or matter.

3. Assignment. Neither Party shall assign this Contract without the prior written consent of the other Party, which consent may not be unreasonably withheld; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer or assign this Contract to an affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (ii) transfer or assign this Contract to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request, and further provided that with respect to (ii) above, the assigning Party ("Assignor") shall be relieved of liability hereunder so long as the benefits of any Guaranty provided by the Assignor extends to the obligations of the Assignee pursuant to documentation or amendment reasonably satisfactory to the other Party.

4. Taxes and Indemnity. Seller will be responsible for any taxes imposed by any government authority on the creation, ownership, or transfer of the Product under this contract up to and including the time and place at which title transfers. Buyer will be responsible for any taxes imposed by any government authority on the receipt of ownership of the Product after the time and place at which title transfers. For avoidance of doubt, the foregoing two sentences will not apply, however, to the assessment of any fee as contemplated by Section 2 of the Special Conditions in the Transaction Confirmation. Each Party will indemnify, defend and hold harmless the other Party from and against any claims or demands made by others arising from or out of any event, circumstance, act or incident first occurring or existing during the period when title to the Product is vested in such Party as provided herein, except to the extent arising from such Party's own gross negligence or willful misconduct. Each Party will indemnify, defend and hold harmless the other Party against any taxes for which such Party is responsible as provided herein.

5. Representations.

5.1 From the date of entering into this Contract and throughout the Term of this Contract, the Parties each warrant and covenant as follows:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(b) it has all regulatory authorizations necessary for it to legally perform its obligations under this Contract;

(c) it has the requisite authority to enter into and perform its respective obligations under the contract;

(d) the obligations hereunder are binding on it;

(e) it is not the subject of any bankruptcy proceeding or involved in litigation that would materially affect its ability to perform hereunder, except as provided for in any SEC Filing by it or any of its affiliates;

(f) the contract has been negotiated in the ordinary course of business, in good faith, for fair consideration on an arms length basis between Parties of equal sophistication and represents a bargained for exchange; and

(g) it has entered into this Contract in connection with the conduct of its business and it has the capacity and ability to perform its obligations hereunder.

6 Notices. All notices to _____ shall be given to:

_____
_____
_____

With additional Notices of an Event of Default or Potential Event of Default to:

_____
_____
_____

All notices to UGI Utilities, Inc. – Electric Division under the contract shall be given to:

[Insert Title]

Email: [Insert email] Phone: [Insert Phone]

With additional Notices of an Event of Default or Potential Event of Default to:

[Insert Title]

Email: [Insert email] Phone: [Insert Phone]

Except as otherwise expressly provided herein, all notices to the other Party under the Contract shall be in writing and shall be deemed effective upon receipt if received prior to 5:00 p.m., local time, on a business day, or on the next succeeding business day if otherwise.

7. Choice of Law. This contract will be governed by the laws of the state of Pennsylvania.

8. Waiver of Jury Trial. Each Party waives its respective right to any jury trial with respect to any litigation arising under, or in connection with this Contract.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division For Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029	:	Docket Nos. P-2024-3049343 G-2024-3049351

REBUTTAL TESTIMONY
OF
STAN C. FARYNIARZ

UGI ELECTRIC STATEMENT NO. 2-R

Dated: August 30, 2024

I. Introduction

Q. Please state your name and address.

A. My name is Stan C. Faryniarz. My business address is 370 Main Street, Suite 325, Worcester, MA 01608.

Q. By whom are you employed, and in what capacity?

A. I am employed by Daymark Energy Advisors as a Principal Consultant and Practice Area Lead. I am testifying on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") in this proceeding.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. My direct testimony, UGI Electric St. No. 2, was submitted on May 31, 2024, as Appendix C to the Petition.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the Office of Consumer Advocate ("OCA") witness Serhan Ogur's arguments related to the procurement plan for GSR-1 customers. I also respond to many of Penn Renewables, LLC ("Penn Renewables") witness James L. Crist, P.E.'s, arguments related to classifying GSR-2 customers based upon their system impact.

Q. Are you sponsoring any Exhibits with your rebuttal testimony?

A. Yes, I am sponsoring two Exhibits:

- Confidential Exhibit SCF-R1 – UGI response to OCA-I-5, including the Confidential Attachment.
- Confidential Exhibit SCF-R2 – Penn Renewables response to PR-I-5 including the Confidential Attachments.

Q. Do you have any additional comments concerning party testimony?

A. Yes. While not expanded upon further in my rebuttal testimony, OSBA witness Mr. Ewen reviewed UGI Electric's filing and did not object to the Company's approach. Specifically, Mr. Ewen states that the Company's proposed procurement strategy for GSR-1 customers is reasonable, as is the Company's proposed approach to procure residential and non-residential customers below the 100kW demand split through a combined procurement, then separating them into subgroups.[1]

II. GSR-1 Default Supply Procurement Mix

Q. Please summarize the Company's proposed procurement plan for GSR-1 customers.

A. UGI Electric has proposed implementing a combination of 12-month fixed price full requirements ("FPFR") load following products, 24-month block, around-the-clock ("ATC"), energy-only products, and continued contracting for the long-term Allegheny Energy Supply. The ATC Block products will ultimately amount to 20 MW in total following two solicitations – solicitation 1 and solicitation 3 – to create a laddered and layered product effect. The 12-month FPFR products will also be procured in a laddered

[1] OSBA Direct Testimony, p. 5 lines 19-24.

and layered fashion in the annual spring and fall solicitations for the entire GSR-1 supply less that of the ATC Block products and the Allegheny Energy Supply.

Q. Mr. Ogur indicates that your Direct Testimony about the GSR-1 procurement plan including spot purchases appears to be in error. (OCA St. No. 1, p. 8, lines 8-13.) Please respond.

A. In reviewing Mr. Ogur's testimony and conferring with the Company, I have concluded that Mr. Ogur's assertion concerning the way UGI Electric settles block and spot supply in the market is correct. Specifically, in the DSP IV Plan UGI Electric separately manages 25% of the GSR-1 load. This obligation is primarily met through use of the ATC and peak block contracts; however, in instances where the 25% load share differs from the amount of energy secured through block contracts, UGI Electric utilizes the spot market – purchasing necessary energy when load exceeds block supply or selling excess block energy when the load is below the block supply amount. In the Company's proposed DSP V Plan, there is no such obligation on the part of UGI Electric with the Company instead purchasing 20 MW of ATC Block, and the remaining load share being supplied through FPFR contracts with wholesale suppliers. Procuring energy in this fashion eliminates the need for UGI Electric to settle any GSR-1 supply through the spot market.

Q. What are the additional benefits of implementing UGI Electric's DSP V product mix?

A. The primary drivers behind the Company's proposed changes in products and procurement approach were a focus on reducing plan complexity, reducing risk and associated risk premium, reducing rate volatility, and improving competition. As discussed above, the

Company's product changes move away from spot market settlements and, therefore, aid in the reduction of rate volatility while also reducing the number of products comprising the GSR-1 supply mix.

The Company also proposed the following changes to improve supplier participation, reduce bid premiums, and improve supplier competition:

- Decreasing the number of products bid from four to two (including 24-month ATC Block and 12-month FPFR load following);
- Implementing 20 MW of firm and fixed 24-month ATC Block contracts;
- Increasing the load share assigned to 12-month FPFR contracts to approximately 60 MW;
- Maintaining complementary and diverse product mix through the use of 12-month FPFR load following contracts and 24-month ATC Block contracts – supporting supplier diversity;
- Implementing a 50% bid cap for the 12-month FPFR contracts to limit exposure to a single supplier; and
- Moving solicitations to earlier periods if the year to reduce conflict with peer utility solicitations and improve the time suppliers have to hedge supply before delivery begins (January/February and July/August).

UGI Electric's proposed portfolio moves away from 1-month block contracts to more stable 24-month ATC Block, reduces the magnitude of the use of the spot market for reconciliation, improves transparency to suppliers on the impact of ATC Block supply on overall load responsibility share, increases supplier tranche size for FPFR supply, aims to reduce supplier risk premiums otherwise inherent in 24-month FPFR contracts, improves

rate stability and pricing for customers, and reduces UGI Electric administrative and operational implementation time and complexity. These changes drive toward increased competition, reduced bid pricing, reduced costs, and improved rate stability.

Q. What does OCA witness Ogur propose with respect to the procurement plan for GSR-1 customers?

A. Mr. Ogur proposes that UGI Electric holistically modify its procurement plan to procure a series of 24-month FPFR load following contracts, each comprising 25% of the Company's GSR-1 default service supply, ultimately providing 100% of the GSR-1 supply obligation[2]. He caveats this approach with a recognition that its implementation requires a transitional period including 12-month and 18-month FPFR contracts, to create a layered and laddered product mix, with each solicitation following solicitation 1 seeking to procure 24-month FPFR contracts for 25% of the supply obligation.

Mr. Ogur supports the Company's proposal to implement contract overhang between DSP V and the future DSP VI plan.[3] He also supports the Company's continued use of a sealed-bid procurement methodology[4] and plan to maintain twice-per-year solicitations.[5] Further, Mr. Ogur seems to support UGI Electric's proposal to pull back non-market-based transmission service charges – relieving that responsibility, and price risk, from wholesale suppliers participating in its solicitations – by noting the Company's

[2] OCA Statement No. 1, p. 16, lines 8-13 and p. 17, lines 1-8.
[3] OCA Statement No. 1, p. 22, lines 21-23.
[4] OCA Statement No. 1, p 23, lines 10-12.
[5] OCA Statement No. 1, p. 16, lines 8-13 through p. 18 lines 1-2 – communicates the maintenance of twice-per-year procurements in the OCA's proposal and provides no indication of a change in the procurement frequency.

proposed change and using it as a complimentary support for the OCA's proposed move to 24-month FPFR contracts.[6]

Q. Why does Mr. Ogur propose 100% 24-month FPFR contracts?

A. Mr. Ogur provides three reasons for a move to 100% 24-month FPFR contracts. They include improved rate stability, reduced administrative and operational burden to UGI Electric, and reduction in the number of products lending to increases in the number of supply amount per tranche bid. He also asserts that the 24-month contract terms result in a greater overlap into the next default service plan – DSP VI – providing improved rate stability going forward.[7]

Q. Does the Company agree with Mr. Ogur's proposal?

A. No, the Company does not support the OCA's proposal to move the GSR-1 product mix to a 100% 24-month FPFR contract solution. UGI Electric's proposed product mix provides most of the benefits highlighted by Mr. Ogur in his support of the OCA proposal and includes additional benefits such as likely lower supplier risk premiums, a diversity of products that may entice more suppliers to bid (i.e., supplier diversity), and a greater tranche size for FPFR products.

First, Mr. Ogur's assertion surrounding the benefits of 24-month FPFR products on rate stability are accurate. However, this is mainly due to the term of the contract, not necessarily the nature of FPFR contracts. In the OCA's proposal, the procurement of 24-

[6] OCA Statement No. 1, p. 20, lines
[7] OCA Statement No. 1, p. 21, lines 19-24 and p. 22, lines 1-13.

month contracts in 25% increments or otherwise a 100% 24-month FPFR product mix, results in a relatively low amount of supply turn-over each Price-to-Compare ("PTC") period – 25% per term after the initial transitional procurement in the first solicitation. As such, the low turn-over results in moderate GSR-1 rate stability. However, the benefit draw is primarily a result of the 24-month term, not FPFR supply.

In UGI Electric's proposal, non-market-based transmission service charges are being pulled back to the Company and out of FPFR supply – a move supported by the OCA.[8] Further, the Company has detailed an approach to stabilize the risk of PJM Interconnection, LLC ("PJM") capacity in the event market-based prices are not established for the term being bid on in a given solicitation. With these changes, two of the three major risks to suppliers are reduced – incomplete capacity pricing and non-market-based transmission cost. The last risk-prone area to FPFR contracts is that of load variability, which requires contemplation – balancing the benefits of risk mitigation due to changing loads versus the cost for that mitigation inherent in bid prices.

The OCA's proposal fully relies upon relatively illiquid and high bid premium products through the 100% use of a longer-term 24-month FPFR contracts. Use of such contracts would create slightly more stable GSR-1 rates, but do so at the risk of moderately to substantively higher costs. UGI Electric proposes to utilize 24-month ATC Block contracts that secure firm, 24x7 energy-only supply – an approach that includes substantially less risk and, therefore, lower risk premiums while also gaining the majority of the rate stabilization benefits of a longer-term contract. Although this result does not achieve the same level of rate stability as the OCA proposal because it does not pursue a

[8] OCA Statement No. 1, p. 19, lines 19-25 through p. 20, lines 1-6.

100% 24-month contract supply mix, the Company's approach would adequately balance costs with benefits, increase product and supplier diversity, include a moderate level of market reflectivity, and draw from the success of the block product solicitations in DSP IV.

The OCA's approach also contends to reduce administrative and operational burdens, likely as a result of fewer products bid in the solicitation and a simplified settlement and scheduling process. However, I would contend that such process improvements and solicitation simplifications are relatively minor and associated savings are minimal. Program administrative costs have never been a driving contributor to UGI Electric's default service rate. Through the Company's DSP IV filing[9] the annual administrative expenses were forecast at $273,784, or well below 1% of the total plan costs.[10] Under UGI Electric's current proposal, costs are forecast to remain below 1% of total plan costs. While a simplified approach is likely to reduce some administrative activities, the Company has experienced few challenges in the implementation of any default service plan. Further, UGI Electric's proposed DSP V plan provides for a simplified product approach with standardized ATC Block products and reducing the total number of bid products from four to two.[11] Any administrative or operational efficiencies gained between UGI Electric's proposal and OCA's proposal are likely immaterial and should not influence the products being considered in DSP V.

9 UGI Electric DSP IV, Docket No. P-2020-3019907, UGI Electric Statement No. 2, Exhibit SFA-2.

10 Analysis based upon the 2022 GSR-1 rate filing with total costs of $52.6 million; however, 2023 and 2024 GSR-1 rate filings reported costs of $75.3 million and $67.9 million, respectively. Using these higher figures reduces the administrative cost share to approximately 0.34%.

11 UGI Electric DSP IV implemented 12-month and 24-month FPFR contracts along with ATC and Peak Block contracts; DSP V seeks to implement 12-month FPFR contracts and ATC Block contracts.

I also disagree with Mr. Ogur's claim that his proposal will result in greater supply per tranche. The UGI Electric proposal seeks to procure 24-months of 20 MW ATC Block supply, with the remaining supply obligation being met through two 12-month FPFR contracts, each 50% of the remaining load obligation following the removal of the ATC Block. Block supply is forecast to account for approximately 24% of the total default service supply obligation with the 12-month FPFR contracts comprising the remaining 76%, or 38% per contract. Compared to the OCA's proposal of 25% load share per tranche, the 12-month FPFR contracts result in a greater tranche size per contract, as discussed in more detail below, than those proposed in the OCA's recommendation for 24-month FPFR contracts.

There is one caveat that should be noted – the 24-month FPFR tranche size is expected to be greater than the two 10 MW ATC Block contracts in UGI Electric's proposal. I would contend that it was not UGI Electric's focus to improve the block contract size, which has proven competitive in the Company's DSP IV solicitations.[12] Instead, the Company's focus was on improving the FPFR product through improved supply stability and expanded tranche size.

Q. Mr. Ogur references the default supply plans of other EDCs in Pennsylvania as support for his proposal. (OCA St. No. 1, pp. 13-14.) Are these references relevant for UGI Electric?

A. The references to peer utility proposals and practices are helpful but not directly relevant. The review of peer proposals can give insight into the potential successes or challenges of different products, terms, and other conditions, which may provide UGI Electric with

[12] Reference response to OCA-I-5 and CONFIDENTIAL Attachment OCA-I-5.

beneficial insights into its own plan. Mr. Ogur highlights that all peer Pennsylvania utilities have incorporated a combination of 12-month and 24-month FPFR load following suppliers, with PPL Electric Utilities Corporation ("PPL Electric") also proposing the incorporation of 150MW 10-year ATC Block.

However, there are a few key considerations that Mr. Ogur fails to highlight in his comparisons relative to the OCA proposal: (1) no peer has proposed a 100% 24-month FPFR product mix, (2) UGI Electric's customer count and supply size is a magnitude smaller than that of Duquesne Light Company ("Duquesne"), PPL Electric, PECO Energy Company ("PECO"), or FirstEnergy Pennsylvania Electric Company ("FE PA") (formerly, Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power"), and West Penn Power Company ("West Penn")),[13] (3) UGI Electric's supply size and customer count are substantively greater than that of Citizens' Electric Company ("Citizens' Electric")[14] and Wellsboro Electric Company ("Wellsboro Electric"),[15] (4) and the larger peer utility customer classes do not combine the residential and small non-residential customers. These four considerations highlight that no peer utility – either plan or customer composition – is equivalent to that of UGI Electric. Therefore, only concepts can be gleaned from their plans.

[13] Duquesne has an estimated 600,000 customers (https://duquesnelight.com/company/about) , PPL Electric has an estimated 1.5 million customers, PECO has an estimated 1.6 million electric customers, and FE PA has approximately 2 million electric customers across its four rate districts (Met-Ed – 560,000; Penelec – 600,000; Penn Power – 160,000; and West Penn – 720,000).

[14] Citizens' Electric has an estimated 7,000 customers in its service territory per the Company Description in Docket No. A-110050 and its website: https://citizenselectric.com/about-us/

[15] Wellsboro Electric has an estimated 6,381 customers in its service territory per their website: https://wellsboroelectric.com/customer-service/faq/#:~:text=Wellsboro%20Electric%20Company%20provides%20electricity,customers%20in%20the%20Wellsboro%20area.

Q. How will UGI Electric's proposed procurement plan address Mr. Ogur's rate volatility concerns as compared to UGI Electric's current procurement methodology?

A. The overarching theme of Mr. Ogur's product approach was a need for rate stability. The UGI Electric DSP IV product mix creates rate variability through 25% monthly block and spot products, which has been alleviated in DSP V through the elimination of this product mix and replaced with 24-month ATC Block.

Q. Does UGI Electric's proposed plan address rate-related concerns beyond volatility?

A. Yes. As explained in summary above, UGI Electric's plan also seeks to increase supplier participation and resulting product competition and to reduce supplier risk premiums. As a result, the Company's plan is designed to address concerns beyond rate volatility by also focusing on lower rates and expanded competition to the benefit of customers.

Q. Please address Mr. Ogur's proposal to replace the 24-month block purchase with a 24-month FPFR contract. (OCA St. No. 1, p. 19.)

A. There are three considerations a move to a 24-month FPFR contracts fails to leverage – a concern around supplier participation and diversity found in block supply products, a lack of product diversity, and a higher likely risk premium. First, as provided by UGI Electric in response to OCA-I-5[16], over the past three years supplier participation has been substantially higher for block products than for the FPFR products bid. While this can be attributed to a number of different factors, an overarching consideration must be the perceived lower risk and greater attractiveness to block products as compared to 12 or 24-month FPFR products. As such, it is prudent to maintain this product type in the mix for

[16] Including CONFIDENTIAL Attachment OCA-I-5.

UGI Electric's DSP V to the level possible. Second, there is a risk to utilizing a single product type. Suppliers not interested in FPFR products, especially longer-term products could result in lower supplier participation and risk failed product auctions. Just as supplier diversity is important, so too is that of product diversity that entices suppliers and resulting competition for those products. Finally, as previously mentioned, FPFR products inherently have greater risk given the variability of the load and inclusion of product variables beyond their energy-only equivalent in block supply. As such, suppliers will include higher premiums, especially during market events, rapid changes in capacity market costs,[17] or overall instability. While risk premiums are likely included in the Company's 12-month FPFR products, the premiums are balanced by increasing the supply amount per tranche and limiting the term to 12-months. The OCA's proposal of 24-month FPFR contracts with a smaller tranche size, comparatively, results in a higher likely risk premium that will drive customer costs higher than otherwise necessary.

Q. Do you agree with Mr. Ogur's suggestion that UGI Electric will be able to easily procure 24-month FPFR contracts? (OCA St. No. 1, pp. 19-20.)

A. No, not necessarily. Mr. Ogur points to peer utility product mixes and their ability to secure supply; however, as mentioned previously in my testimony, most of those peer Pennsylvania utilities are substantially larger in size and, therefore, inherently attract a greater number of suppliers to their auctions. The Company's recent auctions for 24-month FPFR supply also resulted in a bare minimum number of suppliers – 3 in the first

[17] PJM Presentation on Capacity Auction Results 2025/26 (*20240821-item-08---2025-2026-base-residual-auction---presentation.ashx (pjm.com)*) – Growth in RTO capacity prices for 2025/26 to $269.92/MW-day versus $29/MW-day for 2024/25.

solicitation of DSP IV and 1 in the second. Although I have explained that this can be attributed to a number of different factors, the Company cannot ignore the risk of bidding for a product that may result in low supplier participation. Furthermore, in reviewing the suppliers that have participated in FPFR and block product solicitations in the past 6 solicitations 3 suppliers participated in block product solicitations only. Thus, while I cannot affirmatively conclude that suppliers who bid for block products only historically will simply choose not to participate if block is not available in DSP V, it could result in at least some choosing to do so and, consequently, decrease supplier competition.

Q. Do you agree with Mr. Ogur's analysis of the tranche sizes under his proposal? (OCA St. No. 1, p. 20.)

A. No, not entirely. Mr. Ogur's approach chooses to focus on forecast MWh rather than peak load contribution ("PLC") when considering tranche size. His argument is that while the percentage supply for each contract is only 25% - compared to 50% in the Company's proposal – the contract term is twice as long and is therefore equivalent. This is the wrong way to consider tranche sizing. No Pennsylvania utility, larger or small, evaluates or establishes tranche size based upon the perceived MWh a given supply may provide. Instead, tranche size is based upon the PLC as a responsibility load share at any given point in time. It is with this lens that UGI Electric established its tranche size. Table 1 below provides the estimated tranche sizes per product type for both the Company's product mix and that of the OCA's proposal. As shown in this Table, the 12-month FPFR has nearly twice the PLC of the 24-month FPFR product, which commensurately matches with the 140 MW estimated aggregate PLC less that of the 20MW ATC Block. Actual MWh are

likely to change from year to year based upon customer usage variances; however, PLC for UGI Electric has remained constant for the entirety of the default service plan dating back to 2011. It is with this view that tranche size should be viewed and commensurately based upon, which falls in line with the Company's approach.

Table 1. Estimated PLC and Tranche Size (MW) Per Product Type

Product	**UGI Electric**	**OCA**
ESTIMATED AGGREGATE Peak Load Contribution (GSR-1)	140MW	
ATC Block (MW per Tranche / MW Total Size)	10 / 20	NA
12-month FPFR (MW per Tranche / Total MW Size)	60 / 120	NA
24-month FPFR (MW per Tranche / Total MW Size)	NA	35 / 140

Q. Please describe Mr. Ogur's proposal with respect to the GSR-1 load cap. (OCA St. No. 1, p. 21.)

A. With the OCA's proposed 100% 24-month FPFR load following proposal, Mr. Ogur recommends that UGI Electric implement a 75% load cap instead of the Company's proposed 50% load cap. That is, a single supplier can provide up to 75% of the Company's FPFR portfolio under OCA's proposal versus 50% under the Company's proposal. His reasoning is that a supplier that bids and wins in two successive solicitations would be prohibited from participating in the two subsequent solicitations with a 50% load cap. By expanding the cap to 75%, the risk of low supplier participation is mitigated.

Q. Do you agree with his proposal regarding the load cap?

A. No, I do not. As discussed previously, the Company does not agree with the OCA's proposal to move to a 100% 24-month FPFR product mix and similarly does not find Mr.

Ogur's proposed load cap compelling. UGI Electric's 50% load cap was purposely set to align with the products proposed based upon the tranche size for the 12-month FPFR contracts Mathematically, the OCA proposed 75% load cap does not align with the Company's proposed two 50% tranches of 12-month FPFR supply. A 75% load cap would require bifurcation of the 50% tranche(s), undermining the Company's intent to maintain a larger tranche MW size.

It is also worth mentioning that the Company's proposed product mix includes 20 MW ATC Block, which is estimated to be approximately 24% of total GSR-1 supply. DSP V only proposes implementing a 50% load cap on the FPFR supply, not the ATC Block. Should a wholesale supplier bid and win both ATC Block products, the supplier's supply obligation would roughly equate to 74%. While these figures are estimates only and assume a supplier bids and wins across two different product types over a two-year period, UGI Electric's proposal roughly aligns with the OCA proposal in concept.

III. GSR-1 Joint Procurement Issues

Q. What does Mr. Ogur propose with respect to the rate allocation factors?

A. Mr. Ogur recommends that the Commission eliminate the price premium proposed by UGI Electric.[18] Further, in the event that the Commissions were to approve separate Energy Cost rates and resulting PTCs, Mr. Ogur also recommends the Company conduct separate procurements for residential and non-residential customer classes.

[18] OCA Statement No. 1, p. 34 lines 7-9.

Q. Do you agree with Mr. Ogur's proposal to conduct separate procurements for residential and non-residential GSR-1 customers if the rate allocation factors are not eliminated?

A. No, I believe doing so would be detrimental to both residential and non-residential customers in the GSR-1 rate group. Beyond those points made in Mr. Tyahla's Rebuttal Testimony, a primary consideration must be the ability to conduct successful solicitations to secure default service supply for customers at the least costs over time. Separating the residential and non-residential GSR-1 supply into separate auctions is likely to harm both customer groups by reducing tranche size and limiting the types of products to be procured. This is likely to result in an increased cost of the products if successful, or a failed bid and a default to the highly volatile spot market supply.

Q. Please describe the load characteristics of the residential and non-residential GSR-1 customers.

A. Based upon a review of current customer orientation the Company has calculated that of the estimated 140MW of GSR-1 supply, 31MW are attributed to non-residential customers and the remaining 110MW are attributed to residential customers. Furthermore, an additional 5-7% of GSR-1 customers shop for their electricity at any given moment, reducing the residential default service PLC to approximately 102-105 MW and non-residential default service PLC to approximately 29 MW.

Q. How would separate procurements impact each subset of GSR-1 customers?

A. Considering the non-residential GSR-1 customer group first, a PLC of 29-31 MW (shopping vs. total) effectively only provides less than half of the MW-measure needed to supply a single tranche of the Company's proposed 12-month FPFR supply, with no opportunity to inlay a reasonably sized ATC block product. If split in half to create two tranches of approximately 15 MW, the FPFR supply is unreasonably small and not likely to be successful if bid.

The residential customer segment fairs slightly better with a PLC of approximately 105 MW, or 110 MW if including shopping customers. If a 20 MW ATC Block product is layered in, the supply amount for FPFR reduces to about 85 MW or only about 1.4 times the currently proposed tranche size in UGI Electric's proposal. If divided to create at least two tranches and limit single supplier risk, tranches are only approximately 42 MW. While the bid for this product is likely to still entice suppliers to bid, it may result in a higher risk premium and therefore higher costs to customers. If the ATC Block were removed, tranche size would be just under the tranche size proposed by the Company, but also requires complete reliance on a single product with a 50% turn-over unless tranche size is substantially reduced at the risk of supplier disinterest and/or higher bids.

Q. Does a combined procurement approach benefit both subsets of GSR-1 customers?

A. Yes, it does. UGI Electric's supply is already small which led the Company to combining these customers together to grow the MW-measure. Reverting to a split solicitation is only set to harm both customer segments.

IV. Penn Renewables' Issues

Q. In testimony, Penn Renewables generally objects to large customer-generators being classified as GSR-2 customers. Why is it reasonable to classify them as GSR-2 customers?

A. Large customer-generators are appropriately classified as GSR-2 customers due to their general sophistication, likely impact on default service solicitations, and overall grid impact from a default service prospective. Starting with impact to the grid in relation to default service, large customer-generators are those that have a system peak load impact ("SPLI") of at or above 100 kW. These customer-generators primarily export power to the grid over the course of a month and during peak exporting hours, depending upon the system type, could export near the nameplate capacity and, therefore, similarly impact the grid resources as customers that import or consume. Notably, the Company's current GSR-2 is applicable to those consuming-only customers with SPLI at or above 100 kW as well.

As explained in my Direct Testimony, large customer-generators will likely export a substantial amount of energy and are likely to impact the overall default service supply (MW and MWh), which is also likely to impact the competitiveness of bids from wholesale suppliers. In summary, large customer-generator exports result in less aggregate supply available for wholesale suppliers to bid on and add additional volatility and variability to the supply mix – otherwise defined as risk. I expanded upon this notion in my direct testimony, highlighting two prominent risks the UGI Electric DSP V Plan attempts to mitigate – impact of retail choice participation and the impact of net metering customer-generation. Based upon the 30 new large customer-generator applications received, including those 12 systems highlighted in Mr. Crist's testimony, amounting to 22 MWs

The Company estimated the total generation would represent approximately 6% of UGI Electric's GSR-1 load. This estimated supply amount is substantive and is likely to result in higher bid prices and/or lower supplier participation for a GSR-1 program that is already challenged with both issues and meant to be resolved in DSP V through UGI Electric's proposed plan. In short, the inclusion of large customer-generators in the GSR-1 rate group negatively impacts small customers – residential, commercial, and industrial. While the Company does not currently serve any large customer-generators through default service today, by establishing appropriate criteria whereby large customer-generators are provided service under the GSR-2 rate group, energy requirements will be settled through the spot market instead of through fixed price product offerings from wholesale suppliers, which reduces GSR-1 supplier risk, reduces customer risks, and improves the solicitations and associated pricing. This will also appropriately safeguard against potential subsidy impacts for GSR-1 customers related to large customer-generators.

Finally, similar to traditional large business customers, large customer-generators are more sophisticated in their understanding of and access to the wholesale and retail markets. These customers actively understand how energy markets work, can evaluate the risk and challenges of market entry at different points in time, and actively enter and exit the markets based upon how it impacts their business ventures and associated operations[19].

[19] Per the details provided on Penn Renewables' website, their operations are sophisticated, robust, and large in scale. As of August 28, 2024, Penn Renewables reports 787 MW of installed solar projects across more than 150 projects – with a straight line average of over 5 MW per project. (https://pennrenew.com/) In his direct testimony, Mr. Crist asserts that Penn Renewables has over 300 projects across the Commonwealth with arrays between 1-2 MWs. (see Penn Renewables Statement No. 1, p. 3 lines 21-22 and p. 4 lines 7-8). While data provided in testimony and on its website is somewhat conflicting, the overall nature of their project size is large, with between 12-24 MWs of active project nameplate capacity under development in the UGI Electric service territory (Penn Renewables Statement No. 1, p. 4 lines 10-12).

It is with this level of understanding and market access confidence that large customer-generators are best aggregated into the GSR-2 rate group.

Q. Are there any other factors considered by UGI Electric when proposing to align large customer-generators with other large customers on GSR-2?

A. Yes, there were two. First, as there are currently no large customer-generators interconnected with UGI Electric's system that would be impacted by this adjustment when implemented, there is no concern with grandfathering rules or other special adjustments to rate classifications that bifurcate customers based upon implementation date – implementation for all large customer-generators will be the same. Second, the Company qualitatively considered the types of business customers impacted by the rule. Any business customer that has a demand of 100 kW or greater is already classified as a GSR-2 customer, receiving spot market pricing. Therefore, if this customer then interconnects a net metering qualified system with a nameplate at or above 100 kW, the customer is already experienced with navigating spot market pricing and/or shopping through the retail market.

Q. Mr. Crist states that it is unreasonable to classify customers based on their peak supply. (Penn Renewables St. No. 1, p. 20.) Do you agree?

A. No, I do not. The classification of large customer-generators based upon their SPLI, which can also be effectively defined as nameplate capacity, is used in the Pennsylvania AEPS Act when establishing customer-generator eligibility as a net metering resource. The Act specifically defines customer-generator as a "nonutility owner or operator 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, except for customers whose systems are above three megawatts and up to five megawatts who make their systems available to operate in parallel with the electric utility during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the primary or secondary purpose of maintaining critical infrastructure, such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities, provided that technical rules for operating generators interconnected with facilities of an electric distribution company, electric cooperative or municipal electric system have been promulgated by the Institute of Electrical and Electronic Engineers and the Pennsylvania Public Utility Commission."[20] Clearly, the nameplate capacity of the customer's system determines whether they are eligible to participate in net metering as a customer-generator.

Also, the effective use of SPLI in the UGI Electric SPLI proposal adds reasonable and appropriate classification criteria for large commercial and industrial net metering customers, defining which GSR rate they are assigned to in accordance with recognized default service supply impacts and risks.

Mr. Crist also incorrectly states that "UGI has created a 'procurement class' based upon the customer's peak system impact, not their load."[21] UGI Electric has not created a new procurement class; the Company has developed criteria to objectively recognize and classify commercial and industrial customer-generators between the GSR-1 and GSR-2 rate groups based on similar supply impacts.

[20] 73. P.S. § 1648.2.

[21] Penn Renewables St. No. 1, p. 20, lines 9-10.

Q. Penn Renewables indicates that it is developing twelve 1 -2 MW facilities in UGI Electric's service territory. (Penn Renewables St. No. 1, p. 4.) How large are 1 – 2 MW solar generating facilities?

A. Annual export of a solar generating facility is based upon a number of different factors, such as nameplate capacity, facility location and orientation, and weather and/or cloud cover. Based upon the National Renewable Energy Laboratory ("NREL") Commercial Photovoltaic ("PV") baseline statistics, the Pennsylvania DC Capacity Factor is estimated to be between 14-14.6%.[22] Assuming a liberal 14.6% capacity factor, each 1 MW nameplate solar facility could be expected to produce about 1,279 MWh annually. In fact, Penn Renewables has provided data to the Company related to a 1 MW project that confirms this figure and actually demonstrates it as conservative.[23]

Q. Are large customer-generators similar to small business customers?

A. No, they are not. As explained above, a 1 MW nameplate solar facility is forecast to export 1,279 MWh per year. Comparatively, a small business customer (i.e., demand below the 100 kW demarcation) is likely to consume on average approximately 19 MWh per year.[24] Thus a 1 MW nameplate solar facility is a 67 times the size of UGI Electric's average small business customer on a MWh basis. Comparatively, UGI Electric's largest customers average a consumption of 1,358 MWh per year, very comparable to the 1,279 MWh export capability of a 1 MW solar facility; and clearly with this data it can be exemplified that a 2 MW solar system would create output far above the average consumption of UGI

[22] See NREL statistics: https://atb.nrel.gov/electricity/2023/commercial_pv

[23] Penn Renewable CONFIDENTIAL response PR-I-5, including attachments PR-I-5.1 and PR-I-5.2.

[24] Based upon UGI Electric average for GSR-1 customers served under Rates GS-1 and GS-4 per UGI Electric's 2021 rate case proof of revenue.

Electric's largest customers. Even under a situation where a small business customer with a demand of 99 kW were to consume that peak demand for every hour throughout an entire year – a feat that is both unrealistic and to which UGI Electric have never seen – the customer would only consume 867 MWh per year – or less than 68% the generation of a 1 MW nameplate solar facility. A simple comparison between customer size and import or export of power clearly shows that a large customer-generator is not similar to a small business customer.

The basic principles supporting distribution grid design is to construct the grid to, under traditional customer load flows, provide power to end-use customers based upon their demand. This was achieved by evaluating customer peak load contributions or PLCs to understand their maximum demand, add an additional buffer in the event historic peak demand was exceeded, and then design and build the grid to accommodate that need. With the advent of customer-owned and operated generating resources that evaluation considered not just consumption but also generational capability. Current Pennsylvania net metering rules allow residential customers to interconnect a system up to a 50 kW sized generating facility and all other customers to interconnect a system up to a 3 MW sized generating facility.[25] Under the UGI Electric DSP V plan the Company proposes to maintain the already implemented 100 kW demand split for consuming customers based upon their peak impact as this value is unchanged under the application of the proposed SPLI criteria. As such, any customer over 100 kW is assigned to the GSR-2 rate group; those at or below 100 kW are assigned to GSR-1. As explained in my Direct Testimony,

[25] Residential, commercial, and industrial customers must also adhere to other net metering rules such as approved technology types, metering requirements, and so on. Further, commercial and industrial net metering customers may also build a generating resource up to 5 MW with the agreement that they operate in accordance with PJM rules and requirements during grid emergencies.

this demand split was gradually implemented following the Commission's Retail Markets Investigation, driven by the goal to orient similar customers together. Larger customers were deemed by the Commission as more sophisticated and capable of shopping in the market. Further, these customers who were more likely to be active in the competitive market also likely had a negative impact on the ability of utilities to solicit for and obtain reasonably priced default service.

It is based upon this demand split and its objectives that provides the clear difference between large customer-generators and those of small business customers – their sophistication, ability to understand and access the market, and the impact they have on default service. As I provided in my Direct Testimony and highlighted above, there are real and substantial impacts to portfolio risk if large customer-generators are interconnected and serviced under the GSR-1 rate group, as it would likely undermine the default service solicitation. The result would likely be higher supplier bids due to greater risk to the suppliers from variable supply obligations due to these larger customer-generators and/or lower or no supplier bids for some or all products. Large customer-generators are more akin to their large energy consuming counterparts and are therefore appropriately aggregated on the GSR-2 supply rate. This conclusion is further supported by Penn Renewables' response to "UGI to PR-I-4," which shows that Penn Renewables understands the challenges of the market and business design mechanics and that Penn Renewables wants to remain on the GSR-1 rate group as the more financially beneficial solution to support project profitability. While Mr. Crist errantly opines in this response that the GSR-2 rate is not a "retail value" – a conclusion I have previously addressed – one could conclude that if other financially beneficial rate offerings, either through UGI Electric

programs or other means, were to arise, Penn Renewables would pursue them, leaving default service. It is this market knowledge, sophistication, and impact to default service that leads the Company to conclude that the GSR-2 rate is most appropriate for large customer-generators.

Q. On page 18 of his direct testimony, Mr. Crist states that if the locational marginal price ("LMP") is negative in a certain hour, customer-generators will be debited for generation that they produce in that hour. Why is that a reasonable approach?

A. If the LMP for the PPL Residual Aggregation point is negative in any given hour, it effectively means that supply for power exceeds demand. This is the market's signal to generators to reduce supply. It is with this understanding that "debiting" customer generators during any negative pricing hours is appropriate – the market is attempting to communicate to these large customer-generators to reduce supply. Importantly, assigning large customer-generators to GSR-2 on the basis of SPLI ensures that market price signals such as these are transparent to large customer-generators, who can then work to reduce supply and maintain grid stability and reliability. Comparatively, if large customer-generators are provided service under GSR-1, there would be no such price signals to the customer-generator and no reason to work to reduce supply in order to support the maintenance of grid stability and reliability.

Q. Mr. Crist suggests that when customer-generators produce more power, the PJM nodal price will decrease, and customer-generators will be paid less. (Penn Renewables St. No. 1, pp. 20-21.) Please respond to this argument.

A. As discussed above, such price signals up to and including negative pricing are an appropriate price signal for the customer-generator market to experience such that periods of oversupply are not continually or further oversupplied and periods of undersupply are appropriately incented for supply. Indeed, during periods of tight supply, customer-generators will see higher pricing for their production.

Q. Mr. Crist states that the GSR-2 pricing structure for GSR-2 customer generators is not "based on UGI's cost to provide retail service…." Penn Renewables St. No. 1, p. 21, lines 14-16. Is this correct?

A. No, Mr. Crist's statement is not correct. As provided by the Company in response to Penn-I-2, all components of GSR-2 retail service are provided to large customer-generators including generation, capacity, transmission, ancillary services, administrative charges, taxes and line losses were appropriate. The GSR-2 rates are the same for all customers on GSR-2, including market-based spot locational margin prices ("LMP"), capacity results, and ancillary services; transmission owner-established transmission rates; or UGI Electric defined administrative and related charges. The resulting GSR-2 customer bill, credit or end-of-year compensation (i.e., for net metering customers) are customer-specific, based upon customer usage or export (kWh) and PLC and NSPL (kW) values relative to the appropriate GSR-2 rate components. UGI Electric is in no way proposing a change to the

regulation-defined full retail rate compensation, from month-to-month in a year, or price-to-compare cash-out compensation, at the end of the year.

Q. Does UGI Electric's proposal treat GSR-2 customer generators as if they were "wholesale generators."

A. No. Net generating GSR-2 customers are aggregated with other customers on the GSR-2 rate schedule when creating the schedule and settlement values submitted to PJM. These customers are not uniquely identified or otherwise broken out and are not required to meet PJM wholesale generator rules and requirements. There are a broad suite of rules and requirements to be approve as a PJM wholesale generator, such as having a PJM feasibility and/or system impact study completed, working through the PJM interconnection queue, and providing various forms and associated collateral for market participation. Further, when the system is approved and operational, generators much provide bid submissions based upon performance criteria. However, those generators must operate according to their commitments, meet grid communication and operation rules, and provide a series of other rules and requirements based upon their resource type. Net metering customer-generators on UGI Electric's GSR-2 rate schedule are not responsible for any these requirements and, as such, are not treated as wholesale generators.

Q. Mr. Crist argues that the Company should not apply loss factors to customer-generator produced energy. (Penn Renewables St. No. 1, p. 22, lines 4-5.) Do you agree?

A. No, I do not. UGI Electric default service supply is calculated by aggregating customer metered load (retail load) and adding losses to support settlement through the PJM wholesale market. As such, default service customers pay for line losses as a component of their total supply package. Net metering customers who net generate are actually compensated for, not charged, line losses as their totals are grossed up for losses. UGI Electric is not proposing any changes to the PTC calculation methodology or the related net metering compensation methodology – the latter of which is beyond the focus and purview of this proceeding.

Q. Mr. Crist then states that the law requires that customer-generators be compensated for all energy – not energy reduced by loss factors and other adjustments. (Penn Renewables St. No. 1, p. 22.) Do you agree with his statement?

A. No. I believe Mr. Crist misunderstands how line losses are applied when calculating net metering customer compensation. As discussed in the prior question, for net metering customers, line losses are included as part of compensation and are not a deduction from compensation. Said another way, the retail meter export value is grossed up for losses before compensation is tabulated and provided. As such, net exporting customers benefit

from the line loss inclusion in the rate calculation – it is not a detraction as Mr. Crist's testimony implies.

Q. On page 23 of his direct testimony, Mr. Crist states that under the GSR-2 pricing methodology, customer-generators will provide benefits to other customers, such as supporting reliability and lower costs, but will not receive compensation for those benefits. Do you agree with his argument?

A. I disagree with Mr. Crist's argument that such considerations should be part of net metering compensation and as a component of default service. Different net metering facilities may have local system benefits or impacts – providing for improved or less reliability, lower system costs or more, and so on. However, default service rules and associated net metering rules do not consider these components when considering eligibility or compensation. Moreover, in response to discovery, Mr. Crist was unable to provide any analysis or quantification of such benefits, other than alleging they would occur under generalized economic theory, with no recognition of other related costs to consumers, such as subsidies paid to customer-generators which incentivize construction or the opportunity for lower cost wholesale supplier power when solicited through competitive procurements.

Q. Mr. Crist also argues that customer-generators should receive compensation for production during PJM's PLC or Network Service Peak Load ("NSPL") hours. (Penn Renewables St. No. 1, p. 24.) Is he correct?

A. No. The purpose of both PLC and NSPL customer tags are to charge customers for their respective contribution to PJM capacity peak loads and utility transmission peak loads,

respectively. This process is not intended to compensate net metering customer-generators that provide excess generation during a PLC or NSPL peak hour, should it occur. The PLC and NSPL tag creation process assigns a zero for any peak hour where a net metering customer-generators generated instead of consumed power. As a result, the responsibility share of net metering customer-generators decreases for each of the five coincidental peak ("5CP") hours that customer is either net generating or consuming no power from the grid. At a maximum, customer-generators could have a PLC and/or NSPL of zero and as a result, not be charged for capacity and/or transmission. This process for GSR-2 customers is not a change in rules or compensation, but the correct application of costs and compensation for this rate group.

Q. Mr. Crist argues that if the customer-generator has any demand related charges in a given hour, that the rate paid to customer generators will be less than the rate charged to other GSR-2 customers. (Penn Renewables St. No. 1, p. 25, lines 3-6.) Please respond.

A. In response to Penn Renewable's Set I interrogatories, PENN-I-2, UGI Electric provided the calculation methodology for GSR-2 net metering customers. As the Company explained, full retail rate compensation is directly commensurate with the components of the rate, specific to the customer. In the methodology, capacity and transmission costs are based upon the customer's PLC and NSPL values. If a net metering customer-generator generates excess supply during the peak hours selected to define the PLC and NSPL values for a given year, the customer's resulting PLC and NSPL customer tags will be lower than if the customer were not generating, assuming the customer has consumption during those

hours and contributes to the peak demands. As such, a GSR-2 net metering customer would be compensated at the full retail rate, with capacity and transmission compensation directly related to the peak system impacts of that customer. The compensation is based upon the components of the GSR-2 PTC and the customer's own operation. UGI Electric is not proposing to make changes to the compensation methodology defined in the AEPS Act and the Commission's regulations. Therefore, Mr. Crist's inference that there is something incorrect about UGI Electric's application of the regulatorily mandated compensation requirements is unfounded. A lower PLC and NSPL tag is directly based upon the customer's own operations. Based on data provided in discovery by Penn Renewables, PLC and NSPL values for their anticipated installations are estimated to be very low.

Q. Mr. Crist also states that the rate charged to non-generating customers will decrease as consumption increases and that this violates the regulations. (Penn Renewables St. No. 1, pp. 25-26.) Is this correct?

A. No, Mr. Crist's assertion is not correct. UGI Electric's rates do not decline – the customers' PLC, NSPL, and MWh exports may change based upon customer actions. The PLC rate is based upon the PJM capacity price, defined through a PJM managed annual capacity auction. LMPs are also established by PJM on an hourly basis based upon market clearing prices – a process not managed by UGI Electric. The transmission rate is based upon utility transmission costs and again set for a year through a Federal Energy Regulatory Commission ("FERC") filing by the Transmission Owner. All rates are established either by the market or by Transmission Owners, not UGI Electric. Also, as certain rate elements are kW based and fixed monthly charges and not kWh consumption based variable charges,

if an average per kWh rate is calculated across all charges, then as consumption increases the average per kWh value would decrease. This same mathematical outcome applies to any GSR-2 non-generating customer as well. Therefore Mr. Crist's assertion is incorrect.

Q. Mr. Crist suggests that the Company's procurement plan for GSR-2 customers violates Act 129 because Act 129 requires a competitive procurement process that includes auctions, requests for proposals or bilateral agreements, but "[t]here is no provision in the purchase plan for GSR-2 customers that includes auctions, RFPs or bilateral contracts." (Penn Renewables St. No. 1, p. 22, lines 13-17.) Is he correct?

A. Mr. Crist appears to err in applying the regulations through which UGI Electric and other Pennsylvania utilities have built default service plans. First, I note that this is a legal issue which the Company will address in more detail in its Briefs in this proceeding. However, this argument is clearly incorrect. The spot market purchases for GSR-2 would be accomplished through bilateral agreement. Section 2807(e)(3.1) of the Public Utility Code requires use of auctions, request for proposals and/or bilateral agreements[26]; however, Mr. Crist overlooks that Section 2807(e)(3.2) further provides that "*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, [and] (iii) Long-term purchase contracts, entered into as a result of auction, request for proposal or bilateral contract… not greater then 20 years.*"[27] Pursuant to this authority, all electric utilities in the Commonwealth offer spot

[26] 66 Pa. C.S. § 2807(e)(3.1).
[27] 66 Pa. C.S. § 2807(e)(3.2)(i)-(iii)

market default service to larger customers. Notably, UGI Electric procures spot market supplies for the GSR-2 customer group directly through PJM.

The implementation of spot market purchases, short-term and long-term purchases have also been applied on a total default service plan basis. This means that a prudent mix of products must be implemented across the entire plan, not on a per customer or per class basis. Again, UGI Electric's procurement plan fully complies with the Commonwealths default service regulations.

Q. Does this conclude your rebuttal testimony at this time?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. –	:	
Electric Division For Approval of	:	Docket Nos. P-2024-3049343
a Default Service Plan (DSP V) for	:	G-2024-3049351
the Period of June 1, 2025 through	:	
May 31, 2029	:	

REJOINDER TESTIMONY
OF
STAN C. FARYNIARZ

UGI ELECTRIC STATEMENT NO. 2-RJ

Dated: October 1, 2024

I. Introduction

Q. Please state your name and address.

A. My name is Stan C. Faryniarz. My business address is 370 Main Street, Suite 325, Worcester, MA 01608.

Q. By whom are you employed, and in what capacity?

A. I am employed by Daymark Energy Advisors as a Principal Consultant and Practice Area Lead. I am testifying on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") in this proceeding.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I have adopted the direct and rebuttal testimony previously submitted by Mr. Rouland. My direct testimony, UGI Electric St. No. 2, was submitted on May 31, 2024, as Appendix C to the Petition. My rebuttal testimony was submitted on August 30, 2024 as UGI Electric St. No. 2R.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rejoinder testimony is to respond to Penn Renewables, LLC ("Penn Renewables") witness James L. Crist, P.E.'s, surrebuttal testimony submitted on September 25, 2024. Note carefully that any topics or assertions made by Mr. Crist not addressed in this rejoinder or any of my testimony should not be construed as agreement with his testimony.

I also note that while I am not responding to the Office of Consumer Advocate's witness Mr. Ogur's surrebuttal testimony, I continue to disagree with his assertions for the reasons provided in my direct and rebuttal testimony.

Q. Are you sponsoring any Exhibits with your rebuttal testimony?

A. Yes, I am sponsoring 5 Exhibits:

- Exhibit SCF-1-RJ – Historical Analysis of PPL Zonal LMPs Since 2020
- Exhibit SCF-2-RJ – UGI response to PENN – IV No. 10
- Exhibit SCF-3-RJ – UGI response to PENN – III No. 8
- Exhibit SCF-4-RJ – UGI response to PENN – IV No. 7
- Exhibit SCF-5-RJ – UGI response to PENN - III No. 30

II. <u>UGI Electric's Motivation for Assigning Large Customer Generators to GSR-2</u>

Q. Penn Renewables avers that UGI Electric's motivation for assigning large customer generators with supply peak load impacts (SPLI) of 100 kW or more is to thwart renewable project development. Is this correct?

A. Of course not. The surrebuttal testimony of Mr. Crist makes several such unfounded assertions.[1] There is no UGI Electric testimony by any witness that suggests ill-intent towards renewable projects or their developers. Notably, my firm, Daymark Energy Advisors, has served a large number of renewable project merchant and utility developers

[1] See for example Penn Renewables Statement No. 1-SR, p. 6, line 20; p. 7, lines 5-7; p. 8, lines 6-9.

across North America since its founding in 1980, and such clients are the focus of more than one of our practice areas.

To the contrary, as my direct and rebuttal testimony make very clear, classifying larger default service customers with an SPLI of 100 kW or greater, whether they only consume or also generate power for export, was done to acknowledge the similarity of default service supply risks among UGI Electric's customers with largest impacts, those above 100 kW, and protect those residential and small commercial customers served under GSR-1 from paying default service rates that are greater than necessary. Such classification of SPLI also prevents insufficiently competitive pricing from default service suppliers resulting from unnecessary risk. Put another way, UGI Electric's intent is to ensure that its default service plans (DSP), including DSP V, "acquire electric generation supplies at the least cost to customers over time in accordance with 66 Pa. C.S. § 2807(e)(3.3)(ii) and 52 Pa. Code § 54.185(d)."

III. UGI Electric GSR-2 Load and Rates

Q. Mr. Crist cites some statistics in his testimony regarding the load served under UGI Electric GSR-1 and GSR-2 default service pools. Can you clarify the amount of load falling into these two default service classifications?

A. Yes. Mr. Crist's surrebuttal testimony on p. 4, lines 20-21, not only appears to conflate numbers of customers and load served, but is also incorrect about the amount of UGI Electric GSR-2 load.

To set the record straight, for the 12 months ending May 31, 2024, UGI Electric GSR-1 load served was 634,043 MWh, approximately 86.5% of its total default service load. For

that same period, GSR-2 customer load served was 98,842 MWh, or approximately 13.5% of its total default service requirements. Mr. Crist's use of customer count percentages to rationalize GSR applicability is not relevant to the real default service risk issues addressed by UGI Electric's proposal.

Q. Mr. Crist appears to suggest on pp. 5-11 and again on p. 17 of his surrebuttal that large customer generators are not being paid the "full retail value" under the GSR-2 rate structure, in part because it is an hourly-priced service under which the energy component is procured from the wholesale PJM spot market. Is he correct?

A. No, and this topic will be addressed in greater detail by Ms. Tracy Hazenstab for UGI Electric in her rejoinder testimony.

In any case, UGI Electric's GSR-2 rate is a fully loaded retail rate under its tariffs. It contains all products necessary for serving retail customer power supply requirements, including energy, capacity, transmission, ancillary services and Alternative Energy Portfolio ("AEPS") requirements, and all other retail rate components.

Q. Do other EDCs in Pennsylvania and outside of the Commonwealth also service larger commercial and industrial customers using an hourly-priced retail default service rate?

A. Yes, it is a standard means of providing default service to such customers both within and outside of Pennsylvania, for precisely the reasons contained in my direct and rebuttal testimony. The variable loads associated with larger commercial and industrial customers, the attrition risks they present either leaving to shop for their power supply requirements

or coming into default service, and their greater sophistication and wholesale and retail market knowledge as large energy consumers are the reasons for this construct. The Order coming out of the Pennsylvania Public Utility Commission's ("PA PUC") retail market investigation highlights these factors as well. This was explained and that Order was cited in UGI Electric's response to Penn Renewables interrogatories Set IV, Response 10, which I append as Exhibit SCF-2-RJ – PENN IV-10. There is nothing new, discriminatory or non-compliant in UGI Electric's large customer GSR-2 default service rate.

Q. Mr. Crist suggests that UGI Electric "admits that the GSR-2 PTC is settled in the wholesale market."[2] Is this statement correct?

A. No. While the GSR-2 price to compare is comprised of energy procured from the PJM wholesale spot market, it also includes all other necessary retail product components including capacity, transmission, ancillary services and AEPS requirements, and others. Only the energy component of the PTC is settled in the wholesale market. GSR-1 also has component energy cost elements that are settled in the wholesale market in the form of

[2] Penn Renewables Statement No. 1-SR, p. 5, lines 18-19.

forward contract resources which must be bid in and which include energy block purchases and FPFR contracts, and imbalance spot market settlement under the PJM system.

Q. Mr. Crist alleges that "the GSR-2 default service rate under UGI's proposal is likely to be negative under commonly occurring circumstances."[3] Is this correct?

A. Again, no. Under my supervision, I requested from my team an analysis of how often nearby PPL zone hourly locational marginal prices ("LMP") have been negative over the past four and a half plus years, over the course of calendar years 2020 through 2023, plus through September 25, 2024. The table below presents these results.

Table 1 - PPL Zonal Real-Time Locational Marginal Prices Since 2020 (UGI Statement 2-RJ)

Period	No. of Hours Negative LMP	No. of Daylight Hours Negative LMP	Total Hours Over Study Period	Fraction of Negative LMP Hours	Fraction of Daylight LMP Hours
2020-2024	63	30	39,432	0.16%	0.08%
2020	11	3	8,784	0.13%	0.03%
2021	6	3	8,760	0.07%	0.03%
2022	7	5	8,760	0.08%	0.06%
2023	24	15	8,760	0.27%	0.17%
2024	15	4	6,456	0.23%	0.06%

As indicated in this table, the fraction of negative LMP hours over the entire study period was 0.16%, which equates to 16 hours of negative LMPs for every 1000 hours. If reduced to the fraction of negative LMP hours during daytime solar irradiance over the entire study period, the result was 0.08%, or 8 hours out of every 1000 hours. Even during the year that saw the maximum amount of negative LMPs during daylight hours, 2023, it was 0.17%,

[3] Penn Renewables Statement No. 1-SR, p. 5, lines 11-12.

or 17 hours out of every 1000 hours. This is hardly "commonly occurring." My workpapers are provided as Exhibit SCF-1-RJ.

Q. Mr. Crist maintains on p. 20 of his surrebuttal testimony that the UGI Electric's GSR-2 rate <u>decreases</u> as output increases.[4] Is he correct?

A. Yet again, he is incorrect. Please refer to Exhibit SCF-3-RJ – PENN III-8, which is a table Penn Renewables requested from UGI Electric as a follow up to PENN I-2. This, table with a detailed workup of an hourly settlement example, contains the GSR-2 PTC rate calculation under different scenarios for large customers consuming power and large customer-generators exporting power at varying levels (specifically columns 4, and 6-7 from the left). Notice how in row 1 for each of these columns, three cases of generation are profiled, one for 100 kWh of net export (column 6), another for 200 kWh of net export (column 7), and for 1000 kWh of net export (column 4). Now, please review the GSR-2 PTC rate calculated in each of those scenarios in row 23 of the table. The PTC rate for 100 kWh of exported generation is calculated to be $0.0353/kWh. When output doubles to 200 kWh under the same conditions including hourly LMP, the corresponding PTC rate for

[4] Penn Renewables Statement No. 1-SR, p. 20, lines 1-13.

exported generation increases to $0.0386/kWh. When output increases to 1000 kWh under the same conditions, the PTC rate for exported generation increases to $0.0412/kWh. This exhibit entirely contradicts Mr. Crist's assertion, and I would contend that it is his exhibit that purportedly supports his assertions that represents the "misdirection (that) should be ignored."[5]

IV. Definition of Large Solar Projects

Q. Mr. Crist describes Penn Renewables solar projects as "(s)mall generators."[6] Is this statement accurate?

A. Not according to the Pennsylvania AEPS, PA PUC criteria, nor the federal Energy Information Administration ("EIA"). Again, I refer the Commission to Exhibit SCF-2-RJ – PR IV-10 appended to this testimony. As responded to Penn Renewables there, multiple federal agencies, most notably the EIA, define "large" or "utility" scale solar as projects with a nameplate capacity of 1 MW or more. The Solar Energy Industries Association does as well. The PA PUC actually requires that any alternative energy system proposed by "customer generators" of 500 kW nameplate capacity or larger undergo explicit review and approval; a clear demonstration and acknowledgement by the Commission that there is a

[5] Penn Renewables Statement No. 1-SR, p. 20, lines 10.
[6] Penn Renewables Statement No. 1-SR, p. 6, lines 9-10; p. 7, line 1.

difference between small and large customer generators which drives logical differences in regulatory considerations.

Moreover, as noted by Mr. Crist, Penn Renewables has over 300 solar arrays in development across the Commonwealth that are 1 to 2 MW in size. Penn Renewables St. No. 1, pp. 3-4. Penn Renewables is not a "small generator."

V. Impact of Large Solar Projects on GSR-1 Default Service Load

Q. What does Mr. Crist say about the size of typical Penn Renewables projects?

A. He contends that of the 12 such projects proposed in UGI Electric's service territory, most are "small, under 2000 kW each." (Penn Renewables St. No. 1-SR, p. 6.)

Q. Are the 12 Penn Renewables projects the only ones proposed in UGI Electric's footprint?

A. No. Please refer to my direct testimony, p. 27, lines 18-23. Based on applications received by UGI Electric in 12 months ending May 31, 2024, up to 22 MW of large customer generation could come on-line in the next 3 years.

Q. How much generation does that represent?

A. Again, referencing my direct testimony, "(e)xcess (emphasis added) power production from these customer-generators could range between 35,000,000 to 45,000,000 kWh annually." (UGI Electric St. No. 2, p. 27.)

This equates to approximately 6% of GSR-1 default service 1oad. (UGI Electric St. No. 2, p. 28.)

Q. In your direct and rebuttal testimony, have you described the risks that over-procurement could present to UGI Electric's GSR-1 portfolio and default service customers?

A. Yes, first in the context of large customer shopping, but the impacts are the same with large customer-generators.[7]

> A substantive decrease in load, or material change in the chance of such a decrease, could result in higher costs to default service customers due to an increase in supplier risk premia, a lack of suppliers willing to undertake such risk and participate in auctions, especially for FPFR products, or from the over-procurement of ATC contracts, which could result in additional costs to customers associated with the spot market sale of excess energy.

Further, as I describe in my surrebuttal testimony.[8]

> **"…**large customer-generators will likely export a substantial amount of energy and are likely to impact the overall default service supply (MW and MWh), which is also likely to impact the competitiveness of bids from wholesale suppliers. In summary, large customer-generator exports result in less aggregate supply available for wholesale suppliers to bid on and add additional volatility and variability to the supply mix – otherwise defined as risk."

Q. Effectively, what is the impact of potential GSR-1 load erosion from this much large customer generation on UGI Electric's DSP V portfolio?

A. It could materially eat into the generation procured under DSP V. For instance, one supply resource, the proposed 20 MW of around the clock (ATC) block is expected to provide

[7] UGI Electric Statement 2, p. 24, lines 11-19.
[8] UGI Electric Statement 2-R, p. 18, lines 14-19.

175,200 MWh of generation annually.[9] If all anticipated solar projects were exporting between 35,000 to 45,000 MWh annually, this would require real-time spot market liquidation of the ATC blocks to the tune of 20% - 26%. If liquidation of the block product is done at lower LMPs than the energy forward purchase price, that would result in GSR-1 customers paying significantly more for default service than planned.

These risks are compounded by the fact that if the planned DSP V blocks are liquidated, or if not, FPFR contract suppliers are left to supply more or less, respectively, of load following supply to GSR-1 customers.

In both of these scenarios, FPFR contract suppliers could either decide not to bid at all to supply such a small but risky load profile, potentially resulting in an auction failure, or embed significantly higher risk premia into their bids.

This potential for solar exports disrupting GSR-1 load settlement with PJM is another related risk. If a certain amount of exported solar from the up to 22 MW of potential solar in the UGI Electric service territory is expected and bid into UGI Electric's PJM settlement account day-ahead, but it doesn't show up the following day due to cloudy conditions or solar project output disruptions, and the load following suppliers will bear the risk of procuring additional supplies.

Finally adding 22 MW of supply to the GSR-1 procurements would significantly impact tranche size. UGI Electric carefully designed its GSR-1 procurement plan to both provide large enough tranches to encourage bidders while at the same time allowing for rate stability. Reducing tranche sizes will likely discourage bid participation and/or increase

[9] 20 MW X 8,760 hours annually = 175,200 MWh.

bid premiums. In addition, reducing the number of tranches will negatively impact rate stability and/or disrupt the procurement approach. See also the response to Penn Renewables Set IV, number 7 which is provided as Exhibit SCF-4-RJ and to Penn Renewables Set III, question 30, which is provided as Exhibit SCF-5-RJ.

Foisting this kind of risk from large customer-generators onto the shoulders of small residential and commercial customers with loads of less than 100 kW is unfair, bad policy, and is inconsistent with the rigorous and necessary role the PA PUC plays in reviewing and approving on behalf of customers the Pennsylvania EDC default service plans as it is doing so in this proceeding.

VI. Other Rejoinder Topics

Q. Mr. Crist generally avers that UGI Electric's GSR-2 classification approach and PTC rate for exported energy fails to comply with the Pennsylvania AEPS Act. Do you agree?

A. No, and I will note some examples where he has failed to make his case.

First, please see Section III herein of my rejoinder testimony, specifically pp. 4-5. As I demonstrate, he incorrectly states that the GSR-2 rate, which has been in existence for all UGI Electric default service plans, does not comply with the AEPS because it does not offer "full retail value." In fact, I have demonstrated herein that UGI Electric's GSR-2 PTC rate is a fully loaded retail rate and is similar to default service rates for all other Commonwealth EDCs applicable to large commercial and industrial customers. If it were non-compliant, I have to believe that the PA PUC would not have approved UGI

Electric's and other EDC plans to date, given that we are now in the fifth cycle of default service plan filings.

Q. Can you provide any other examples?

A. Yes. On pp. 9-11 and elsewhere, Mr. Crist suggests that the UGI Electric GSR-2 PTC rate is variable, both on an hourly basis and for different customers that consume or generate power for export.

While am not an attorney, I am advised by UGI Electric counsel that there is nothing in the AEPS legislation itself nor PA PUC rules and regulations implementing that legislation which require default service PTC rates for large customer generators like Penn Renewables to be a fixed amount over each PTC period. This is discussed further in Ms. Hazenstab's rejoinder testimony.

On p. 13, lines 1-15 of Mr. Crist's testimony, he touts the benefits of customer generation to the distribution grid and suggests related compensation should be provided to customer generators. However, given the intermittent nature of solar production, any such benefit could not be assured for planning purposes and circuits which are near capacity or overloaded will continue to require evaluation for replacement or upgrade; in particular where capacity requirements are driven by winter season peak heating demands (i.e., when there is no sun for production). Also, a plain reading of the AEPS legislation provides for no such compensation mechanism to customer generators.

On p. 15, lines 3-6, Mr. Crist suggests I have claimed that "solar projects will have a negative cost impact on the grid." To the contrary, as all of my testimony and that of

other UGI Electric witnesses carefully explain with significant detail, it is the negative cost impacts on GSR-1 customers that Penn Renewables and other developers' large scale projects will have if shoehorned into a rate designed for residential and small commercial customers up to 100 kW of supply peak load impact.

Q. Are there other statements made by Mr. Crist with which you disagree?

A. Yes, and a few bear mention in this rejoinder. On p. 15, Mr. Crist states that "the generation of energy from a solar facility, while variable, is predictable insomuch as the sun rising and setting are predictable, so managing the generation should not be a burden for UGI."[10]

It goes without saying that the sun beams well above the eastern seaboard and Pennsylvania predictably every day, at various times, depending on the time of the year. However, whether there is cloud cover in between the sun and Pennsylvania, and therefore whether solar projects can reliably convert it to electricity, is not so predictable.

Q. In Mr. Crist's surrebuttal testimony, as part of his critique of hourly wholesale pricing being used as part of a retail GSR-2 PTC rate and the potential that PJM LMPs can go negative at times, he takes issue with my surrebuttal testimony in which I note that large customer generators are sophisticated market participants and that infrequent negative LMPs send a price signal to generators to curtail output.[11] How do you respond?

[10] Penn Renewables Statement No. 1-SR, p. 16, lines 6-9.
[11] See for example, Penn Renewables Statement No. 1-SR, pp. 13 – 14, and p. 16, especially lines 21-23.

A. Mr. Crist appears to suggest that large customer generators and the developers that service them are entirely unaware of changing hourly PJM wholesale market prices.

While that may be the case as a business practice for some of them, the PA PUC should not be persuaded that that provides a valid excuse for forcing these large projects into a small residential and commercial customer default service pool in order to obtain a potentially higher associated GSR-1 PTC rate benefit at the expense of UGI Electric's residential and small commercial customers. Nor should it suggest such large customer-generators can not avail themselves of the same wholesale market information that anyone else has access to. I recently downloaded the ***PJM Now*** cellphone application for free.[12] In a few clicks, I was able to access PPL Zonal LMP data over the last 24 hours, both actual real-time data and day-ahead prices. The ready availability and ease of use of this application demonstrate that Mr. Crist's claims are without merit.

Q. Does this conclude your rebuttal testimony at this time?

A. Yes.

[12] https://www.pjm.com/markets-and-operations/etools/pjm-now

EXHIBIT SCF-1-RJ

Date	Year	Month	Day	Hour	LMP ($/MW)	Negative?
1/18/2020 7:00	2020	1	18	7	(124.96)	1
1/19/2020 4:00	2020	1	19	4	(186.67)	1
1/20/2020 0:00	2020	1	20	0	(19.04)	1
3/2/2020 6:00	2020	3	2	6	(0.60)	1
5/24/2020 23:00	2020	5	24	23	(3.48)	1
6/10/2020 15:00	2020	6	10	15	(13.10)	1
6/14/2020 6:00	2020	6	14	6	(2.44)	1
6/14/2020 7:00	2020	6	14	7	(4.85)	1
6/14/2020 8:00	2020	6	14	8	(3.76)	1
9/25/2020 23:00	2020	9	25	23	(2.53)	1
10/10/2020 7:00	2020	10	10	7	(3.22)	1
1/29/2021 9:00	2021	1	29	9	(19.57)	1
1/29/2021 10:00	2021	1	29	10	(11.87)	1
1/29/2021 11:00	2021	1	29	11	(17.33)	1
1/30/2021 20:00	2021	1	30	20	(0.34)	1
1/30/2021 21:00	2021	1	30	21	(3.86)	1
7/4/2021 7:00	2021	7	4	7	(16.30)	1
1/11/2022 14:00	2022	1	11	14	(171.54)	1
1/11/2022 15:00	2022	1	11	15	(221.96)	1
3/19/2022 7:00	2022	3	19	7	(7.77)	1
5/30/2022 3:00	2022	5	30	3	(9.27)	1
5/30/2022 6:00	2022	5	30	6	(12.48)	1
5/30/2022 7:00	2022	5	30	7	(20.03)	1
11/14/2022 4:00	2022	11	14	4	(11.73)	1
2/4/2023 12:00	2023	2	4	12	(11.08)	1
3/26/2023 13:00	2023	3	26	13	(8.50)	1
4/24/2023 1:00	2023	4	24	1	(5.07)	1
5/7/2023 11:00	2023	5	7	11	(13.73)	1
5/7/2023 12:00	2023	5	7	12	(44.32)	1
5/7/2023 13:00	2023	5	7	13	(14.23)	1
8/3/2023 0:00	2023	8	3	0	(30.93)	1
8/3/2023 11:00	2023	8	3	11	(8.83)	1

8/20/2023 9:00	2023	8	20	9	(0.55)	1
8/20/2023 10:00	2023	8	20	10	(0.48)	1
8/20/2023 11:00	2023	8	20	11	(4.90)	1
8/26/2023 23:00	2023	8	26	23	(2.94)	1
9/3/2023 6:00	2023	9	3	6	(1.71)	1
9/3/2023 7:00	2023	9	3	7	(4.72)	1
9/4/2023 2:00	2023	9	4	2	(2.21)	1
9/4/2023 3:00	2023	9	4	3	(2.78)	1
9/4/2023 4:00	2023	9	4	4	(3.90)	1
9/23/2023 17:00	2023	9	23	17	(2.60)	1
9/23/2023 18:00	2023	9	23	18	(4.98)	1
9/24/2023 17:00	2023	9	24	17	(18.37)	1
9/24/2023 18:00	2023	9	24	18	(3.62)	1
9/26/2023 21:00	2023	9	26	21	(14.57)	1
10/9/2023 3:00	2023	10	9	3	(11.13)	1
11/4/2023 7:00	2023	11	4	7	(3.88)	1
4/27/2024 10:00	2024	4	27	10	(1.01)	1
5/14/2024 5:00	2024	5	14	5	(16.82)	1
5/14/2024 6:00	2024	5	14	6	(4.20)	1
5/15/2024 6:00	2024	5	15	6	(1.29)	1
5/15/2024 23:00	2024	5	15	23	(8.19)	1
5/16/2024 0:00	2024	5	16	0	(10.15)	1
5/16/2024 3:00	2024	5	16	3	(5.75)	1
5/16/2024 4:00	2024	5	16	4	(12.85)	1
5/16/2024 5:00	2024	5	16	5	(32.87)	1
6/2/2024 17:00	2024	6	2	17	(4.88)	1
6/5/2024 6:00	2024	6	5	6	(9.85)	1
6/5/2024 7:00	2024	6	5	7	(25.55)	1
6/16/2024 5:00	2024	6	16	5	(9.40)	1
6/16/2024 6:00	2024	6	16	6	(8.00)	1
6/16/2024 7:00	2024	6	16	7	(69.18)	1
					(35.74)	

# of Hours negative LMP Since 2020	63	Total Hours Over Study Period	39432	Fraction of Negative Hours	0.2%
2020	11		8784		0.1%
2021	6		8760		0.1%
2022	7		8760		0.1%
2023	24		8760		0.3%
2024	15		6456		0.2%

Table 1 - PPL Zonal Real-Time Locational Marginal Prices Since 2020 (UGI Statement 2-RJ)

	No. of Hours Negative LMP	No. of Daylight Hours Negative LMP	Total Hours Over Study Period	Fraction of Negative LMP Hours	Fraction of Negative Daylight LMP Hours
2020 - 2024	63	30	39,432	0.16%	0.08%
2020	11	3	8,784	0.16%	0.03%
2021	6	3	8,760	0.16%	0.03%
2022	7	5	8,760	0.16%	0.06%
2023	24	15	8,760	0.16%	0.17%
2024	15	4	6,456	0.16%	0.06%

EXHIBIT SCF-2-RJ

Question 10

Request:

Reference page 24, lines 1-7 of Mr. Rouland's Rebuttal Testimony. Provide all evidence relied upon by Mr. Rouland when making the claim that "larger customers were deemed by the Commission as more sophisticated and capable of shopping in the market. Provide all date that demonstrates that large customers are more likely to participate in the competitive market, provide all data that demonstrates that larger customers have a negative impact on the ability of utilities to solicit for and obtain reasonably priced default service."

Response:

Please refer to UGI Electric Direct Testimony No. 2, Section VI, pages 23-31 which provides an overview of the load impacts to default service supply and the Company's proposed actions to mitigate the risks and challenges faced by customer shopping and large customer generators. Pennsylvania Code 52 Pa. Code §§ 54.187 and 69.1805 were established by the Commission to implement the originating requirements to implement a commercial and industrial demand split given the impact of large customers on the smaller customer segment. As provided in UGI Electric Direct Testimony No. 2 (page 24 lines 1-7), approximately 50% of GSR-2 customers are shopping for their electricity versus GSR-1 at between 5-7%. This shows that GSR-2 customers are active and engaged with the market, receive spot market pricing, as compared to GSR-1 customers.

Further, numerous stakeholder comments and Commission documents cite the capability of large customers in relation to the competitive energy market. For example, in the Commission Final Order for the Investigation of Pennsylvania's Retail Electric Market: Recommendations Regarding Upcoming Default Service Plans (I-2011-2237952), two parties both explicitly state large customers are more sophisticated in their actions and understanding of the energy market. Further, the Commission seems to agree stating "that expanding hourly-priced service to medium C&I customers may help to mitigate any cross-subsidies between small C&I and medium C&I customers and may facilitate more competitive offerings from EGSs by encouraging competitive market entry", in reference to its Tentative Order. In the Tentative Order the Commission states that medium commercial and industrial customers have experienced robust shopping which "may result in a higher risk premium being priced into default service, which would be passed onto small commercial and industrial customers." To this end, the Commission ultimately passed the aforementioned regulation to implement a threshold for commercial and

Question 10 (Continued)

industrial customers, aiding to mitigate cross-subsidies, risk premiums, and procurement challenges – which UGI Electric ultimately implemented.

Further, the statistics supplied through Penn Renewables Direct Testimony and response to UGI Set I interrogatory questions support the conclusion that large customer generators are more sophisticated and understand the market. Penn Renewables currently has a total of 12 MW nameplate solar proposed in UGI Electric's service territory – effectively utility-scale in size – showing the scale of prospective build and fundamental understanding of the market and subsequent operations within it. As referenced in Penn-IV-6, multiple federal agencies such as the EIA and EPA demarcate the start of "large" or utility-scale generation at 1 MW. As explained in response to PENN-IV-7 and in Direct Testimony, there are 30 such project application submissions in its queue, each between 1-3 MW nameplate and totaling around 22 MW, clearly showing the prospective size and impact as both great and complex, far beyond traditional small customer generator interconnection and operation. Finally, the PA AEPS Act also requires any alternative energy system with a nameplate capacity of 500 kW or more to be explicitly reviewed by and approved by the Commission. The Commission regulations have actually set a threshold below 1 MW for review. This once again shows that the Commission recognizes the need for further review of these complex large customer generator systems.

Prepared by or under the supervision of: James M. Rouland

EXHIBIT SCF-3-RJ

Question 8

Request:

Please add columns on Attachment Penn I-2

a. to include an example for a comparable non-generating GSR-2 customer of similar 1,000 kW load;

b. that demonstrates the PTC if the customer generator, assuming all other factors remain the same, is producing at 100 kw in a given hour; and

c. that demonstrates the PTC if the customer generator is producing at 200 kw in a given hour.

Response:

Please see Attachment PENN-III-8.

Prepared by or under the supervision of: James M. Rouland

UGI UTILITIES, INC. – ELECTRIC DIVISION
GSR-2 CUSTOMER PRICE TO COMPARE EXAMPLE CALCULATION

Line #	Line Item Description for GSR-2 Customer	Example of Hour Net Consumption (kWh)	Example of Hour Net Generation (kWh) /D	Example of Hour Consumption (kWh) Non-Customer Generator	Example of Hour Net Generation (kWh) /D	Example of Hour Net Generation (kWh) /D	
1	kWh (metered value)	100	(1,000)	1,000	(100)	(200)	
2	Applicable hourly EHV Loss percentage (from PJM)	0.6%	0.6%	0.6%	0.6%	0.6%	
3	Total loss percentage with inclusion of 6.5% UGI system loss (L2+6.5%)	7.1%	7.1%	7.1%	7.1%	7.1%	
4	Loss gross up factor (1-L3)	92.9%	92.9%	92.9%	92.9%	92.9%	
5	Grossed up kWh for losses (L1/L4)	108	(1,076)	1,076	(108)	(215)	
6	Applicable hourly deration factor (from PJM)	3.9%	3.9%	3.9%	3.9%	3.9%	
7	Deration factor (1-L6)	96.1%	96.1%	96.1%	96.1%	96.1%	
8	kWh (with deration) (L5*L7)	103	(1,034)	1,034	(103)	(207)	
9	LMP ($/MWh)	$ 40.0000	$ 40.0000	$ 40.0000	$ 40.0000	$ 40.0000	Assumed $40/MWh for example
10	LMP ($/kWh) (L9/1000)	$ 0.0400	$ 0.0400	$ 0.0400	$ 0.0400	$ 0.0400	
11	Total LMP charges (L8*L11)	$ 4.1378	$ (41.3778)	$ 41.3778	$ (4.1378)	$ (8.2756)	
12	PJM allocated charges - PLC based ($/kW) /A	$ -	$ -	$ 0.2597	$ -	$ -	May 2024 avg $/kW value of $1.87
13	PJM allocated charges - NSPL based ($/kW) /B	$ 0.6375	$ 0.6375	$ 1.2750	$ 0.6375	$ 0.6375	May 2024 avg $/kW value of $9.18
14	PJM allocated charges/(credits) - kWh based ($/kWh)	$ (0.0076)	$ (0.0076)	$ (0.0076)	$ (0.0076)	$ (0.0076)	May 2024 avg $/kWh value
15	Total PJM allocated charges/(credits) - kWh based (L8*L14)	$ (0.7862)	$ 7.8618	$ (7.8618)	$ 0.7862	$ 1.5724	
16	DSP A&G allocated costs - kWh based ($/kWh)	$ 0.0070	$ 0.0070	$ 0.0070	$ 0.0070	$ 0.0070	May 2024 avg $/kWh value
17	Total DSP A&G allocated costs - kWh based (L8*L16)	$ 0.7241	$ (7.2411)	$ 7.2411	$ (0.7241)	$ (1.4482)	
18	Net Metering Purchase Reconciliation /C (charge/(credit)*L8) ($/kWh)	$ -	n/a	$ -	n/a	n/a	
19	Total GSR-2 (L11+L12+L13+L15+L17+L18) excluding GRT	$ 4.7132	$ (40.1197)	$ 42.2919	$ (3.4382)	$ (7.5139)	
20	Total GSR-2 charges including GRT (L19/(1-5.9%))	$ 5.0087	$ (42.6351)	$ 44.9435	$ (3.6538)	$ (7.9850)	
21	STAS (currently 0%)	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Total PTC-2 (L20*(1+L21))	$ 5.0087	$ (42.6351)	$ 44.9435	$ (3.6538)	$ (7.9850)	
23	Unit PTC-2 (per kWh) (L22/L8)	$ 0.0484	$ 0.0412	$ 0.0434	$ 0.0353	$ 0.0386	

/A - Assumes PLC value of zero (net generation during all PLC hours) for customers with usage of 100 kWh, (1,000) kWh, (100) kWh & (200) kWh and a PLC of 100 kW for customer with usage of 1,000 kWh.
/B - Assumes NSPL value of 50kW (net consumption on 50% of NSPL hours) for all scenarios except for customer with usage of 1,000 kWh which utilizes an NSPL value of 100kW (indicative of 100kW load during all NSPL hours).
/C - Assumes no current reconciliation charges/(credits)
/D - Values shown in Line 1 for generating customers are representative of net production over an hourly period

EXHIBIT SCF-4-RJ

Question 7

Request:

Reference page 24, line 11-18 of Mr. Rouland's Rebuttal Testimony. Identify the real and substantial impacts to "portfolio risk if large customer generators are interconnected and serviced under GSR-1. Quantify each and every such risk that is alleged.

Response:

Please refer to UGI Electric Direct Testimony No. 2, Section IV, pages 26 lines 16-23 through page 31 lines 1-2 which provides a qualitative and quantitative explanation of the impact of large customer generators on GSR-1 supply and the Company-proposed solution. As discussed in UGI Electric testimony, variability of supply and associated risks translate to risks in bid prices and supplier interest and participation in UGI Electric solicitations. It is wholly impossible to quantify these exact values (supplier-defined risks and associated costs) as they are based upon each wholesale supplier's evaluation of actual and perceived risks, supplier books of business, resulting choice to participate (or not) in a solicitation, and if bidding, the resulting bid price and bid premiums. Supplier bid components are proprietary and confidential and is not accessible to UGI Electric. That said, there are indirect indicators of these risks translating to results such as low supplier participation in DSP IV FPFR auctions and perceived higher contract prices.

Beyond price, the quantifiable impacts to the GSR-1 products are to tranche sizing and supply. In UGI Electric Direct Statement No. 2, p 15 lines 12-15, the Company's GSR-1 PLC ranged from 138-142 MW or an average of 140 MW. Following the removal of the 20 MW ATC Block, 120 MW of FPFR supply remains, divided over two contracts or tranches – 60 MW each. It is this FPFR supply that is directly impacted by large customer generator export. Penn Renewables has communicated they currently have 12 projects in queue with UGI Electric, each between 1-2 MW nameplate or with an expected operating capacity of approx. 0.9 MW per MW nameplate. These 12 projects collectively amount to approximately 12.6 MW of operating capacity, or equating to 10.5% of total tranche size. Stated more clearly, Penn Renewable projects alone are projected to reduce the tranche size for wholesale FPFR suppliers by approximately 10.5%.

Further, as explained in UGI Electric Direct Statement No. 2, p 27 lines 13-24 and p. 28 lines 1-4, Penn Renewables is not the only developer seeking to interconnect large customer generators to UGI Electric's system. The potential impact from large customer generators could be substantially larger, with 30 project applications received at the time

Question 7 (Continued)

of the Company's filing totaling 22 MW nameplate or 19.8 MW operating capacity. This reduces tranche size by approximately 16.5%. These values are not insignificant. Adding additional supply risk from large customer generators to the GSR-1 customer pool only increases supplier risk, likely impacting supplier participation and increases bid price. This subsequently translates to higher costs for customers and an even higher subsidy paid to these same large customer generators.

Prepared by or under the supervision of: James M. Rouland

EXHIBIT SCF-5-RJ

Question 30

Request:

If UGI used all customer generation for system supply, would it reduce power supply procured from PJM?

Response:

Please refer to the response to PENN-III-29 which explains that the GSR-1 and GSR-2 rate groups are managed separately. GSR-1 energy and related services primarily consist of contracted fixed price full requirements load following contracts and block, energy-only contracts. Net metering customers on GSR-1 that export energy effectively, reduce the amount of energy procured from wholesale suppliers provided GSR-1 service. GSR-2 energy and related services are procured directly from PJM. Net metering customers on GSR-2 that export energy effectively, reduce the amount of energy procured through PJM for GSR-2 customers.

Prepared by or under the supervision of: James M. Rouland

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division For Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029	: : : :	Docket Nos. P-2024- G-2024-

---

PETITION OF UGI UTILITIES, INC. – ELECTRIC DIVISION FOR APPROVAL OF A DEFAULT SERVICE PLAN

TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION:

Pursuant to Section 2807 of the Pennsylvania Public Utility Code, 66 Pa. C.S. § 2807, and the regulations of the Pennsylvania Public Utility Commission ("Commission" or "PUC") at 52 Pa. Code §§ 54.181-54.190 ("Default Service Regulations"), UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") hereby requests approval of its fifth Default Service Plan ("DSP V" or the "Plan"). The Plan establishes the terms and conditions under which the Company will acquire default service supplies, including Alternative Energy Portfolio Standards ("AEPS") credits, from June 1, 2025, through May 31, 2029 ("DSP V Term"). It employs a prudent mix of electric supplies (e.g., spot market purchases, short-term contracts, and long-term contracts) obtained through competitive bid solicitation processes (e.g., auctions, requests for proposals and/or bilateral agreements). Consequently, the Company's default service customers will receive adequate and reliable service at the least cost over time.[1] Additionally, UGI Electric requests that the Commission:

[1] This aligns with the Commission's goal for the Default Service Regulations - to ensure that each default service provider delivers adequate and reliable service at the least cost over time (as stated in 52 Pa. Code § 69.1802).

1. Approve potential affiliated interest transactions associated with DSP V pursuant to Section 2102 of the Public Utility Code, 66 Pa. C.S § 2102; and

2. Approve the Company's DSP V Plan no later than the Commission's last public meeting in January 2025, if possible, to provide sufficient time to implement the procurement strategy in DSP V prior to the expiration of the current DSP IV plan on May 31, 2025, for purchases beginning June 1, 2025 without the need for modification of procurement timing.

Through its DSP V Petition, the Company will (1) procure a competitive mix of default service supplies through load-following, block and spot market purchases, and related AEPS credits over the 4-year DSP V Term (i.e., 2025-2029); (2) implement a procurement schedule designed to obtain these supplies at the least cost; (3) issue Requests for Proposals ("RFPs") seeking default supply in accordance with the agreements and forms included with this Petition; (4) adopt a contingency plan[2] that addresses any procurement target shortfalls; (5) recover all incurred default service costs on a full and current basis through a specified default service rate design; (6) adopt revised tariff rules clarifying the application of GSR-1 and GSR-2 default service rate classifications; and (7) continue the retail enhancement programs adopted in DSP IV.

As noted herein, the Company is clarifying the GSR-1 and GSR-2 rate groupings to classify customers according to their supply peak load impact. This approach will better align larger net-metering customer-generators with larger customers that have similar grid impacts.

[2] A default service plan must contain contingency plans to address situations where a wholesale generation supplier does not meet its contractual obligation to provide electric supply to default service providers. 52 Pa. Code § 54.185(d)(5).

I. INTRODUCTION

1. UGI Electric is a "public utility", an "electric distribution company" ("EDC") and a "default service provider" as defined in Sections 102 and 2803 of the Public Utility Code, 66 Pa. C.S. §§ 102, 2803.

2. UGI Electric provides electric distribution service to approximately 62,000 customers in portions of two northeastern Pennsylvania counties (Luzerne and Wyoming Counties), and since the expiration of its generation rate cap in 2002, has served as the default service provider for its electric distribution system.

3. UGI Electric's address is UGI Utilities, Inc., 1 UGI Drive, Denver, PA 17517.

4. UGI Electric's attorneys are:

Lindsay Berkstresser (ID # 318370)
Counsel, Energy & Regulatory
UGI Corporation
500 North Gulph Road
King of Prussia, PA 19406
Tel: 717-504-9925
E-mail: berkstresserl@ugicorp.com

Anthony D. Kanagy (ID # 85522)
Nicholas A. Stobbe (ID # 329583)
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101-1601
Tel: 717-731-1970
E-mail: akanagy@postschell.com
nstobbe@postschell.com

Devin T. Ryan (ID # 316602)
Post & Schell, P.C.
One Oxford Centre
301 Grant Street, Suite 3010
Pittsburgh, PA 15219
Tel: 717-612-6052
E-mail: dryan@postschell.com

II. LEGAL AUTHORITIES

A. STATUTORY REQUIREMENTS

5. On December 3, 1996, Governor Tom Ridge signed into law the Electricity Generation Customer Choice and Competition Act ("Competition Act"). The Competition Act revised the Public Utility Code, 66 Pa. C.S. §§ 101, *et seq.*, by, inter alia, adding Chapter 28, relating to restructuring of the electric utility industry. Chapter 28 provided for an orderly transition of the Pennsylvania electric industry from a vertically integrated monopoly to a structure which would support the development of a competitive retail electric generation market. The ultimate goal was to permit all Pennsylvania retail electric customers to have direct access to a competitive generation market, while simultaneously enjoying the continued reliability, and safety of existing transmission and distribution services. The Competition Act became effective on January 1, 1997.

6. The Alternative Energy Portfolio Standards Act of 2004, P.L. 1672, No. 213, ("AEPS Act") was signed into law on November 30, 2004. 73 P.S. §§ 1648.1, *et seq.* The AEPS Act, which took effect on February 28, 2005, established an alternative energy portfolio standard for Pennsylvania. Generally, the Act requires that an annually increasing percentage of electricity sold to retail customers in Pennsylvania by EDCs and electric generation suppliers ("EGSs") be derived from alternative energy resources.

7. On October 15, 2008, Governor Edward Rendell signed House Bill 2200, Act 129, into law. Act 129 became effective on November 14, 2008. It has several goals including reducing energy consumption and demand. It also revised the default service requirements contained in Chapter 28 of the Public Utility Code (i.e., the Competition Act). Act 129 of 2008, P.L. 1592.

8. As such, Section 2807(e) of the Competition Act now requires each EDC to provide default service to retail customers within its certificated territory when either a chosen EGS does not do so or when customers otherwise do not choose to receive service from an EGS. Pursuant to Act 129, electric power shall be procured through competitive procurement processes and shall include one or more of the following: (1) auctions; (2) requests for proposals; or (3) bilateral agreements. 66 Pa. C.S. § 2807(e)(3.1). The electric power that is procured shall include a prudent mix of: (1) spot market purchases; (2) short-term contracts; and (3) long-term purchase contracts of more than 4 and not more than 20 years. 66 Pa. C.S. § 2807(e)(3.2). In addition, 66 Pa. C.S. § 2807(e)(3.3) made it clear that all energy purchased by a default service provider must be competitively procured, including AEPS credits associated with energy generated from qualifying alternative resources at the levels specified in the AEPS Act.

9. The "prudent mix" of contracts shall be designed to ensure: (1) adequate and reliable service; (2) the least cost to customers over time; and (3) compliance with the procurement methodologies described above, i.e., through auctions, RFPs; or bilateral agreements. 66 Pa. C.S. § 2807(e)(3.1).

10. Regarding process, default service providers must file a plan for competitive procurement with the Commission and obtain Commission approval of the plan considering certain factors and standards contained in Section 2807(e) before competitive procurements may be implemented.

11. When evaluating a default service plan, the Commission must consider the EDC's obligation to provide adequate and reliable service to the customers. The Commission also must determine that the EDC has obtained a prudent mix of contracts at

the least cost on a long-term, short-term, and spot market basis. The Commission is required to make specific findings when reviewing DSPs: (1) the DSP includes prudent steps necessary to negotiate favorable generation supply contracts; (2) the DSP includes prudent steps necessary to obtain least cost generation contracts on a long-term, short-term and spot market basis; and (3) neither the default service provider nor its affiliated interest has withheld generation supply from the market as a matter of federal law. 66 Pa. C.S. § 2807(e)(3.7).

12. Further, Act 129 revised the Competition Act giving default service providers a right to recover default service costs pursuant to a reconcilable automatic adjustment clause. It also stated that residential and small commercial customers rates cannot change more frequently than quarterly. 66 Pa. C.S. § 2807(e)(7).

13. To implement the statutory requirements of the Competition Act, the AEPS Act and Act 129, the Commission adopted Default Service Regulations at 52 Pa. Code §§ 54.181-54.190, a Default Electric Service ("DES") Policy Statement at 52 Pa. Code §§ 69.1801-69.1817 ("DES Policy Statement") and provided guidance for default service plans through various Electric Retail Markets Investigation ("RMI") Orders at Docket No. I-2011-2237952.

B. DEFAULT SERVICE REGULATIONS

14. The Commission's Default Service Regulations set forth the obligations of EDCs to serve as default service providers. Section 54.183 states that the incumbent EDC

shall serve as the default service provider until and unless an alternative provider is approved by the Commission.[3]

15. Sections 54.184 through 54.186 set forth the framework through which customers have access to generation supply. Section 54.184 states that the default service provider, acting in the default service function, shall serve customers when either a chosen EGS does not do so or when customers otherwise do not choose to receive service from an EGS (similar to the requirements set forth in 66 Pa. C.S § 2807(e)(3.1)). Additionally, a default service provider must file a DSP with the Commission no later than 12 months prior to the conclusion of the currently effective program (per 52 Pa. Code § 54.185(a)). After the first DSP, the term of subsequent programs shall be determined by the Commission. 52 Pa. Code § 54.185(d).[4]

16. Section 54.186 states what DSPs must accomplish and the standards they must follow. More specifically, DSPs must acquire generation supply at the least cost to customers over time (similar to the requirements of 66 Pa. C.S. § 2807(e)(3.3)(ii)). According to 52 Pa. Code § 54.186 (b)(1)(i)-(iii), DSPs also must include procurement plans, which acquire a prudent mix of resources, including spot market purchases, short-term contracts, and long-term contracts (like the requirements set forth in 66 Pa. C.S. § 2807(e)(3.2)(i)-(iii)). As specified in 52 Pa. Code § 54.186(b)(5), DSPs must obtain electric generation supplies through competitive bid solicitation processes (akin to the requirements set forth in 66 Pa. C.S. § 2807(e)(3.1)). The specific competitive bid

[3] The Commission confirmed this much in its *Investigation of Pennsylvania's Retail Market: End State Default Service*, Docket No. I-2011-2237952 (Final Order entered February 15, 2013). Based on its review of industry feedback in Docket No. I-2011-2237952, the Commission was "persuaded to adopt [its] initial proposal to retain the EDC in the DSP role." *Id.* at 20.

[4] The DES Policy Statement at 52 Pa. Code § 69.1804 suggests using a DSP term of two to three years, unless otherwise approved by the Commission.

processes that default service providers must adhere to are detailed in 52 Pa. Code § 54.186(c).

17. Additionally, Section 54.187 specifies the means by which EDCs may recover costs for engaging in the default service function. According to 52 Pa. Code § 54.187(b), costs incurred in providing default service shall be recovered on a full and current basis through a Section 1307 reconcilable adjustment clause, including costs for complying with the AEPS Act as stated in 52 Pa. Code § 54.187(f). These regulations are similar to the statutory requirements set forth in 66 Pa. C.S. § 2807(e)(3.9).

C. THE COMMISSION'S DES POLICY STATEMENT

18. The Commission's DES Policy Statement (at 52 Pa. Code §§ 69.1801 – 69.1817) became effective on September 15, 2007. As specified in Section 69.1802, the goal of the Commission's default service regulations is the provision of adequate and reliable service to default service customers at the least cost over time. The DES Policy Statement's guidelines provide the flexibility needed for default service providers to achieve this goal through their DSPs.

19. According to 52 Pa. Code § 69.1805, default service providers have the flexibility to seek a prudent mix of supply-side and demand-side resources (such as long-term, short-term, staggered-term and spot market purchases) to minimize contracting for supply at times of peak prices.

20. Regarding the cost of default service, Section 69.1808 states that the EDC's price to compare ("PTC") should recover all generation and transmission costs including: wholesale energy, capacity, ancillary, Retail Transmission Organization ("RTO") administrative and transmission costs, congestion costs, supply management costs, administrative costs, applicable taxes and AEPS compliance costs.

21. Per Section 69.1809, default service rates and the PTC may not be adjusted more frequently than quarterly to reflect changes in wholesale energy and related costs and to reconcile over- and under-collections. Default service costs and revenues should be reconciled as part of the PTC adjustment process.

22. In addition, Section 69.1815 requests the inclusion of customer referral programs[5] in DSPs.

D. THE COMMISSION'S ELECTRIC RMI ORDERS

23. Beginning with its Order in the Investigation of Pennsylvania's Retail Electricity Market at Docket No. I-2011-2237952, which was entered on April 29, 2011, the Commission initiated an Electric RMI proceeding to address and resolve retail market issues identified by the Commission. In the Electric RMI proceeding, the Commission issued a number of Orders that impacted DSPs.[6]

24. In its December 16, 2011 Electric RMI Order, the Commission confirmed that EDCs should: 1) limit or eliminate short-term contracts that extend beyond the end of the DSP period; and 2) limit the proportion of long-term contracts and consider using already-existing ones. (December 16, 2011 RMI Order at 19). The Commission also reiterated that it will not prescribe specific contract durations for default service procurements. (*Id*. at 19-20). The December 16, 2011 RMI Order further permitted EDCs to use a laddering approach such that supply purchases occur at different times and with

[5] Infra at pp. 11-12.

[6] *See Investigation of Pennsylvania's Retail Electricity Market: Recommendations Regarding Upcoming Default Service Plans*, Docket No. I-2011-2237952 (Final Order entered December 16, 2011) ("December 16, 2011 RMI Order"); *Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan*, Docket No. I-2011-2237952 (Final Order entered March 2, 2012) ("March 2, 2012 RMI Order"); *Investigation of Pennsylvania's Retail Market: End State Default Service*, Docket No. I-2011-2237952 (Order entered February 15, 2013) ("February 15, 2013 RMI Order") (collectively "Electric RMI Orders").

overlapping delivery periods. (*Id*. at 20-21). Here, the Commission further clarified that EDCs do not need long-term contracts for AEPS credit solicitations.

25. The Commission entered a Tentative Order in Docket No. I-2011-2237952 on November 8, 2012.[7] It requested that EDCs offer hourly Locational Marginal Pricing ("LMP") to medium and large commercial and industrial customers (with demands of 100 kW or greater). (November 8, 2012 Tentative Order at 16-17).[8]

26. Additionally, in the November 8, 2012 Tentative Order, the Commission proposed fixed, quarterly, PTCs for residential and small commercial customers. The Commission envisioned the enactment of quarterly auctions to procure all default service load for these residential customers through tranches of full requirements, load-following contracts. (*Id*.). Similarly, the auctions would occur one to two months before the beginning of the delivery date for the upcoming quarter. (*Id*.).

27. In its March 2, 2012 RMI Order, the Commission determined that DSPs should include two types of Customer Referral Programs: New/Moving Customer and Standard Offer. (March 2, 2012 RMI Order at 13-33). New/Moving Customer Referral Programs provide residential and small commercial customers with basic information on shopping during calls to initiate service and calls to move service to a new address. (*Id*. at 17-18).

[7] *See Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952 (Tentative Order entered November 8, 2012) ("November 8, 2012 Tentative Order).

[8] The Commission explained the reasoning behind the 100 kW threshold in its October 14, 2021 Tentative Order at Docket No. I-2011-2237952, stating that "[c]urrently, a significant level of electric shopping occurs for medium sized commercial and industrial customers, generally those customers with demand greater than 100 kW." (October 14, 2011 Tentative Order at 8). "This robust level of shopping by medium commercial and industrial customers may result in a higher risk premium being priced into default service, which would be passed onto small commercial and industrial customers." (Id.).

28. In its December 16, 2011 RMI Order, the Commission stated that it would consider DSPs with quarterly, semi-annual, or annual reconciliation periods. (December 16, 2011 RMI Order at 54). The Commission also instructed EDCs to include clear descriptions of how quarterly changes in supply charges would be calculated, adjusted, reconciled, and allocated among default service rate classes. (*Id.*).

29. As explained herein, UGI Electric's Petition and proposed DSP V are designed in accordance with the Commission's DES regulations, DES Policy Statement, and Electric RMI Orders.

III. UGI ELECTRIC'S PROPOSED PLAN – DSP V

A. INTRODUCTION

30. In this proceeding, the Company seeks to implement its DSP V Plan during the four-year period between June 1, 2025 and May 31, 2029. The Commission's DES Policy Statement (at 52 Pa. Code § 69.1804) suggests using a DSP term of two to three years, unless otherwise approved by the Commission. The Commission approved a four-year term for the Company's DSP III Plan and DSP IV Plan. In addition, the Commission has approved four-year default service plans for all of the large EDCs in Pennsylvania, including PPL Electric Utilities Corporation, Duquesne Light Company, the FirstEnergy Companies (now FirstEnergy Pennsylvania Electric Company), and PECO Energy Company. UGI Electric seeks the same allowance to implement its DSP V over a four-year term.

31. In accordance with 52 Pa. Code § 54.185(e)(1), the Company's DSP V includes a procurement plan, which identifies a supply acquisition strategy for use during the proposed plan period (June 1, 2025 through May 31, 2029). The DSP V Plan also

identifies the means by which the Company will satisfy the minimum portfolio requirements set forth in the AEPS Act.

32. The Company developed its proposed DSP V Plan to be similar to the procurement plans utilized by other EDCs in Pennsylvania, with a general movement from the DSP IV plan in a manner to optimize procurement activities. The Company has identified that other EDCs rely almost entirely on a laddered mix of fix priced full requirements ("FPFR") contracts for their residential and small commercial customers, with some including longer term block purchases. UGI Electric intends to follow a similar approach in its DSP V procurement plan for GSR-1 customers.

33. Historically, the Company has relied on a combination of block and full requirements contracts, as well as some spot purchases, to procure supplies for GSR-1 customers. As explained by UGI Electric witness James M. Rouland, UGI Electric Statement No. 2, under the DSP IV Plan, the Company experienced limited bidder participation and higher risk premiums for its full requirements contracts. For DSP V, the Company is taking significant steps to reduce the risk for its FPFR contracts, both in how it is adjusting its product mix and in how the RFP and contract terms are being adjusted. The Company also determined that increased supplier risk premiums are due, in part, to the inclusion of non-market-based transmission costs. Therefore, UGI Electric is proposing to remove those costs from its full requirements contracts, similar to the treatment of these costs by other EDCs. Additionally, the Company is proposing to provide full requirements suppliers with guidance on PJM Interconnection LLC ("PJM") capacity pricing in the event such prices are not available or final. This guidance will allow bidders

to make an informed bid with a defined capacity price, and if the actual capacity price differs from that used in the bid, UGI Electric will settle the difference with the supplier.

34. As discussed in greater detail later in this petition, UGI Electric is proposing changes to its block and full requirements products to reduce risk. The Company is implementing a fixed MW around-the-clock block product which will add price stability to the default service supply mix and limit risk to full requirements suppliers by predefining the block amount. The block product will also replace the 24-month full requirements product from DSP IV. This shift will result in a higher MW amount for the 12-month full requirements products in this plan, providing greater supply and improved stability to suppliers and customers alike. Collectively, these efforts will aid in the reduction of supplier risk, likely improve the attractiveness of full requirements and block product supplies to suppliers, improve competition, and hopefully lower associated premiums.

B. DSP V CUSTOMER RATE CLASSIFICATIONS

35. The Company's default supply acquisition strategy for DSP V will continue to identify customers by GSR-1 and GSR-2 customer groupings, as was done in DSP IV. However, in DSP V, UGI Electric is clarifying that these groupings are determined by the supply peak load impact of the customer, with GSR-1 applying to those customers with a supply peak load impact below 100 kW, and GSR-2 applying to those customers who have a supply peak load impact that is greater than or equal to 100 kW. This approach includes reviewing net metering customer-generators based upon their net supply peak load impact, with resulting separation of portfolio risk management and costs impacts to default service procurement activities. The uniform application of a 100 kW threshold addresses possible small versus medium/large cross-subsidy concerns and provides clarity for all customers.

C. GSR 1 PROCUREMENT STRATEGY FOR DSP V

36. The Company will procure its estimated annual supply for GSR-1 customers through several procurement types: 1) ATC block product Bids; 2) GSR-1 Full Procurement Full Requirements ("FPFR") Load-Following Service Bids; and 3) the long-term arrangement between UGI Electric and the Allegheny Electric Cooperative, Inc. ("Allegheny").[9] Additionally, UGI Electric intends to acquire alternative energy credits in association with certain supply purchasing activity necessary for compliance with state AEPS obligations through a competitive procurement. The Company will also acquire necessary spot energy, capacity and ancillary services through the PJM markets as necessary.

37. Included in Appendix C, the direct testimony of UGI Electric witness James M. Rouland, UGI Electric Exhibit JMR-2 provides an overview of the proposed product procurements and schedule.

38. Since there is a relatively small percentage of overlap in products from DSP IV to DSP V, the Company proposes to procure a majority of the portfolio's supply in Solicitation 1. This is described by Mr. Rouland in UGI Electric St. No. 2. After Solicitation 1, UGI Electric will transition into its steady state procurements for the remainder of DSP V.

1. GSR-1 Block Purchase Bids for DSP V

39. In DSP IV, the Company procured a mix of single-month contracts through ATC and peak block purchase bids. Each bid round, one in Spring and Fall of each Plan

[9] Allegheny has been reselling power procured from New York to UGI Electric pursuant to the *Agreement of Electric Service* ("Allegheny Agreement"), which has been in place since January 5, 2004.

year, sought block supplies to be delivered over 6-month periods in an amount of 25% of the total GSR-1 load needed during each month of the 6-month period. The Company issued RFPs seeking 5x16 energy blocks and 7x24 energy blocks. For each of these block products, the 6-month period was awarded on an individual month basis, with a varying amount of load identified for each of the months in the 6-month period.

40. For DSP V, once in steady-state, the base of the GSR-1 portfolio will consist of 20 MW of around the clock ("ATC") block supply. There will be two staggered tranches of ATC block contracts. Each of the blocks will be for 10 MW of load and will be for a 24-month term.

41. For the first block tranche, a 10 MW ATC block contract will be procured in an auction to be held between January and March 2025 for service beginning June 1, 2025, through May 31, 2027. An additional 10 MW ATC block contract will be procured in an auction to be held between January and March 2027 for service beginning June 1, 2027, through May 31, 2029, which coincides with the end of the DSP V Term.

42. For the second block tranche, a 10 MW ATC block contract will be procured in an auction to be held between January and March 2026 for service beginning June 1, 2026, through May 31, 2028. An additional 10 MW ATC block contract will be procured in an auction to be held between January and March 2028 for service beginning June 1, 2028, through June 1, 3030. This contract will extend past the DSP V Term and will provide rate stability and a transition period for GSR-1 customers as the Company moves into the DSP VI period. The Commission has approved over-hanging contracts (i.e., contracts that extend from one DSP period to the next) for other EDCs in Pennsylvania.

43. By staggering the 24-month ATC 10 MW block contracts, the Company will provide longer term rate stability for GSR-1 customers than is currently provided under the DSP IV plan. Further, as described in the testimony of UGI Electric witness Mr. Rouland, the transition to longer term fixed load block products is expected to improve the marketability of the full requirements contracts by creating a more stable and forecastable load that would be covered by those contracts.

2. GSR-1 Full Requirements Load-Following Service Bids for DSP V

44. In DSP IV, the Company procured a mix of 12-month and 24-month FPFR contracts for approximately 75% of its total default service supply obligation. These contracts had a relatively small MW size, with few bidders participating and higher than desired premiums for these contracts.

45. UGI Electric is aware that all the larger EDCs in Pennsylvania rely primarily on FPFR contracts to provide default supply for residential and small commercial customers. In DSP V, the Company seeks to procure more supply for its GSR-1 customers through FPFR contracts and is taking significant steps to encourage more bidder participation by increasing the total load served by each awarded contract and reducing supplier risks through the fixed block products and by removing non-market-based transmission costs from the pricing. UGI Electric expects that increased competition and reduced risk will reduce the premiums ultimately borne by the Company's GSR-1 customers.

46. In DSP V, once the Company reaches a steady state, it will procure two tranches of 12-month FPFR contracts. Each contract will be for 50% of FPFR supply above the 20 MW ATC block purchases, the Allegheny Agreement purchases discussed

below, and customer-generation purchased by the Company through its net metering program. The 12-month FPFR contracts will be staggered at 6-month intervals. The 12-month FPFR contract for the first tranche will be procured in an auction to be held between January and March 2025 for supply beginning June 1, 2025 through May 31, 2026. New 12-month FPFR contracts will be procured in annual auctions held between the January and March period for service beginning June 1 so that there are continuing 12-month FPFR contracts for the first tranche.

47. For the second FPFR tranche, the Company will procure a 12-month FPFR contract in an auction to be held between July and September 2025 for service beginning December 1, 2025 through November 30, 2026. New 12-month FPFR contracts will be procured in auctions to be held between the July and September period for service beginning December 1 so that there are continuing 12-month FPFR contracts for the second tranche. The procurement methodology is described in more detail in UGI Electric St. No. 2 and accompanying exhibits.

48. The 12-month FPFR contracts for both tranches will overlap to provide rate stability for GSR-1 customers. In addition, the last 12-month FPFR contract for the second tranche will overhang 6 months into the DSP VI period, which also will provide GSR-1 customers with rate stability going into the DSP VI period to avoid a hard stop and hard start between the end of DSP V and the beginning of DSP VI.

49. The Company is proposing to provide a more reliable competitive product for customers through improved supplier participation, defined competitive procurement events, and increased supplier diversity. Improved supplier diversity is achieved through a FPFR tranche cap, limiting the number of suppliers that can be awarded FPFR tranches to

one supplier for a single 12-month tranche. By implementing a fixed MW ATC block product, FPFR suppliers will have pre-defined block terms throughout the course of the contract term, limiting the risk that block supply could rise or fall and therefore impacting the supply amount and associated premiums for that supply. The Company is also providing FPFR suppliers with guidance on PJM capacity pricing in the event such prices are not final, also limiting the supplier risk during bidding and throughout the contract term. Finally, as previously discussed, UGI Electric will pull back NMB costs from FPFR suppliers, again reducing the risk associated with cost components that needlessly increase supplier risk premiums or that make FPFR less desirable.

3. Allegheny Agreement Purchases for DSP V

50. A small portion of the Company's default service load for DSP V will continue to be acquired through the long-term arrangement between UGI Electric and the Allegheny Electric Cooperative, Inc. ("Allegheny") as was done in DSP III and DSP IV. The history of this arrangement can be found in the testimony of Mr. Rouland. In short, Allegheny purchases generation from the Power Authority of the State of New York ("NYPA") in bulk and resells it to various Pennsylvania counterparties (one of which is UGI Electric).[10] During each year of DSP V, Allegheny will provide UGI Electric with an allocated share of hydroelectric power generated in New York and obtained from NYPA. UGI Electric's allocated share is currently set at 2.6409% of the total amount that Allegheny purchases from NYPA and distributes to the various Pennsylvania counterparties under the Agreement. NYPA will likely revise this percentage during the

[10] Allegheny purchases this electric generation from New York through the currently effective *Agreement for the Sale of Saint Lawrence-FDR Project Power and Energy to Allegheny Electric Cooperative, Inc*. (between NYPA and Allegheny).

term of DSP V. Historically, these updates/revisions have been limited in nature. Pursuant to the terms of the Agreement between UGI Electric and Allegheny, the Company will abide by the revised percentages set by NYPA. These procurements will continue to be included as a generation supply source in the Company's DSP V and will be recovered through the Company's GSR-1 rate (Rider B – Generation Supply Service Surcharge) in the same manner as occurred in DSP III and DSP IV.

D. GSR-2 (LMP) PROCUREMENTS FOR DSP V

51. UGI Electric currently has approximately 100 GSR-2 default service customers. These customers have a combined peak load of more than 13.9 MW. For DSP V, the GSR-2 group will consist of customers with a supply peak load impact of 100 kW or greater. This is similar to the customers included in GSR-2 in DSP III and DSP IV, although the Company proposes in this filing to provide greater clarity as to how this rate will be applied for customer-generator accounts.

52. For DSP V, consistent with DSP III and DSP IV, the Company proposes to acquire and apply PJM's real-time hourly market pricing for supply.

53. For these procurements, the Company will be responsible for acquiring any necessary capacity, transmission to UGI Electric's system, ancillary services, congestion management services, AEPS credits and such other services or products as are necessary to provide default service to these customers as well as accommodate any required net metering purchases.

E. NET METERING PURCHASES

54. UGI Electric currently has 30 new applications for net metering systems to be installed in the Company's service territory within the next 3 years. Related to GSR-1 versus GSR-2 service criteria, 16 of these installations will have default supply impacts

under 100 kW that will impact GSR-1, and 14 will have default supply impacts greater than 100kW that impact GSR-2. The facilities impacting GSR-1 will provide up to 186kW of generation, whereas the 14 facilities classified as GSR-2 will provide up to 22 MW of generation. It is possible during the DSP V Term – June 2025 through May 2029 – that additional requests may be filed, or some of these proposed installations will not be completed. While the final total impact of these systems is unclear, the Company is positioning its default supply portfolio to accommodate what may be a significant increase in net metering in a way that is seamless and will appropriately address impacts and costs for default service customers.

55. As part of its review of its portfolio and default service rate structure, UGI Electric is proposing to recognize the impact that customers have on the Company's default supply activities. Specifically, where a customer's (including a net metering customer's) supply peak load impact is less than 100 kW, that customer will be included in GSR-1. Where a customer's (including a net metering customer's) supply peak load impact is greater than or equal to 100 kW, that customer will be included in GSR-2.

56. The Company's GSR-1 procurement portfolio will accommodate and address the potential fluctuation in participating GSR-1 net metering through adjustments in the total load covered by the FPFR contracts, and those net metering customers will be paid for excess generation at the price to compare applicable to GSR-1 customers.

57. GSR-2 net metering will reduce the total PJM spot market purchases made on behalf of the Company's other GSR-2 customers. Where the total net metering generation exceeds GSR-2 demand at any point in time, excess generation will be sold back to PJM. GSR-2 net metering customers will be paid for excess generation at the price-to-

compare applicable to GSR-2 customers. The tariff modifications to effectuate this change are explained in Ms. Hazenstab's testimony, UGI Electric Statement No. 3.

F. AEPS CREDITS FOR GSR-1 AND GSR-2

58. Consistent with DSP III and DSP IV, the Company will procure AEPS credits (in accordance with Section 75.61(b)(15)) for each plan year as specified below:

59. For the June 1, 2020, through May 31, 2021 reporting period (and each successive 12 months thereafter), the Tier I requirement is 8% of all retail sales, of which at least 0.5% of all retail sales are to come from solar generation and the remainder from non-solar Tier I resources. The Tier II requirement is 10% of all retail sales. For GSR-1 load-following supplies, the load-following suppliers will be responsible for obtaining AEPS credits in an amount that corresponds to the amount of retail sales for the relevant load-following delivery period.

60. UGI Electric will procure AEPS credits for its remaining GSR-1 default service procurements and all of its GSR-2 default service procurements through an RFP process similar to DSP IV.[11]

61. The Company proposes using the same AEPS agreement that was approved by the Commission's January 22, 2009 Order (approving the *Joint Petition for Settlement of UGI Electric's AEPS Plan* at Docket Nos. P-2008-2063006 and G-2008-2063688). This AEPS agreement form was used in the Company's DSP III and DSP IV Plans.

62. Under the AEPS Act, the Company's compliance obligations are measured on a Reporting Period basis as defined in 52 Pa. Code § 75.1. This consists of the 12-

[11] The Company will issue an RFP to procure these AEPS credits based on sales estimates, which will be reconciled to actual sales by September 1 of each Plan year.

month period from June 1 through May 31 (i.e., the PJM year). The Company has until September 1 to true-up its AEPS compliance obligations (based on actual retail sales during each Plan year). According to the definition in Section 75.1, the *true-up period* is the period each year from the end of the reporting year until September 1.

63. Currently, UGI Electric conducts its AEPS RFP in May, just before the annual AEPS compliance window ends, with the contract running June through May. In an effort to improve supplier participation, and, by extension, competition and pricing, UGI Electric is proposing to move the AEPS RFP from May to coincide with the first auction of each year, occurring in January through March. By conducting the auction earlier and in alignment with the energy auction, UGI Electric will move to a period where less competition for AECs is occurring; therefore, greater AEC supplies may be available and in turn, potentially cheaper. Further, this will improve the overall auction process efficiency, holding two auctions at the same time. Doing so will help to reduce auction costs and may result in a greater number of wholesale suppliers participating in the AEC auctions. This proposal is discussed in greater detail in Mr. Rouland's testimony, UGI Electric Statement No. 2.

64. UGI Electric is also proposing to adjust its calculations for determining the number of AECs it must procure by increasing the forecasted number of AECs required to cover the block purchases, the FPFR scheduled versus settlement obligation, NYPA supply, Tier I Adjustment, and GSR-2. The adjusted process will first forecast the anticipated usage for these four areas (kWh), and the resulting AEC obligations will increase the result by 15%.

65. Because UGI Electric is forced to forecast its AEC needs for these areas, there is a risk of under-forecasting and, therefore, under-procurement of the AECs needed for state compliance. By calculating the forecast, and then increasing the resulting need by 15%, the Company is expecting to slightly over-procure the AECs needed in any individual auction. These excess AECs can then be rolled into the next year, reducing the AECs needed in that year. To make this possible, UGI Electric is also proposing to include vintage requirements in its procurement plan for AECs.

66. After the true-up period expires, in the unlikely scenario that the Company is still unable to meet its AEPS credit targets in Section 52 Pa. Code § 75.61, the Company would pay the applicable alternative compliance payment(s) specified in 52 Pa. Code § 75.65(b). In such an instance, the Company requests approval to recover these costs through its default service rates. This is the same methodology that the Company utilized in DSP IV.

67. In accordance with 52 Pa. Code § 75.67, UGI Electric will recover the costs associated with the procurement of AEPS credits (during DSP V) from its default service customers through a Section 1307 automatic adjustment clause rate design as was done in DSP IV.

G. TECHNICAL BID REQUIREMENTS

68. In accordance with 52 Pa. Code § 54.185(e)(2), UGI Electric's DSP V includes technical requirements associated with competitive bid solicitations (consistent with 52 Pa. Code § 54.186).

69. The RFPs noted above will be issued to wholesale suppliers that either have Edison Electric Institute ("EEI") agreements in place with UGI Electric or express interest in participating in the bid rounds (as was done in DSP III and DSP IV).

70. In DSP IV, the Company used an independent market monitor that managed the Company's default service bidding process. In DSP V, UGI Electric plans to issue an RFP seeking an auction manager to provide greater service and support to the Company. The auction manager role is described in the testimony of UGI Electric witness Jesse R. Tyahla, UGI Electric Statement No. 1. UGI Electric requests that the Commission approve the Company's use of an auction manager to be secured through an RFP process occurring prior to the commencement of DSP V.

71. For DSP V, the auction manager will conduct the RFPs in the same manner as was done in DSP IV. The auction manager and UGI Electric will advertise notice of the RFPs in industry publications, and post the RFPs on the Company's Energy Management website, as well as questions (with answers) raised by potential suppliers. The website will include the hourly loads of GSR-1 Group customers from October 1, 2010 through the last full month prior to the issuance of the RFP, as well as hourly temperatures for the same period so that potential bidders can calculate anticipated weather normalized hourly loads. The Company also will conduct a conference call open to all potential suppliers where questions about the RFPs can be addressed. The auction manager will be an active participant throughout this process. Potential suppliers are required to submit bids within three to four weeks of the RFP issuance date. The results of the RFP selection process are subject to final Commission approval.

72. In addition, UGI Electric's affiliate, UGI Energy Services, LLC ("UGI Energy Services") should be permitted to participate in the RFPs for DSP V. Neither UGI Electric nor UGI Energy Services has withheld from the market any generation supply in a manner that violates federal law. As such, UGI Electric's affiliate may participate in the

bids and will not be granted any preference or gain preferential access to any non-public information. Accordingly, UGI Electric requests that the Commission approve potential affiliated interest transactions associated with DSP V pursuant to Section 2102 of the Public Utility Code. The RFP process will also be overseen by the auction manager, and the results will be subject to final Commission approval.

73. As was done in DSP III and DSP IV, the load-following RFPs for DSP V will seek a fixed bid price for each tranche. In a departure from the process used in DSP III and DSP IV, the block RFPs will seek a single price for all 24-months of each of the two blocks that will be offered. The blocks will also have a fixed quantity of supply for all 24-months within the block. The RFPs will include a cover letter, a summary with bid instructions, and a bid form to be completed by interested wholesale suppliers. The instructions will refer interested suppliers to the Company's Energy Management website where they can find relevant documents, including, but not limited to, a copy of the EEI form agreement, historical hourly loads and temperatures, number of customers, a sample confirmation agreement and other relevant information. The RFP instructions in DSP V will continue to explain that bidders must provide documentation demonstrating their good standing and compliance with PJM's tariff, operating agreement, reliability agreement, and business practices. These documents are included as exhibits to Mr. Rouland's testimony.

74. The Company is also proposing to include both Bid Assurance and Performance Assurance Collateral as part of DSP V. Both forms of collateral will provide risk protections to UGI Electric and in turn customers, limiting the exposure and additional costs to procure energy supply in the event a supplier fails to execute an agreement or defaults on a contract after execution. In DSP V, UGI Electric proposes to implement a

fixed fee Bid Assurance Collateral amount of $75,000 per tranche for both FPFR and ATC block products. This amount would aid in covering the costs for an additional auction to reacquire supply following a bidder's failure to execute a contract and could also provide some protection should prices have increased. Further, the Company proposes to implement a fixed fee Performance Assurance Collateral amount of $175,000 for FPFR contracts and $100,000 for ATC block contracts. Similar to Bid Assurance Collateral, Performance Assurance Collateral will aid in covering the cost to hold an auction to reacquire supply after a supplier default and provide a buffer should energy prices increase.

75. The Company will provide the load-following and block bid results to the Commission within one business day after the bid responses become due. Thereafter, the Commission will have one business day to review the bid responses and approve or disapprove the Company accepting the winning responses. If the Commission approves of the winning bid responses, the Company will execute transaction confirmations with the winning suppliers. During the course of DSP V, the Company may work to further improve, or shorten, the time between when bid responses are due and when bid awards are approved and confirmed.

H. CONTINGENCY PLAN

76. In accordance with 52 Pa. Code § 54.185(e)(5), the Company's DSP IV incorporates contingency plans in the event that the Company cannot secure wholesale generation supplies required to meet the default service obligation. The contingency plan for DSP V is a pre-described approach on how the Company will proceed based upon the time-gap between product failure and tariff issuance. In most instances, UGI Electric will first re-auction the failed product unmodified. The re-auction will occur approximately one month after the original auction date (i.e., February or August), including renewed outreach

to suppliers to solicit interest, bidder qualification (for any new bidders) and a rebid of the product. Should the re-auction fail, the Company will modify the product(s) before rebid. In the second layer of the contingency plan, depending upon which product failed, the Company will reduce the 12-month FPFR product to a 6-month FPFR and/or reduce the 24-month ATC block to a 6-month ATC block, and then re-auction the modified product(s). The re-auction of the modified product will occur approximately one month later (e.g., March or September) and again include supplier outreach and qualification. Should this modified product auction fail, the final solution for the FPFR and block products is for the Company to fill the supply using the spot market.

77. In addition, the Company is adding a contingency plan applicable to its AEPs auctions. During DSP V, if UGI Electric experiences a failed auction for any of the three tiers of AECs being solicited, the Company will contact AEC Brokers and Aggregators (Brokers), as identified on the Commission's AEPS website, to determine if any Brokers have the necessary AECs, including the vintages required. If the AECs are potentially available in the market, UGI Electric will solicit bids from at least three different Brokers. Brokers will provide a fixed price for all AECs of the specified vintages. The lowest price offering will be selected.

78. These changes will significantly improve the Company's contingency plan process by establishing a clear plan of action and leveraging AEC suppliers already in the market and recognized by the PUC on their website. By soliciting bids from at least three different Brokers, UGI Electric is conducting a competitive process, continuing to solicit for the AECs needed and acquiring them at the least cost. The contingency plan also provides valuable market feedback. If Brokers also explain that a certain type of AECs are

unavailable in the market, UGI Electric can communicate this to the PUC and better inform next steps that will be taken in compliance with AEPS obligations.

I. COMPLIANCE WITH RTO LEGAL AND TECHNICAL REQUIREMENTS

79. In accordance with 52 Pa. Code § 54.185(e)(4), DSPs must include documentation that the plan is consistent with the requirements pertaining to the generation, sale and transmission of electricity of the RTO in the default service provider's territory (i.e., PJM). For DSP V, the Company is continuing its EEI Master Service Agreement and RFP instructions to require that bidders provide documentation demonstrating their good standing and compliance with PJM's tariff, operating agreement, reliability agreement, and business practices.

80. The Company's RFP instructions also require specific bidder certifications demonstrating they are: 1) qualified market buyers and sellers of electricity in good standing with PJM; 2) positioned to obtain and deliver electric generation supplies in PJM; 3) compliant with all applicable PJM requirements; and 4) authorized by the Federal Energy Regulatory Commission ("FERC") to sell and procure energy, capacity and ancillary services at market-based rates.

J. RATE DESIGN PLAN

81. In accordance with 52 Pa. Code § 54.185(e)(3), UGI Electric's DSP V utilizes a default service rate design plan that recovers all reasonable costs for providing default service. DSP V's rate design plan is similar to the one used in DSP IV. The rate design for DSP V appears in Appendix A to this Petition, which is an updated copy of *Rider B - Generation Supply Service Surcharge* ("Rider B") to the Company's Electric

Service Tariff. Rider B sets forth the schedule of default service rates, rules and conditions for recovering default service costs. [12]

82. The default service rate design plan for DSP V is similar to the rate design plan adopted in DSP IV in that it recovers default service costs on a full and current basis through a Section 1307 reconcilable adjustment clause (including costs for complying with the AEPS Act). Currently, the Company calculates rate changes on a quarterly basis. UGI Electric is proposing to change to semi-annual rate changes. During DSP V, the rates will become effective June 1 and December 1 to align with the June 1 start of the DSP V Plan.

83. The Company's DSP V will include a default service rate design that recovers costs associated with the preparation and provision of DSP V, as well as the default supply costs purchased pursuant to it for the GSR-1 and GSR-2 groupings, including AEPS credits and any required power purchases pursuant to net metering requirements. The reflection of these costs in rates is fully described in the testimony of UGI Electric witness Tracy A. Hazenstab, UGI Electric Statement No. 3.

K. AGREEMENTS AND FORMS USED TO PROCURE ELECTRIC SUPPLY FOR DSP V

84. In accordance with 52 Pa. Code § 54.185(e)(6), the Company is providing copies of its agreements and forms used in the procurement of electric supply for default service customers. These documents include the Company's master supply agreement (i.e., EEI Agreement), RFP documents, and credit and confidentiality agreements. These documents are included as exhibits to Mr. Rouland's testimony.

[12] Appendix A also contains a copy of Rule 5.6(b) of the Company's Electric Generation Supplier Coordination Tariff (regarding monthly charges for the Standard Offer program and how they are to be allocated to suppliers on a per capita basis).

85. UGI Electric plans to acquire default service supplies for DSP V through an EEI Agreement that is similar to the form used in DSP IV. UGI Electric will use the revised EEI agreement and RFP instructions for its load-following and block purchases in DSP V.

L. GENERATION CONTRACTS GREATER THAN 2 YEARS

86. In accordance with 52 Pa. Code § 54.185(e)(7), the Company is identifying generation contracts of greater than 2 years in effect that will be used to provide default service. The only contract that UGI Electric plans to use during the term of DSP V with a term that is greater than 2 years is the Allegheny Agreement. A copy of the agreement is included as an exhibit to Mr. Rouland's testimony. The Company made procurements under this long-term agreement in DSP III and DSP IV and plans to continue these purchases in DSP V. This contract is fully described above in Section III.C.3, *supra*, and in the testimony of UGI Electric witness James M. Rouland, UGI Electric Statement No. 2.

M. RETAIL ENHANCEMENT PROGRAMS FOR DSP V

87. Consistent with DSP IV, DSP V will include two retail enhancement programs: 1) the New/Moving Customer Referral Program; and 2) the Standard Offer Customer Referral Program. The Company is not proposing any modifications to these programs as part of DSP V.

IV. LEGAL STANDARDS

A. THE COMPANY'S PROCUREMENT PLANS MEET ACT 129'S LEGAL STANDARDS

88. The procurement methodologies under DSP V meet the requirements of Act 129 that a procurement plan shall be designed to be "the least cost to consumers over time" and shall include a "prudent mix" of contracts. The hourly price service for GSR-2 Group

customers, and the competitive solicitations for block purchases and full requirements contracts serving GSR-1 Group customers, represent a "prudent mix" of procurement contracts for UGI Electric's default service customers and will provide default service customers with access to an adequate and reliable supply of generation at least cost over time. *See* 66 Pa. C.S. § 2807(e).

89. Specifically, Act 129 requires that power "shall be procured through competitive procurement processes" including auctions, requests for proposals and/or competitively procured bilateral agreements procured at no greater than the cost of obtaining generation under comparable terms in the wholesale market, and such procurement must be a "prudent mix" of spot market purchases, short-term contracts and long-term purchase contracts. *Id.* § 2807(e)(3.1)-(3.2).

90. UGI Electric's DSP V procurement plan is similar to the procurement plans of other EDCs in Pennsylvania and complies with the legal requirements of a "prudent mix" of contracts "designed to ensure adequate and reliable service at the least cost to customers over time. DSP V also meets the procurement requirements of Act 129 by utilizing competitive procurement processes. Further, the Company's DSP V is consistent with the Commission's RMI Orders at Docket No. I-2011-2237952 and, as required by 66 Pa. C.S. § 2807(e)(7), ensures that "the costs of providing service to each customer class are not subsidized by any other class."

91. The procurement process is explained in detail in the direct testimony of UGI Electric witness Mr. Rouland, UGI Electric Statement. No. 2 (Appendix C).

92. For all of the reasons set forth above, this default service plan meets the standards set forth in Act 129 and enables the Commission to make the necessary findings per Section 2807(e)(3.7) as follows:

- UGI Electric's Plan includes prudent steps necessary to negotiate favorable generation supply contracts;
- UGI Electric's Plan includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis; and
- Neither UGI Electric nor its affiliated interests have withheld from the market any generation supply in a manner that violates federal law.

B. WAIVERS

93. UGI Electric recognizes the Commission's default service regulations and policy statement intend that DSPs be tailored to acquire default supplies for specific customer groupings with maximum registered peak loads of: 1) less than 25 kW for residential and non-residential customers; 2) between 25 kW and 500 kW for non-residential customers; and 3) greater than 500 kW for certain non-residential customers (i.e., commercial and industrial customers). 52 Pa. Code §§ 54.187(i)-(k) and 69.1805.

94. However, the regulations and policy statement also provide that DSPs may propose alternative divisions of customers.

95. As noted above, UGI Electric proposes in this Petition to continue to acquire default service supplies for two groups – all customers with supply peak load impacts less than 100 kW, and customers with supply peak load impacts of 100 kW or greater, and, to the extent necessary, requests a waiver from the customer groupings recommended in 52 Pa. Code §§ 54.187 and 69.1805 to permit this procurement strategy to continue.

96. As also noted above, UGI Electric is proposing semi-annual rate changes for GSR-1 customers. Section 54.187(i) of the Commission's regulations provides that

default service rates for customers with a maximum registered peak load of 25 kW to 500 kW should be adjusted on a quarterly basis or more frequently. 52 Pa. Code § 54.187(i). UGI Electric requests a waiver of this regulation to allow semi-annual rate changes for customers from 25kW to 100 kW.

97. These waivers are appropriate given the small size of default service loads on UGI Electric's system.

98. The Commission's default service regulations provide that a DSP shall provide 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 has been approved by the Commission. 52 Pa. Code § 54.188(e)(2). The Company's tariff currently provides for a 30-day notice, and the Company requests that it be able to continue to provide 30 days' notice in advance of PTC changes.

99. The Company also requests any additional waivers needed to implement its DSP V Plan as set forth in this filing.

C. THE PROPOSED RETAIL PROGRAMS ARE IN THE PUBLIC INTEREST

100. The Commission has encouraged EDCs to offer retail market programs, including new and moving customer referral programs and Standard Offer programs to residential and small commercial and industrial customers. *See, e.g.* March 2, 2012 RMI Order.

101. UGI Electric proposes to continue to offer the New/Moving Customer Referral program to its customers during the term of DSP V.

102. Likewise, UGI Electric stands ready to offer a Standard Offer program to refer customers to EGSs should an EGS(s) decide to participate in the Company's Standard Offer program during the term of DSP V.

103. These customer referral programs are in the public interest because they support retail choice.

V. CUSTOMER NOTICE

104. UGI Electric will publish notices containing similar information in the major newspapers serving its service territory. Finally, all notices will refer to UGI Electric's website, (http:// www.ugi.com/rate-filing), where a copy of the entire filing will be maintained.

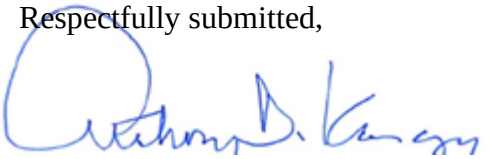
105. UGI Electric is also notifying proposed customer-generators whose facilities would be affected by the GSR-2 classification in this Petition. The Company has no current net metering customers that would be impacted by the proposal.

106. In addition to the above notices, UGI Electric also is serving copies of this filing on the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, the Office of Small Business Advocate, all EGSs registered in UGI Electric's service territory and PJM.

VI. CONCLUSION

WHEREFORE, UGI Electric respectfully requests that the Commission, no later than January 2025: (1) approve the default service program set forth in this Petition; (2) grant affiliated interest approval for transactions with a UGI Electric affiliate in the event such an affiliate submits a winning bid under the default service program's proposed RFP processes; (3) grant any waivers required to implement the default service program set forth in this Petition, including a waiver of the Commission's regulation at 52 Pa. Code § 54.187 to allow UGI Electric to acquire and manage default supplies for the GSR-1 and GSR-2 customer groups as defined herein; (4) authorize UGI Electric to file tariff sheets substantially in the form of the *pro forma* tariff sheets set forth in Appendix A to this Petition on or before May 2, 2025 to be effective June 1, 2025; (5) authorize UGI Electric to file tariff sheets no later than thirty (30) days in advance of June 1 and December 1, beginning June 1, 2025 specifying the applicable GSR-1 Group default service rates; (6) re-approve UGI Electric's retail choice market enhancement programs and grant, to the extent required, any affiliated interest approvals necessary for UGI Electric affiliates to participate in such programs; (7) approve UGI Electric's use of an auction manager that will be secured through an RFP process as its independent third party evaluator; and (8) grant such other relief as the Commission deems appropriate.

Respectfully submitted,



Lindsay Berkstresser (ID # 318370)
UGI Corporation
500 North Gulph Road
King of Prussia, PA 19406
Phone: 717-504-9925
E-mail: berkstresserl@ugicorp.com

Anthony D. Kanagy (ID # 85522)
Nicholas A. Stobbe (ID # 329583)
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101-1601
Tel: 717-731-1970
E-mail: akanagy@postschell.com
nstobbe@postschell.com

Devin T. Ryan (ID # 316602)
Post & Schell, P.C.
One Oxford Centre
301 Grant Street, Suite 3010
Pittsburgh, PA 15219
Tel: 717-612-6052
E-mail: dryan@postschell.com

Date: May 31, 2024

Attorneys for UGI Utilities, Inc. – Electric Division

DocuSign Envelope ID: 8AEEAD6E-6177-411D-B831-B35206E29081

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division For Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029	:	Docket Nos. P-2024-G-2024-

---

VERIFICATION

I, Paul J. Szykman, being the Chief Regulatory Officer for UGI Utilities, Inc. – Electric Division, hereby state the facts set forth in the foregoing petition are true and correct to the best of my knowledge information and belief, and that if asked orally at a hearing in this matter, my answers would be the same as set forth herein. 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: 5/30/2024

DocuSigned by:
0D42C0CB3822401...
Paul J. Szykman

APPENDIX A

ProForma Tariff Supplement
to UGI Electric Pa. P.U.C. No. 6

UGI UTILITIES, INC. – ELECTRIC DIVISION

ELECTRIC SERVICE TARIFF

RULES AND RATES
FOR ELECTRIC DISTRIBUTION SERVICE AND
CHOICE AGGREGATION SERVICE

in the following service territory:

LUZERNE COUNTY

City of Nanticoke, and Boroughs of Courtdale, Dallas, Edwardsville, Forty-Fort, Harvey's Lake, Kingston, Larksville, Luzerne, New Columbus, Plymouth, Pringle, Shickshinny, Sugar Notch, Swoyersville, Warrior Run, West Wyoming and Wyoming.

First Class Townships of Hanover and Newport, and Second Class Townships, of Conyngham, Dallas, Fairmount, Franklin, Hunlock, Huntington, Jackson, Kingston, Lake, Lehman, Plymouth, Ross and Union.

WYOMING COUNTY

Townships of Monroe and Noxen

Issued: Effective for Service Rendered on and after:

Issued by:
Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

THIS TARIFF MAKES CHANGES TO THE EXISTING RATES (PAGE 2).

LIST OF CHANGES MADE BY THIS SUPPLEMENT

(Page Numbers Refer to Official Tariff)

Pursuant to the Final Order entered _____ approving the Default Service Program at Docket No. _____, the following changes have been made to incorporate default service rules beginning June 1, 2025 along with calculated default generation supply service rates effective June 1, 2025:

Rules and Regulations – 17. Net Metering, Pages 30 – 32

- 17-a(3) – Removed rate schedule names for customer types.
- 17-a(4) – Removed outdated language requiring that customer-generators have independent load.
- 17-c(1) – Added language to clarify the Price to Compare that will be used to calculate compensation owed to customer-generators and the timeframe used to define the calculation cycle. Also, added language to define the calculation for compensation to customer-generators served under GSR-2.
- 17-e & 17-f – Removed rate schedule names.
- 17-g – Added language to define the payment distribution timeline.

Rider B – Generation Supply Service Surcharge, Pages 39-41

- Dates have been revised to reflect the Default Service rules beginning June 1, 2025.
- Revised GSR assignment to be based on supply peak load impact and added definition of supply peak load impact.
- Revised timeframe of GSR classification to be determined annually.
- Revised rate calculation frequency from quarterly to semi-annually.
- Added interim filing language for GSR-1.
- Revised GSR-1 formula to include “F” – relative cost factor and added the definition.
- Deleted references to transmission revenue from the EC calculation definition and GSR-2 costs.
- Updated ECA, SEC, Sint language to align with proposed rate updates.
- Added Non-Residential GSR-1 Rate.
- Eliminated migration rider and reverse migration rider from GSR-1 and GSR-2 customers.
- Added formula to show calculation of GSR-2 rate.
- Clarified definition of Price to Compare for GSR-1 customers. Added language to define Price to Compare for GSR-2 customers.
- Clarified information to be provided in annual reconciliation statement.

RULES AND REGULATIONS (continued)

17. NET METERING

17-a Applicability. This rule sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

(1) Customer-generators served under Rate Schedules R, GS-1, GS-4, GS-5, and LP who install a device or devices which are, in the Company's judgment, subject to Commission review a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system are eligible for net metering.

(2) This rule is available to installations where any portion of the electricity generated by the renewable energy generating system offsets part or all of the customer-generator's requirements for electricity.

(3) A renewable customer-generator, under this rule, is a non-utility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service ~~(Rate R)~~ or not larger than 3,000 kilowatts at other customer service locations ~~(Rate GS-1, GS-4, GS-5, and LP)~~, except for a Customer whose system is above 3 megawatts and up to 5 megawatts who may qualify its alternative energy system for customer-generator status if, as set forth in the Commission's regulations: (a) the Customer makes its system available to operate in parallel with the grid during grid emergencies; or (b) the Customer's system is located within a microgrid. **(C)** **(C)**

(4) ~~To qualify for net metering, the customer-generator must, among other things, have electric load, independent of the alternative energy system, behind the meter and point of interconnection of the alternative energy system. To be independent of the alternative energy system, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system.~~ **(C)**

(5) Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. The net metering rules are not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

(6) Service is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

(7) Review and approval of all customer-generator applications and interconnections shall be in accordance with the Commission's regulations.

17-b Metering Provisions. A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. If the Customer agrees, a dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

(C) Indicates Change

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

(3) Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternate energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for the disposition of those credits.

(4) Virtual meter aggregation on properties owned or leased and operated by the same customer-generator shall be allowed for purposes of net metering. Virtual meter aggregation shall be limited to meters located on properties owned or leased and operated by the same customer-generator within two (2) miles of the boundaries of the customer-generator's property and within the Company's service territory. All service locations to be aggregated must be Company service location accounts held by the same individual or legal entity receiving retail electric service from the Company and have measurable load independent of any alternative energy system. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing their account on a virtual meter aggregation basis.

17-c Billing Provisions. The following billing provisions apply to customer-generators in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at full retail rate, consistent with Commission regulations. If a customer-generator supplies more electricity to the electric distribution system than the Company delivers 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-generator in subsequent billing periods shall continue to accumulate until the ~~end of the year.~~final billing period on or before the end of the PJM year (May of each year). At the end of each PJM year, the Company will 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 ~~Company's~~ Customer's applicable Price to Compare (PTC-1 or PTC-2). Applicable PTC-2 rates shall be applied to the respective hours of excess generation. ~~(PTC-1) rate for customers receiving default service on GSR-1.~~ The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule. **(C)** **(C)** **(C)** **(C)**

(C) Indicates Change

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

(3) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs must be stated in the service agreement between the customer-generator and the EGS. The Company shall credit customer-generators who are EGS customers for each kilowatt-hour of electricity produced at the Company's unbundled distribution kilowatt-hour rate. The distribution kilowatt-hour rate credit shall be applied monthly against kilowatt-hour distribution usage. If the customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in any billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's unbundled kilowatt-hour distribution usage in subsequent billing periods until the end of the year when all remaining unused kilowatt-hour distribution credits shall be zeroed-out. Distribution credits are not carried forward into the next year.

(4) 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. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by the same customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

17-d Application. Customer-generators seeking to receive service under the provisions of this rule must submit a written application to the Company demonstrating compliance with the net metering provisions and quantifying the total rated generating capacity of the customer-generator facility.

17-e Minimum Charge. The Minimum Charges under ~~Rate Schedule R, GS-1, GS-4, GS-5, and LP~~the applicable rate schedule apply for installations under the net metering rules. **(C)**

17-f Applicable Charges and Fees. Bills rendered by the Company under this rule shall be subject to charges and fees applicable to ~~Rate Schedules R, GS-1, GS-4, GS-5, and LP.~~the assigned rate schedule. **(C)**

17-g Payment distribution. Any remaining credit balance as of the end of the May billing period will be paid to the customer via check within 90 days of May 31. **(C)**

(C) Indicates Change

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE

Company will supply Default Generation Supply Service (GSS) to Customers in the Company's service territory not receiving service from an EGS. The rules and rates contained herein apply to service provided on and after June 1, ~~2021~~2025. **(C)**

For Customers served through the Company's GSS, a Generation Supply Rate (GSR) shall be applied to each kilowatt hour of energy used by the Customer. Separate GSRs shall be calculated ~~and apply to the rate schedules listed below~~and apply in accordance with the following:~~.~~ **(C)** **(C)**

GSR-1 shall apply to all residential customers as well as non-residential customers with a supply peak load impact less than 100 kW. **(C)**

GSR-2 shall apply to all non-residential customers with a supply peak load impact greater than or equal to 100 kW. **(C)**
~~GSR-1 shall apply to Rate Schedules R, GS-1, GS-5, FCP, BLR, OL, SOL, MHOL, LED-OL, SL, SSL, MHSL, LED-SL and LED-CO.~~
~~GSR-1 shall also apply to Rate Schedules GS-4 and LP where the Customer's annual peak load is less than 100 kW.~~
~~GSR-2 shall apply to Rate Schedules GS-4, LP, and HTP where the Customer's annual peak load is greater than or equal to 100 kW.~~

Supply peak load impact will be determined on 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. **(C)**

The supply peak load impact used to assign customers to the applicable GSR rate shall be the Customer's highest supply peak load impact (kW) in the most recent 12-month period ending September 30. ~~Customer's highest billing demand in the twelve-month period ending September 30, 2020 shall be the annual peak load determinant for purposes of applying the GSR.~~ For new Customers without a twelve-month billing history, the ~~billing demand~~ supply peak load impact shall be based on the Company's estimate using factors such as, but not limited to, similarly equipped buildings, 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. **(C)** **(C)**

The GSR-1 rate shall be calculated every ~~three~~ six months beginning June 1, ~~2021~~2025. The GSR-1 rate shall be filed with the Commission with at least thirty days' notice prior to each ~~three~~six-month period and shall be posted on the Company's website. If the GSR-1 calculation results in a change in rate that is less than 2%, the Company, in its sole discretion, may file with the Commission a GSR-1 rate that is unchanged from the prior period. Pursuant to 52 Pa. Code § 69.1809(c), the Company may propose an interim reconciliation prior to the next adjustment interval. The rate will be calculated as follows: **(C)** **(C)**

$$GSR\text{-}1 = (((EC*F)/SEC) + (ECA/SECA) + (Int/Sint)) * (1/(1-T)) \quad \textbf{(C)}$$

EC = Projected direct and indirect purchased power costs incurred by the Company to acquire electric supply for the GSR-1 group for the next ~~three-month~~computation period including, a load following service, wholesale energy costs, alternative energy credits, capacity costs, transmission costs, and all other PJM bill line item expenses/credits excluding network transmission service credits and firm point-to-point transmission service credits/expenses. EC also includes administrative costs, legal costs, taxes, net metering costs related to required excess power purchases at the PTC-1 rate, and any other applicable costs of providing default service for the GSR-1 group. ~~The estimated EC shall be reduced by the estimated transmission revenues to be collected in accordance with the applicable rate schedules included in the GSR-1 group.~~ **(C)** **(C)** **(C)**

(C) Indicates Change

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE (continued)

F = Relative Cost Factor, updated at the beginning of the plan period on June 1, 2025. However, should the supply load change by more than 50% during the course of the application period, the Company will update the relative cost factors. The Relative Cost Factor reflects the load shape of the residential and non-residential classes and is: **(C)**

Application Period	Residential	Non-Residential
June 1, 2025 – May 31, 2029	1.02	0.93

ECA = Net over or under collection of the EC defined above to be refunded/recovered and calculated across relative cost factors. The ECA will be reconciled ~~quarterly~~ based on actual EC revenues received and actual EC costs incurred for the ~~three~~six-month period ending two months prior to the filed GSR effective date. ~~Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-1 Customers shall be included in the ECA component of the GSR-1 beginning June 1, 2021. The over/under collection existing as of May 31, 2021 shall be allocated to GSR-1 and GSR-2 Customers based on the percentage of the actual sales during the period of the over/under collection attributed to those Customers classified as GSR-1 and GSR-2 as of June 1, 2021.~~ In the event the ECA would result in less than (or equal to) a five percent (5%) change in the average total Residential bill, the Company will refund/recover the balance over a ~~three~~six-month period. In the event the ECA would result in more than a five percent (5%) change in the average total Residential bill for default service, the Company will refund/recover the balance over a ~~six, nine, or~~ twelve-month period ~~(as determined by the Company)~~. **(C)** **(C)** **(C)** **(C)**

Int = 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.

T = The Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates, expressed in decimal form.

SEC = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the next ~~three-month~~computation period, in kilowatt hours. **(C)**

SECA = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the refund/recover period, in kilowatt hours.

Sint = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the ~~twelve-month period beginning December 1~~next computation period, in kilowatt hours. **(C)**

The current GSR-1 rate (in ¢/kWh) is: **(C)**

Residential	Non-Residential
x.xx	x.xx

(C)

~~10.525 ¢/kWh~~

~~GSR-2 shall be calculated for each default service Customer in this group. Company shall bill each Customer on a calendar month based upon actual costs incurred to serve the Customer. The costs will be allocated as follows:~~ **(C)**

~~Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 Customer by multiplying the Customer's actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.~~

~~(~~**(C) Indicates Change**

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE (continued)

GSR-2 shall be calculated for each default service Customer in this group. Company shall bill each Customer on a calendar month based upon actual costs incurred to serve the Customer. The costs will be allocated as follows: **(C)**

GSR-2 = (HEC + HPC + HTC) * (1/(1-T)) **(C)**

HEC = Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 Customer by multiplying the Customer's actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.

HPC = Other power costs incurred by the Company to acquire electric supply for the GSR-2 group for the month shall be allocated to each GSR-2 Customer based on metered sales. Other power costs include alternative energy credits and all PJM bill ~~line item~~line-item expenses/credits excluding the following: costs for capacity services, transmission services, network transmission service credits and firm point-to-point transmission service credits/expenses. Other costs included are administrative costs, net metering costs related to required excess power purchases pursuant to PTC-2, legal costs, taxes, and any other applicable costs of providing default service for the GSR-2 group. ~~The actual costs shall be reduced by the actual transmission revenues to be collected in accordance with the applicable rate schedules included in the GSR-2 group.~~ **(C)**

HTC = Cost for capacity and transmission services based on the PJM bill ~~line item~~line-item expenses/credits applicable to these services shall be allocated to each Customer in the GSR-2 group. The capacity costs shall include the PJM bill line items for locational reliability, capacity transfer rights, RPM auction, and capacity resource deficiency. The capacity costs shall be allocated to each Customer based on each Customer's peak load contribution (PLC). The transmission costs shall include the PJM bill line items for network integration transmission service charges, transmission enhancement service charges/credits, and non-firm point-to-point transmission service charges/credits. The transmission costs shall be allocated to each Customer based on each Customer's network service peak load value (NSPL). Any expense/credit line items added by PJM related to these services shall be allocated based on the Customer's applicable PLC and NSPL. **(C)**

~~Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-2 Customers that migrate from rate GSR-1 shall be refunded/recovered from those Customers directly over 12 billing periods beginning September 1, 2021. The over/under collection existing as of May 31, 2021 shall be allocated to GSR-1 and GSR-2 Customers based on the percentage of the actual sales during the period of the over/under collection attributed to those Customers classified as GSR-1 and GSR-2 as of June 1, 2021. Customers who undergo reverse migration, switching from GSR-2 to GSR-1 during the DSP IV term, will be exempted from any over/under collections as reflected in the Company's E-factor (existing as of May 31, 2021) for a period of 12 months after returning to GSR-1.~~ **(C)**

T = All costs for GSR-2 Customers shall include the Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates. **(C)**

Price to Compare: The Price~~-To-~~ to Compare ("PTC") for GSR-1 (PTC-1) shall include the ~~Energy Charge ("EC"), and the Energy Cost Adjustment ("ECA"), contained in this Tariff. The Price-To-Compare shall also include the~~GSR-1 rate and the State Tax Surcharge in Rider A. Separate PTC-1 rates will apply to residential and non-residential customers. ~~PTC is not applicable to GSR-2.~~The Price to Compare for GSR-2 (PTC-2) shall include the GSR-2 rate and the State Tax Surcharge in Rider A. **(C)**

Annual Reconciliation Statement: On June 30 of each year, the Company will file with the Commission, its Annual Reconciliation Statement for the GSR-1 rate, with the actual costs and revenue for both residential and non-residential customers ~~for~~aggregated, for the preceding 12 months ending May 31. **(C)**

(C) Indicates Change

APPENDIX B

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. –	:	
Electric Division For Approval of	:	Docket Nos. P-2024-
a Default Service Plan (DSP V) for	:	G-2024-
the Period of June 1, 2025 through	:	
May 31, 2029	:	

DIRECT TESTIMONY
OF
TRACY A. HAZENSTAB

UGI ELECTRIC STATEMENT NO. 3

Dated: May 31, 2024

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab, and my business address is UGI Utilities, Inc., 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. as a Principal Analyst, Rates. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric" or "the Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Principal Analyst, Rates?

A. I am primarily responsible for various tariff filings and related computations for UGI Electric and UGI Gas rate and regulatory filings before federal and state regulatory commissions.

Q. Please describe your educational and professional experience.

A. Please see my resume, UGI Electric Exhibit TAH-1, which is attached to my testimony.

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

A. Yes. UGI Electric Exhibit TAH-1 contains a list of the proceedings in which I previously testified.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Electric in support of its proposed Default Service Plan V ("DSP V" or the "Plan"). Specifically, I will address the rate design and Section 1307(e) cost recovery mechanisms that are currently used to recover the costs of UGI Electric's existing DSP IV and that will continue to be used during DSP V for the term of June 1, 2025 through May 31, 2029. My testimony will also address certain tariff updates clarifying the applicability of UGI Electric's Generation Supply Rate ("GSR") and Price-to-Compare ("PTC"), in particular as related to customers receiving default service under UGI Electric's GSR-2 rate (service with supply peak load impact of 100kW and above) and implementing clear guidelines related to its applicability for net metering customer-generators. I will also discuss additional tariff modifications and retail enhancement programs in DSP V.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the exhibits identified as UGI Electric Exhibits TAH-1 and TAH-2.

II. OVERVIEW OF DEFAULT SERVICE RATES

Q. Please describe the current structure of UGI Electric's default service rates.

A. In DSP IV, UGI Electric applies a GSR to customer bills for those customers receiving default service from the Company. The GSR has two rate groups, those being GSR-1 and GSR-2. Customers having a system impact equal to or greater than 100kW are assigned to GSR-2 in accordance with DSP IV provisions.

Q. Is the Company proposing any changes to the structure of its default service rates?

A. Yes, the Company is proposing tariff modifications that will improve the clarity of the tariff language. These changes will assign customers to a GSR rate group (GSR-1 or GSR-2) based on their default supply peak load impact. Those customers with larger ability for peak load impact greater than or equal to 100kW shall be assigned to the GSR-2 rate group. The Company is also expanding its tariff language to better identify the treatment of customer-generators and align its DSP with the operational impact of these entities as discussed in the testimony of UGI Electric witness James M. Rouland, UGI Electric Statement No. 2.

Q. What customers are included in GSR-1?

A. GSR-1 shall apply to all residential customers as well as non-residential customers with a supply peak load impact less than 100 kW.

Q. What customers are included in GSR-2?

A. GSR-2 shall apply to all non-residential customers with a supply peak load impact greater than or equal to 100 kW.

Q. Is the Company proposing any other tariff changes regarding the classification of GSR-1 and GSR-2 customers?

A. Yes. Consistent with the Company's Settlement commitment in DSP IV, the Company evaluated the classification of customers to the applicable GSR rate at the start of the Plan, using the Customer's highest billing demand in the twelve-month period ending September 30, 2020. Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-2 customers that migrated from rate GSR-1 was refunded/recovered from those customers directly over 12 billing periods beginning September 1, 2021. This over/under collection totaled $2,585 and was allocated to GSR-1 and GSR-2 customers based on the percentage of the actual sales during the period of the over/under collection attributed to those customers as of June 1, 2021. Additionally, customers who underwent reverse migration, switching from GSR-2 to GSR-1 during the DSP IV term, were exempted from any over/under collections as reflected in the Company's E-factor (existing as of May 31, 2021) for a period of 12 months after returning to GSR-1.

In DSP V, the Company is proposing to conduct this review annually. Also, the basis for determination shall be the Customer's peak load impact on the Company's default service supply activities. Specifically, where a Customer's

supply peak load impact is greater than or equal to 100kW, GSR-2 will apply. Supply peak load impact will be determined on 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. This approach recognizes that the magnitude of impact on default service supply activities is similar for all large peak load Customers, even in situations where net power from a net metering customer-generator is flowing into the Company's distribution system. Additionally, the Company is proposing to eliminate the migration charges and the reverse migration charges because the determination and movement of customers between applicable GSR-1 or GSR-2 rates will occur on a timely basis. Historically, the migration rider charges transferred to GSR-2 customers have been minimal, even where the Company did not use an annual evaluation process.

Q. What costs are included for GSR-1 rates?

A. The Company's GSR-1 rates include the supply procurement portfolio described in the testimony of Mr. Rouland. The GSR-1 rates include the costs from all deliveries made pursuant to supply contracts and spot market purchases required to serve the Company's GSR-1 customers, PJM-related costs, costs associated with the purchase of renewable energy credits procured in order to meet UGI Electric's requirements under the Alternative Energy Portfolio Standards Act ("AEPS"), net metering payments to customer-generators made at the Price-to-

Compare rate for GSR-1 customers (PTC-1), as well as administrative costs associated with the provision of default service to customers.

Q. What costs are included for GSR-2 rates?

A. The Company's GSR-2 rates will include the supply from the procurement method described in the testimony of Mr. Rouland. GSR-2 customers are served on an hourly basis through purchases made in the spot market at the generation supply prices established by PJM's real-time hourly market. For these procurements, the Company will pass through the costs associated with any necessary PJM-related costs, such as capacity, transmission to UGI Electric's system, ancillary services, congestion management services, AEPS credits, net metering payments made at the PTC rate for GSR-2 customers (PTC-2) customer-generators, administrative costs associated with the provision of default service to customers, and such other services or products as necessary to provide default service supply. PJM will bill UGI Electric for the hourly usage and related costs on a monthly basis.

III. PJM COSTS

Q. What PJM costs does UGI Electric incur in its provision of default service?

A. UGI incurs fees from PJM for capacity, load response, ancillary charges, administrative fees, and non-market-based transmission costs.

Q. How are non-market-based transmission costs for load following service currently accounted for in DSP rates?

A. Currently, the non-market-based transmission costs are included in the GSR-1 rate in two different ways. For supply that is received through the Company's load following contracts, these costs are currently included as part of the total all-in pricing offered by the supplier. For the portion of the Company's portfolio that is made up of block and spot purchases, as well as the entirety of the GSR-2 supply activities, the costs are billed to UGI Electric by PJM monthly and are allocated for inclusion in the calculation of the GSR-1 and GSR-2 rates.

Q. Is the Company proposing any changes to how it will record non-market-based transmission costs?

A. Yes. As described in Mr. Rouland's testimony, the Company is proposing to remove the non-market-based transmission costs from its load following contracts. Therefore, the associated PJM costs will be billed directly to UGI Electric by PJM. These PJM costs related to default supply to GSR-1 customers will be appropriately allocated to GSR-1 for recovery. This proposal should have no impact on the PJM costs included in rates for GSR-2 customers.

IV. AEPS COSTS

Q. How will the costs be established for AEPS credits in DSP V?

A. During DSP V, UGI Electric will procure AEPs credits consistent with the procurement proposal included in the testimony of Mr. Rouland. For GSR-1, that

entails a combination of AEPs credits purchased directly by UGI Electric, as well as credits purchased by the load following suppliers. For GSR-2, UGI Electric will purchase all credits required for compliance. The cost of the credits purchased will be allocated to GSR-1 and GSR-2 customers based on metered sales.

Q. Are there any costs that the Company might incur if it does not meet its AEPS compliance targets?

A. Yes. After the true-up period expires, in the unlikely scenario that the Company is still unable to meet its AEPS credit targets in Section 52 Pa. Code § 75.61, the Company would be required to pay the applicable alternative compliance payment(s) specified in 52 Pa. Code § 75.65(b). The Company proposes to recover all AEPS credit procurement costs, including compliance costs, through its default service rates.

V. ADMINISTRATIVE COSTS

Q. Is UGI Electric proposing to recover administrative costs incurred in procuring Default Service supply?

A. Yes, UGI Electric is proposing to recover Administrative and General ("A&G") expenses associated with the provision of default service for the GSR-1 and GSR-2 customer groupings. This treatment of A&G expenses is consistent with the Company's historic practice.

Q. What costs are included in UGI Electric's A&G expense category in the DSP?

A. The A&G costs included in the GSR rates cover the following activities: auction management; load forecasting; development of the DSP V procurement plan, internal company costs, legal costs, metering, and billing. The categories of costs included in the DSP V are similar in nature to those included during the Company's DSP IV plan, with some further expansion as discussed in Mr. Tyahla's testimony. All applicable administrative costs are identified in UGI Electric Exhibit TAH-2 with forecasted values. Actual costs will be allocated to GSR-1 and GSR-2 as outlined in the exhibit. As identified in UGI Electric Exhibit TAH-2, certain of these costs will be included in GSR-1 and GSR-2 on a reconcilable basis and certain will be fixed or non-reconcilable costs.

Q. What is the anticipated total impact of the administrative costs UGI Electric proposes to include in its DSP V, on an annual basis?

A. On an annual basis, the administrative costs will average $557,891, inclusive of Gross Receipts Tax. Approximately $425,528 of these costs will be allocated to GSR-1, with the remaining $132,363 allocated to GSR-2. Estimated administrative costs allocated to GSR-1 and GSR-2 in DSP IV totaled $203,745 and $70,039, respectively. The increase is attributed to increased legal expense to more closely align with anticipated legal expense to be incurred during DSP V, the inclusion of a procurement plan consultant, the addition of an auction manager in DSP V, and increased labor costs.

Q. For A&G expenses that are amortized, is the Company proposing any changes to its current amortization practices?

A. Yes. In DSP IV, any invoices that were amortized are being amortized through the months that are remaining in the DSP IV plan, regardless of the size of the invoice. In DSP V, the Company is proposing to only amortize those invoices that are above a threshold of $5,000. The $5,000 threshold is consistent with business practices used in other areas of the Company. Placing a limit on the size of invoices that are amortized will streamline business practices and have no impact to customers' rates.

VI. RECOVERY OF COSTS

Q. How does the Company plan to recover the default service costs through its tariff?

A. The rate design plan for DSP V recovers these costs on a full and current basis through a Section 1307 reconcilable adjustment clause (including costs for complying with the AEPS Act). The Company's DSP V will include a rate design that recovers costs associated with procurements for the GSR-1 and GSR-2 groupings, including AEPS credits.

Q. Is the Company proposing any modifications to its current rate calculation methodology?

A. Yes. As discussed in the testimony of Mr. Tyahla, and consistent with the Settlement of DSP IV,[1] the Company hired NorthBridge Group to conduct a procurement study. The study recommended the Company utilize relative cost factors to calculate separate default service rates for residential and non-residential customers, which would apply specifically to the Energy Cost (EC) component. The Company proposed to implement these allocation factors in DSP V as part of the Settlement of DSP IV. As the procurement study recommended that the Company could utilize the same allocation factors for a multi-year period, the Company is proposing to utilize the factors calculated in the study for the duration of DSP V. In order to calculate the residential default service rate, the EC component will be multiplied by 1.02. A factor of 0.93 would be applied to the EC component to calculate the non-residential rate. The application of these factors would calculate separate EC components for the residential and non-residential customers. Should GSR-1 or GSR-2 supply load change by more than 50% during the course of DSP V, the Company will update the procurement study and utilize the new resulting relative cost factors.

[1] *See Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021 through May 31, 2025*, Docket No. P-2020-3019907 (Order entered Jan. 14, 2021).

Q. Please describe the proposed rate calculation for GSR-1 customers, as modified by the allocation factor.

A. The GSR-1 tariff rate appears in UGI Electric Appendix A (a copy of the Company's updated pro forma tariff pages for Rider B – Generation Supply Service) and will be calculated according to the following formula:

GSR-1 = (((EC*F)/SEC) + (ECA/SECA) + (Int/Sint)) * (1/(1-T))

Where:

- Energy Costs (EC) – Projected direct and indirect purchase power costs (for load following procurements) in the upcoming computation period, including all PJM bill line items, administrative costs, AEPS credits, net metering costs related to required excess power purchases pursuant to PTC-1, etc. The EC will be multiplied by the appropriate Relative Cost Factors (F) and divided by Sales for the Projected Period (SEC). The SEC includes projected sales for all default service customers in GSR-1 for the upcoming computation period.

- Energy Cost Adjustment (ECA) – The ECA (i.e., E-Factor) is the net over or under collection related to the EC, which is collected/refunded for the computation period based on EC revenues received and actual EC costs incurred for the six-month period ending 2 months before the GSR effective date. The ECA is divided by the Sales Used to Calculate the ECA (SECA). The SECA includes projected sales for all default service customers in GSR-1 for the adjustment period. If the ECA would result in less than (or equal to) five percent (5%) change in the average total Residential bill, the Company will calculate the ECA over six-months of sales. If the ECA would result in more than a 5% change in the system average total Residential bill for default service, UGI will refund/recover the balance over twelve months of sales.

- Interest (Int) – Interest associated with over and under collections. The interest is computed at the prime rate for commercial banking, not to exceed the legal rate of interest as reported in the Wall Street Journal. The Int is divided by the Sales Interest (Sint). The Sint includes the projected sales for default service customers in GSR-1 for the computation period.

- Taxes (T) –Taxes (i.e., Pennsylvania Gross Receipts Tax) are applied to the sum of the above-components.

Q. Please describe the proposed rate calculation for GSR-2 customers.

The rate design for costs associated with procurements for the GSR-2 grouping (appears in UGI Electric Appendix A, the updated pro forma tariff pages for Rider B – Generation Supply Service) will be calculated for each default service customer in the group and will be based on actual costs incurred to serve the customer. The GSR-2 rate will be calculated according to the following formula:

$$GSR\text{-}2 = (HEC + HPC + HTC) * (1/(1-T))$$

Where:

- Energy Costs (HEC) incurred by the Company to procure electric supply are multiplied by the customer's LMP for each hour of the billing month.
- Other Power Costs (HPC) incurred in the procurement of electric supply, which are allocated according to metered sales. These costs include AEPS credits, PJM bill line items (excluding costs for capacity services, transmission services, network transmission service credits and firm point-to-point transmission expenses/credits), net metering costs related to required excess power purchases pursuant to PTC-2, legal costs, taxes, and any other applicable costs.
- Costs for Capacity and Transmission (HTC) included on the PJM bill are allocated to GSR-2 customers in two different ways. Capacity costs include locational reliability, capacity transfer rights, RPM auction and capacity resource deficiency costs. These costs are allocated based on each customer's peak load contribution ("PLC"). Transmission costs include network integration service charges, transmission enhancement service charges/credits and non-firm point-to-point transmission service charges/credits. These costs are allocated based on each customer's network service peak load value ("NSPL").
- Taxes (T) – Taxes (i.e., Pennsylvania Gross Receipts Tax) are applied to the sum of the above-components.

Q. How will supply costs be billed for GSR-2 customers?

A. An individual GSR-2 bill shall be calculated for each default service customer in this group based upon actual costs plus allocated administrative costs as described in UGI Electric Exhibit TAH-2. Pro forma tariff pages setting forth the proposed GSR-2 are provided in Appendix A to the Company's Petition.

Q. Is the Company proposing any modification to the frequency of rate changes for the GSR-1 customers?

A. Yes. The Company currently calculates rate changes for GSR-1 customers on a quarterly basis. The Company is proposing to change to semi-annual rate changes. The rates will become effective June 1 and December 1 to align with the June 1 plan start. Tariff filings will be made to the Commission on 30-days' notice. As part of this proposal, and to transition customers to the frequency update, the Company proposes to recover the over/under collection for January 1, 2025 – March 31, 2025, over the six-month period of June 1, 2025 – November 30, 2025. Thereafter, the June 1 rate will capture the actual over/under collection for the period October 1 – March 31 and the December 1 rate will calculate the actual over/under collection for the period April 1 – September 30. Pro forma tariff pages setting forth the proposed GSR-1 are provided in Appendix A to the Company's Petition.

Q. What is the proposed reconciliation period for the GSR-1 rate?

A. On or before June 30th of each year, the Company will file an annual reconciliation statement for the GSR-1 rate for the preceding 12-months ending May 31. The reconciliation statement will contain aggregated costs and revenues for residential and non-residential customers.

VII. PRICE TO COMPARE

Q. How does UGI Electric currently establish the PTC?

A. Currently, pursuant to its tariff as contained within Rider B – Generation Supply Service Surcharge, the GSR-1 customer PTC is calculated at the GSR-1 rate plus the State Tax Adjustment Surcharge. For the purposes of clarity, UGI Electric is adding the designation "PTC-1" to its tariff to align with the GSR-1 designation of the rate.

Q. How does UGI Electric propose to modify the PTC-1 as part of this proceeding?

A. As part of this proceeding, UGI Electric proposes to calculate a separate price to compare for the residential and non-residential customers served under GSR-1. This change is necessary due to the addition of relative cost factors in the GSR-1 rate calculation that will result in separate residential and non-residential GSR-1 rates.

Q. What PTC is currently applicable for GSR-2 customers?

A. For GSR-2 customers, Rider B currently notes that "PTC is not applicable to GSR-2."[2] This is because the PTC for GSR-2 is not an absolute price value, as GSR-2 customers are priced hourly in accordance with the PJM Locational Marginal Price ("PJM LMP"), plus associated allocated costs.

Q. How does UGI Electric propose to clarify the application of a PTC for GSR-2 customers?

A. As part of this proceeding, UGI Electric proposes to clearly identify that an appropriate price to compare for the GSR-2 customers is the applicable hourly PJM LMP (plus associated allocated costs) for the service time period. Thus, UGI Electric is proposing to update the applicable tariff language to clarify that the Price to Compare for GSR-2 customers, the "PTC-2", shall be the GSR-2 rate plus the State Tax Adjustment Surcharge in Rider A.

Q. Do any other Pennsylvania EDCs similarly distinguish the PTC for GSR customers with higher system demand?

A. Yes. In particular, PPL Electric Utilities Corporation's price to compare reflects that customers receiving Real Time Pricing based default service rates also have a PTC based upon Real Time Pricing.[3]

[2] *See* UGI Electric Tariff Pa. P.U.C. No. 6, Supplement No. 52 at Second Revised Page No. 41.
[3] *See* https://www.pplelectric.com/utility/about-us/for-generation-suppliers/general-supplier-reference-information/price-to-compare-and-shopping

Q. How will this tariff update assist customers?

A. The clarifying language proposed by UGI Electric will readily assist GSR-2 customers in transparently understanding the basis for and applicability of the GSR-2 PTC-2.

Q. Please explain how the Company will provide notification of its PTC-1 and PTC-2.

A. Continuing current practice, the PTC-1 will be posted on PAPower Switch and the Company's website and will be provided to the Office of Consumer Advocate 30 days prior to its effective date. Separate price to compare rates will be posted for residential and non-residential customers under PTC-1 and will be included as a message on customer bills. This 30-day notification aligns with the submission of the tariff filings to the Commission and permits sufficient time, should it be needed, for the Company to execute on supply procurement contingency plans. Because this notification timeframe is outside of the window established in 52 Pa. Code § 54.188(e)(2), the Company is requesting a waiver of the Commission's noticing requirements. A formula for the calculation of PTC-2 will be posted on the Company's website and will also be included as a message on customer bills.

Q. Is the Company proposing to update the Net Metering section of the tariff?

A. Consistent with the designation and clarification related to PTC-1 and PTC-2 language above, commensurate updates to the net metering language found in tariff Section 17 have been made. Also, language additions have been made to

clarify the end of the net metering annual period is associated with the end of the billing period falling in May. This recognizes that some net metering customers will not have billing periods that exactly match calendar months. The Company has also clarified the timing of payments related to the purchase of excess generation annually. Finally, the Company has removed outdated language related to the need for independent load at net metering installations.

VIII. RETAIL ENHANCEMENT PROGRAMS FOR DSP V

Q. What retail enhancement programs will the Company continue during DSP V?

A. Consistent with DSP IV, DSP V will continue two retail enhancement programs: (1) the New/Moving Customer Referral Program; and (2) the Standard Offer Customer Referral Program.

Q. What is the New/Moving Customer Referral Program?

A. The Company's New/Moving Customer Referral Program provides customers new to, or moving within, the service territory information about retail choice during service calls to UGI Electric. During these calls, UGI Electric will refer its customers to the Commission's PA Power Switch website. The Company also will explain how the Company's PTC can be used in considering EGS price offers and how the PTC changes over time. Further, the Company will explain the difference between fixed and variable generation supply contract options.

Q. Does the Company currently have any EGSs participating in the Standard Offer Program?

A. While the Company stands ready to support a Standard Offer Program, there are no retail EGSs that are currently participating in UGI Electric's Standard Offer program.

Q. Does this conclude your testimony?

A. Yes.

UGI Electric Exhibit TAH-1

Tracy A. Hazenstab
Principal Analyst - Rates

Work Experience:

2008 - Current	Rates Analyst – II/Sr/Principal (Progressive Positions) UGI Utilities, Inc., Denver, PA
2004 - 2008	Business Analyst PPL Gas, Lewistown, PA
2001 - 2004	Contact Center Analyst PPL Gas, Lock Haven, PA

Previous Testimony – Pennsylvania Public Utility Commission:

2014 1307(f) Proceeding:	Docket No. R-2014-2543523
2015 1307(f) Proceedings:	Docket Nos. R-2015-2480937, R-2015-2480934
2016 1307(f) Proceedings:	Docket Nos. R-2016-2543311, R-2016-2543314
2018 1307(f) Proceedings:	Docket Nos. R-2018-3001631, R-2018-3001632
2019 1307(f) Proceeding:	Docket No. R-2019-3009647
2019 UGI Electric EEC Phase III Petition:	Docket No. R-2019-3004144
2020 1307(f) Proceeding:	Docket No. R-2020-3019680
2021 UGI Gas Base Rate Proceeding:	Docket No. R-2021-3030218
2022 UGI Electric Base Rate Proceeding:	Docket No. R-2022-3037368
2023 1307(f) Proceeding:	Docket No. R-2023-3040290
2024 UGI Gas EEC Phase II Petition:	Docket No. R-2024-3048418

Previous Testimony – Maryland Public Service Commission:

Purchased Gas Adjustment/Annual Cost Adjustment Hearing:

2008 Hearing:	Case Number 9511(c)
2009 Hearing:	Case Number 9511(d)
2010 Hearing:	Case Number 9511(e)
2012 Hearing:	Case Number 9511(g)
2014 Hearing:	Case Number 9511(i)
2015 Hearing:	Case Number 9511(j)
2016 Hearing:	Case Number 9511(k)
2017 Hearing:	Case Number 9511(l)
2018 Hearing:	Case Number 9516(a)
2019 Hearing:	Case Number 9516(b)
2020 Hearing:	Case Number 9516(c)

Assisted in Preparing – Pennsylvania Public Utility Commission:

2009 UGI Gas Rate Case (former Central Rate District):	Docket No. R-2008-2079675
2009 UGI Gas Rate Case (former North Rate District):	Docket No. R-2008-2079660
2011 UGI Gas Rate Case (former Central Rate District):	Docket No. R-2010-2214415
2016 UGI Gas Rate Case (former South Rate District):	Docket No. R-2015-2518438
2017 UGI Gas Rate Case (former North Rate District):	Docket No. R-2016-2580030
2018 UGI Electric Rate Case	Docket No. R-2017-2640058
2019 UGI Gas Rate Case	Docket No. R-2018-3006814
2020 UGI Gas Rate Case	Docket No. R-2019-3015162

Education:

B.A. in International Politics, Pennsylvania State University

UGI Electric Exhibit TAH-2

UGI Utilities, Inc. - Electric Division
Default Service Filing: Effective June 1, 2025 - May 31, 2029
Annual Administrative Expense Allocation

Administrative Expenses Description	Rate Groups		
	GSR-1	GSR-2	Total
Outside Expenses[1]			
Outside Legal Expenses	$ 54,631	$ 7,869	$ 62,500
Consulting Services - Plan Development & Testimony	$ 32,779	$ 4,721	$ 37,500
Auction Manager	$ 131,116	$ 18,884	$ 150,000
Load Forecasting	$ 30,594	$ 4,406	$ 35,000
Company Expenses[2]			
Filing Costs - Salaries	$ 10,818	$ 1,558	$ 12,376
IT Support for Price to Compare and Relative Cost Factor Updates	$ 4,518	$ 651	$ 5,169
Supply Procurement	$ 6,168	$ -	$ 6,168
Load Research Meter Reading	$ 125,680	$ -	$ 125,680
Allocation of Supply Costs to Groups	$ 4,119	$ 593	$ 4,712
Hourly Billing - GSR-2 (Meter Reading)	$ -	$ 29,396	$ 29,396
Hourly Billing - GSR-2 (Large Customer Bill Preparation)	$ -	$ 56,476	$ 56,476
Total Annual Costs	$ 400,422	$ 124,554	$ 524,976
Total Annual Costs with GRT	$ 425,528	$ 132,363	$ 557,891

[1] Outside Expenses are estimates and will be amortized based on actual invoices received (reconcilable).

[2] Company Expenses will be amortized based on the amounts shown (non-reconcilable).

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. –	:	
Electric Division For Approval of	:	Docket Nos. P-2024-3049343
a Default Service Plan (DSP V) for	:	G-2024-3049351
the Period of June 1, 2025 through	:	
May 31, 2029	:	

_____

REBUTTAL TESTIMONY
OF
TRACY A. HAZENSTAB

_____

UGI ELECTRIC STATEMENT NO. 3-R

Dated: August 30, 2024

I. INTRODUCTION

Q. Please state your name and address.

A. My name is Tracy A. Hazenstab, and my business address is UGI Utilities, Inc., 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding?

A. Yes. My direct testimony, UGI Electric St. No. 3, was submitted on May 31, 2024, as Appendix D to the Petition.

Q. What is the purpose of your rebuttal testimony?

A. I am responding to certain arguments of Penn Renewables, LLC ("Penn Renewables") witness James L. Crist, P.E., related to the GSR-2 rate for customer generators. I am also responding to Office of Consumer Advocate ("OCA") witness Serhan Ogur's comments regarding UGI Utilities, Inc. – Electric Division's ("UGI Electric") reconciliation mechanism for GSR-1 customers. Additionally, I am proposing a minor clarification to the proforma tariff.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring two exhibits:

- UGI Electric Exhibit TAH-1R – Penn Renewables response to PR-I-14
- UGI Electric Exhibit TAH-2R – the revised proforma tariff.

II. RESPONSE TO PENN RENEWABLES' ISSUES

A. TIMELINE COMPLIANCE

Q. Penn Renewables states that UGI Electric has generally complied with Pennsylvania Public Utility Commission's ("Commission") regulations with respect to assisting customer-generators but has not complied with "timelines." (Penn Renewables St. No. 1, p. 13.) Please respond.

A. While there are no specific timelines around the completion of interconnection studies for Level 3 Interconnection Reviews, UGI Electric has worked to develop the necessary electrical models needed to provide study results as quickly as possible. The timelines mentioned in Mr. Crist's testimony of 90 to 120 days are not prescribed requirements within the Alternate Energy Portfolio Standards Act. However, UGI does not dispute that 90 to 120 days may reflect Penn Renewable's experience with other utilities that already have differing levels of mature processes focused on the review of these large application requests. UGI Electric has contracted with an outside firm for this work as the Company does not maintain in-house expertise or the necessary engineering models to conduct the required analysis that is necessary to allow for the safe interconnection of these large-scale generation projects. This contractor work is vital to ensure that any needed system reinforcements are identified and that existing UGI customers are not impacted in a negative way by the interconnection of these large, distributed generation resources.

UGI Electric has recently received information from its consultant, which includes the following estimated schedule for completion of the model build and various studies related to Penn Renewable projects:

- Completion of the engineering models by September 14, 2024.

- Completion of the Feasibility Study ("FS") 30 business days after the models are completed.
- Completion of the System Impact Study ("SIS") 45 business days after the FS is completed.
- Completion of the Facilities Study 45 business days after the SIS is completed.

B. SUPPLY PEAK LOAD IMPACT

Q. Mr. Crist provides numerous criticisms related to the Company's proposal to utilize supply peak load impact ("SPLI") as the determinant related to default service under GSR-1 (below 100kW SPLI) or GSR-2 (100kW and above SPLI). How do you respond?

A. While Mr. Crist notes that setting distribution rates based on demand is fairly normal, he is not aware of any electric utilities in Pennsylvania using peak supply to establish commodity rates that are paid to customer generators and that UGI Electric should not be permitted to do so. (Penn Renewables St. No. 1, p. 20.) The fact that no other electric utilities in Pennsylvania have utilized supply peak load impact to-date is not a prohibition on the Commission considering and approving UGI Electric's proposal. Importantly, large scale customer-generators have significant and material differences to an EDC's distribution system and supply management activities than what a "typical" small commercial customer having a SPLI of less than 25 kW may create. I am advised by counsel that under the Commission's rulemaking related to the regulations defining small commercial customers as less than 25kW, there was no discussion or consideration related to large customer-generators with material generation capability (say 1 MW and above) but having low power consumption characteristics being qualified as a small customer. As

evidenced by the detail provided above related to review, approval, and management of such large-scale customer-generator project installations, specific and highly sophisticated engineering models, feasibility studies, system impact studies and facility studies are needed for such installations and require a significant amount of time and effort. From the standpoint of developing a default service supply portfolio, large scale customer-generators present specific risk considerations, as UGI Electric witness Mr. Rouland addressed in his direct testimony.

Further, the Commission has already recognized that customers with load impacts of 100 kW and greater should be considered in a separate default service group as part of UGI Electric's current DSP IV plan (GSR-2 group) and several other default service plans approved by the Commission. The Company's proposal simply reflects that from a supply impact standpoint, both consumption *and generation* demand impacts create material concerns that warrant group differentiation. Of note, the projects Penn Renewables has planned on the UGI Electric system of 1-2 MW in size are *10 to 20 times* the 100 kW level considered material within the context of providing default service. (Penn Renewables St. No. 1, p. 4.) According to the Energy Information Administration, all of these projects are considered to be "utility-scale"[1]. Thus, utilizing SPLI to assess those customers above and below the 100 kW level drives clarity and comparability to UGI Electric's default service offerings among all customers.

Moreover, Mr. Crist notes that most of Penn Renewable's systems, if not all, would be considered "small business" customers because they "will have less than 25 kW of peak load." He also notes that Act 129 does not define the term "small business customers" and

[1] https://www.eia.gov/todayinenergy/detail.php?id=38272

that "small business customer" is defined in the Commission's regulations as "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." (Penn Renewables St. No. 1, pp. 22-23.) I am advised by counsel that Mr. Crist's argument fails to account for and properly apply the Commission's regulations. Mr. Crist is correct that Act 129 does not define the term "small business customers" and that "small business customer" is defined in the Commission's regulations as "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." 52 Pa. Code § 54.2 (emphasis added). However, Mr. Crist conflates his use of the term "peak load" with the Commission's definition of "maximum registered peak load." (Penn Renewables St. No. 1, p. 23.) In fact, Section 54.2 of the Commission's regulations defines "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 EDC tariff in a particular service territory**." 52 Pa. Code § 54.2 (emphasis added). The Company's SPLI proposal is indeed a further definition that the Company believes is appropriate when addressing default service considerations and is requesting Commission approval thereof in this proceeding for the reasons contained in the Company's supportive testimony. The differentiators between a small business customer with less than 25 kW consumption demand and a large-scale, indeed utility-scale, customer-generator with 1-2 MW

generation capability, despite a consumption demand of less than 25 kW when not generating, are clear. Accordingly, the Company's SPLI criteria for differentiating GSR-1 and GSR-2 customers above and below 100 kW SPLI should be adopted.

Q. Mr. Crist suggests that customer generators should be able to choose if they want the GSR-1 or GSR-2 rate. (Penn Renewables St. No. 1, p. 28.) Do you agree?

A. No, customer-generators should be subject to classification utilizing their SPLI along with all other non-generator default service customers. Allowing customer self-selection would undermine the purpose of having separate GSR-1 and GSR-2 rates, would create unnecessary complexity to the procurement process for GSR-1 supply, and would subsequently increase the risk to wholesale suppliers providing GSR-1 supply, likely increasing the resulting contract costs.

Q. Mr. Crist also suggests that UGI Electric increase the GSR-2 threshold to 3 MW for customer generators. (Penn Renewables St. No. 1, p. 28.) Does UGI Electric agree with this proposal?

A. No. The customer thresholds for GSR-1 and GSR-2 are set to reflect the impact a group of customers will have on supply activity based on SPLI. This approach is discussed in further detail in Mr. Rouland's Direct Testimony, page 29, lines 19-23, along with Mr. Rouland's Rebuttal Testimony, pages 20 - 21.

C. GSR-2 RATE CALCULATION

Q. Mr. Crist provides numerous criticisms related to the calculation and application of the Company's GSR-2 rate when applied to customer-generators who are net metering including how it does not appear to comport with legislative or regulatory requirements. How do you respond?

A. Mr. Crist avers several criticisms related to the GSR-2 rate, including:

1. The GSR-2 rate is a wholesale rate (Penn Renewables St. No. 1, p. 15.)
2. The GSR-2 rate is not a "default service rate." (Penn Renewables St. No. 1, p. 18, line 16.)
3. The GSR-2 rate for customer generators and non-customer generators will not be the same each hour. (Penn Renewables St. No. 1, p. 19, lines 4-8.) Also, that customer generators should not be subject to the GSR-2 rate because it is not stable. (Penn Renewables St. No. 1, p. 28.)
4. The GSR-2 rate is not a "single rate option" as required by 52 Pa. Code 54.187(c). (Penn Renewables St. No. 1, p. 25)

I will address why each of these concerns expressed by Mr. Crist is incorrect below:

1. The GSR-2 rate is not a wholesale rate. As clearly shown in UGI Electric's Pro Forma Tariff, page 41, which was included with the Petition as Appendix A, the GSR-2 rate formula includes numerous rate components. Specifically, GSR-2 includes:
    - HEC = Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 Customer by multiplying the Customer's actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.

- HPC = Other power costs incurred by the Company to acquire electric supply for the GSR-2 group for the month shall be allocated to each GSR-2 Customer based on metered sales. Other power costs include alternative energy credits and all PJM bill line-item expenses/credits excluding the following: costs for capacity services, transmission services, network transmission service credits and firm point-to-point transmission service credits/expenses. Other costs included are administrative costs, net metering costs related to required excess power purchases pursuant to PTC-2, legal costs, taxes, and any other applicable costs of providing default service for the GSR-2 group.
- HTC = Cost for capacity and transmission services based on the PJM bill line-item expenses/credits applicable to these services shall be allocated to each Customer in the GSR-2 group. The capacity costs shall include the PJM bill line items for locational reliability, capacity transfer rights, RPM auction, and capacity resource deficiency. The capacity costs shall be allocated to each Customer based on each Customer's peak load contribution (PLC). The transmission costs shall include the PJM bill line items for network integration transmission service charges, transmission enhancement service charges/credits, and non-firm point-to-point transmission service charges/credits. The transmission costs shall be allocated to each Customer based on each Customer's network service peak load value (NSPL). Any expense/credit line items added by PJM related to

these services shall be allocated based on the Customer's applicable PLC and NSPL.

- T = All costs for GSR-2 Customers shall include the Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates.

While one of these rate components is related to the spot market energy cost incurred to acquire electric supply, the PJM Interconnection, LLC ("PJM") Locational Marginal Price ("LMP"), which is part of the defined "HEC" element of the rate, there are numerous additional costs which are included in the total GSR-2 retail rate that is assessed to applicable customers. As such, the GSR-2 rate is not a wholesale rate as Mr. Crist avers.

2. The GSR-2 rate is a "default service rate." As I have demonstrated in response to 1, above, the GSR-2 default service rate is detailed within UGI Electric's pro-forma tariff in this proceeding. The Company has maintained a GSR-2 default service rate throughout DSP I, DSP II, DSP III, and DSP IV. The fact that the rate is hourly based has no bearing on whether it is or is not a "default service rate." The Commission has approved numerous default service rates that are hourly based[2]. Mr. Crist's assertion that it is not a default service rate is incorrect.

3. The GSR-2 rate for customer generators and non-customer generators is calculated on the same basis for each hour. The GSR-2 rate contains customer-specific billing determinants which are based on kW demand values (PLC and NSPL) and kWh

[2] Please see PPL's GSC-2 tariff at: https://pplelectric.com/-/media/PPLElectric/At-Your-Service/Docs/Current-Electric-Tariff/GenerationSupplyCharge2GSC206012021.ashx?sc_lang=en&hash=03D9707210C1348F62FE6961AC5213F5 and PECO's GSA-2 rate (tariff page 41) at: https://azure-na-assets.contentstack.com/v3/assets/blt1b5616c79bacadb4/blt9448ea371fcf175a/6682c22414eed0000de60624/Current_Electric_Tariff_Effective_July_1_2024.pdf?branch=prod_alias

consumption (or production) values. UGI Electric provided sample calculations of the GSR-2 rate which show respective kW and kWh-based rate elements in response to PENN-I-2 demonstrating that the calculation is the same for both customer-generators and non-customer-generators. Mr. Crist provided a copy of PENN-I-2 as Exhibit JC-4 to his testimony. As is clearly seen on that exhibit, Line 9 (LMP), Line 12 (PJM allocated charges - PLC based), Line 13 (PJM allocated charges - NSPL based), Line 14 (PJM allocated charges/(credits) – kWh based), and Line 16 (DSP A&G allocated charges – kWh based) are all applying the identical "rate" to both the consumption and generation example hours. GRT and STAT values, Lines 20 and 21 are also the same "rates". It is only the customer specific kW and kWh values in these example hours which differ and, thus, drive differing resulting total charges under GSR-2.

4. The GSR-2 rate is a "single rate option" as required by 52 Pa. Code 54.187(c). 52 Pa. Code 54.187(c) states that "…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." The GSR-2 rate, as defined in the tariff, recovers all energy costs for the customer group and is the price to compare (PTC-2) for GSR-2 customers, once adjusted for STAS. GSR-2 is a single rate option. Pursuant to the Company's proposal, all customers with an SPLI greater than or equal to 100kW will have this single rate as their default service option. It is possible Mr. Crist may be confusing single rate option with a fixed rate. GSR-2 is not a fixed rate. Accordingly, Mr. Crist's assertion that GSR-2 is not compliant with 52 Pa. Code 54.187(c) is incorrect.

D. NET METERING AND EXCESS GENERATION

Q. Mr. Crist presents several criticisms related to how UGI Electric will track and compensate net metering amounts for customer-generators who receive service under GSR-2. How do you respond?

A. Mr. Crist presents several criticisms, including:

1. Stating that…"*rather than carry forward kWh of excess generation, that UGI is planning to determine the value at the end of each billing period and carry forward that amount. What that means is that at the end of the year, there will be no compensation at the PTC for all excess kWh credits.*" (See Penn Renewables St. No. 1, p. 18, lines 11-14.)
2. Stating that…"UGI's proposal fails to compensate net metered customer-generators at the full retail value of the energy they produce. (Penn Renewables St. No. 1, p. 21, lines 13-14.)
3. Stating that the PTC will not recover all default service costs of the "average member of a customer rate class" because the PTC will be different for each customer on the rate and for each hour. (Penn Renewables St. No. 1, p. 26, lines 5-10.)

I will respond to each of the above criticisms to clarify the Company's net metering tracking and compensation determination below:

1. Excess generation will be carried forward and compensated at the PTC-2 rate that is applicable for the hour of excess generation. GSR-2 customer-generators, including Penn Renewables, will then be compensated for any banked excess generation production after the PJM Planning Year end on May 31st. Consumption

and generation will be tracked on an hourly basis, in accordance with GSR-2's hourly pricing structure. Thus, excess kWh and excess kWh value will be carried forward hour-to-hour, day-to-day and month-to-month at the PTC-2 rate applicable for each hour until the end of the PJM planning year. The balance of the excess kWh value will then be paid as compensation to the customer-generator after the conclusion of the PJM planning year. Based on data provided by Penn Renewables as related to their anticipated hourly power generation and consumption, each month Penn Renewables is anticipated to fully offset any power consumption during the billing month and carry an excess into the subsequent month. Thus, it is anticipated that Penn Renewables will receive a full retail rate credit for all hours having net power consumption and be paid the PTC-2 rate for all excess generation. This approach comports with the Commission's regulations. Thus Mr. Crist's assertion that there will be no compensation at the PTC is incorrect.

2. Full retail value is appropriately recognized as part of the customer-generator metering and billing process. Given the tracking outlined in 1, above, hours of consumption will be offset fully by any excess production amounts based on a running cumulative total throughout the month. For large customer-generators such as Penn Renewables, excess production is anticipated to be far greater than any consumption amounts during a monthly billing period. Thus, no distribution charges which are consumption based will be assessed for the billing period – providing for fully retail value offset to the customer-generator. GSR-2 customer-generators will be compensated for their generation in compliance with the Commission's regulations. Although Mr. Crist believes that the Commission's

regulations fail to comply with the AEPS Act because, according to him, the year-end cash-out at the PTC does not "constitute 'full retail value'" due to the absence of "distribution or other charges typically included in a retail rate" (see UGI Electric Exhibit TAH-1R [Response to UGI to PR-I-14(a)]), I am advised by counsel that the Commission's regulations properly compensate customer-generators for the value of their generation.

3. The average customer for the GSR-2 group is a customer with SPLI greater than 100 kW, either from the system or into the system. As explained in my previous response, the GSR-2 rate recovers all energy costs for the customer group. The fact that the GSR-2 rate PTC may be different for each customer on the rate does not mean that all default service costs will not be recovered from the average member of the GSR-2 class. The pass-through charges for this customer group varies hourly due to a number of factors, including LMP rate variability and customer-specific factors, such as usage, as I have explained in detail above.

E. OTHER RATE DESIGN ITEMS

Q. Mr. Crist states that Act 129 requires that "small business customers" be provided a rate that changes no more than quarterly and that most GSR-2 customer generators of Penn Renewables' systems, if not all, would be considered "small business" customers because they "will have less than 25 kW of peak load." (Penn Renewables St. No. 1, pp. 22-23.) Do you agree with this contention?

A. No. As discussed previously, the Company does not agree that the Penn Renewables' systems would classify as a "small business". Net metering customers are defined as "customer generators" under the AEPS Act and are not classified as "small business"

customers. See Mr. Rouland's rebuttal testimony for additional explanation regarding why Penn Renewables systems are not like "small business" customers. Furthermore, the Commission's regulations permit the adjustment of default service rates for customers with maximum registered peak load of 25 kW to 500 kW more frequently than on a quarterly basis, to acquire electricity at the least cost to customers over time. Specifically, Section 54.187(i) of the Commission's regulations states: "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." 52 Pa. Code § 54.187(i). As explained in Mr. Rouland's rebuttal testimony (UGI Electric St. No. 2-R), the Company's proposed classification of GSR-1 and GSR-2 customers is necessary to ensure that the Company can procure supply for default service customers at the least cost over time. Further, if the Commission deems it to be necessary, UGI Electric requests a waiver of the 25 kW peak load threshold in order for large customer generators to be classified as GSR-2 default service customers for the reasons set forth by the Company in this proceeding.

III. RESPONSE TO OCA'S RECONCILIATION MECHANISM PROPOSAL

Q. Please explain Mr. Ogur's proposal with respect to the Company's reconciliation mechanism for GSR-1 customers.

A. Mr. Ogur is recommending the Company utilize a 12-month amortization period for over- or under-collections balances reconciled over a six-month period.

Q. Do you agree with Mr. Ogur's proposal?

A. Yes, the Company can agree with Mr. Ogur's proposal and will make the appropriate tariff updates.

IV. TARIFF REVISIONS

Q. Does the Company have any clarifications to make to its proforma tariff that was included in this proceeding?

A. Yes. The Company is proposing additional specific language to address an annual reconciliation element of the rate calculation for the GSR-2 customers. As noted in the Company's response to PENN-III-19, net metering excess generation will otherwise lower PJM purchases and require the Company to purchase an equivalent amount of generation supply from such net metering customer-generators. This will result in a difference in total costs versus total revenues on an annual basis for the GSR-2 group. While the Company's proposed tariff related to the specifics of GSR-2 include "net metering costs related to required excess power purchases pursuant to PTC-2," as seen on pro-forma tariff page 41 under the "HPC" element of the GSR-2 formula, the specifics of how these costs will be tracked and incorporated are best further detailed in the tariff. The reconciliation amount will be determined for each period ending May 31 by comparing the total GSR-2 costs (all purchase costs, inclusive of payments related to net metering excess generation purchase amounts) with total GSR-2 revenues (all billed GSR-2 revenues). A revised tariff with proposed additions to address this reconciliation detail is included as UGI Electric Exhibit TAH-2R.

Q. Does this conclude your rebuttal testimony at this time?

A. Yes.

UGI ELECTRIC
Exhibit TAH-1R

RESPONSES OF
PENN RENEWABLES, LLC
TO INTERROGATORIES AND
REQUESTS FOR PRODUCTION OF DOCUMENTS
TO UGI UTILITIES, INC. – ELECTRIC DIVISION, SET I

Docket Nos. P-2024-3049343
C-2024-3049618

UGI to PR-I-14

Re: Penn Renewables St. No. 1, pp. 15-17.

(a) Please explain in detail whether the Price to Compare is a retail rate or a wholesale rate.

(b) Please provide any Documents, studies, analyses, or workpapers relied upon in responding to subpart a, *supra*.

RESPONSE:

(a) The Price To Compare is a retail rate, but does not constitute "full retail value" because it does not include distribution and other charges typically included in a retail rate and is therefore not compliant with the AEPS Act. The Commission's regulations and policy statements are clear that for customers with registered peak load of less than 25 kW, the utility must provide a product that is based on laddered contracts, not the hourly LMP. To the contrary, the rate is not supposed to change more frequently than quarterly. See 52 Pa. Code § 69.1805, 52 Pa. Code § 54.188(g).

(b) N/A.

Provided By: James Crist

UGI ELECTRIC
Exhibit TAH-2R

UGI UTILITIES, INC. – ELECTRIC DIVISION

ELECTRIC SERVICE TARIFF

RULES AND RATES
FOR ELECTRIC DISTRIBUTION SERVICE AND
CHOICE AGGREGATION SERVICE

in the following service territory:

LUZERNE COUNTY

City of Nanticoke, and Boroughs of Courtdale, Dallas, Edwardsville, Forty-Fort, Harvey's Lake, Kingston, Larksville, Luzerne, New Columbus, Plymouth, Pringle, Shickshinny, Sugar Notch, Swoyersville, Warrior Run, West Wyoming and Wyoming.

First Class Townships of Hanover and Newport, and Second Class Townships, of Conyngham, Dallas, Fairmount, Franklin, Hunlock, Huntington, Jackson, Kingston, Lake, Lehman, Plymouth, Ross and Union.

WYOMING COUNTY

Townships of Monroe and Noxen

Issued: Effective for Service Rendered on and after:

Issued by:
Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

THIS TARIFF MAKES CHANGES TO THE EXISTING RATES (PAGE 2).

LIST OF CHANGES MADE BY THIS SUPPLEMENT

(Page Numbers Refer to Official Tariff)

Pursuant to the Final Order entered _____ approving the Default Service Program at Docket No. _____, the following changes have been made to incorporate default service rules beginning June 1, 2025 along with calculated default generation supply service rates effective June 1, 2025:

Rules and Regulations – 17. Net Metering, Pages 30 – 32

- 17-a(3) – Removed rate schedule names for customer types.
- 17-a(4) – Removed outdated language requiring that customer-generators have independent load. Renumbered items 17-a(5)-(7) to 17-a(4)-(6).
- 17-c(1) – Added language to clarify the Price to Compare that will be used to calculate compensation owed to customer-generators and the timeframe used to define the calculation cycle. Also, added language to define the calculation for compensation to customer-generators served under GSR-2.
- 17-e & 17-f – Removed rate schedule names.
- 17-g – Added language to define the payment distribution timeline.

Rider B – Generation Supply Service Surcharge, Pages 39-41

- Dates have been revised to reflect the Default Service rules beginning June 1, 2025.
- Revised GSR assignment to be based on supply peak load impact and added definition of supply peak load impact.
- Revised timeframe of GSR classification to be determined annually.
- Revised rate calculation frequency from quarterly to semi-annually.
- Added interim filing language for GSR-1.
- Revised GSR-1 formula to include “F” – relative cost factor and added the definition.
- Deleted references to transmission revenue from the EC calculation definition and GSR-2 costs.
- Updated ECA, SEC, Sint language to align with proposed rate updates.
- Added Non-Residential GSR-1 Rate.
- Eliminated migration rider and reverse migration rider from GSR-1 and GSR-2 customers.
- Added formula to show calculation of GSR-2 rate. Added reconciling components to costs.
- Clarified definition of Price to Compare for GSR-1 customers. Added language to define Price to Compare for GSR-2 customers.
- Clarified information to be provided in annual reconciliation statement. Added an annual reconciliation for GSR-2 customers.

RULES AND REGULATIONS (continued)

17. NET METERING

17-a Applicability. This rule sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

(1) Customer-generators served under Rate Schedules R, GS-1, GS-4, GS-5, and LP who install a device or devices which are, in the Company's judgment, subject to Commission review a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system are eligible for net metering.

(2) This rule is available to installations where any portion of the electricity generated by the renewable energy generating system offsets part or all of the customer-generator's requirements for electricity.

(3) A renewable customer-generator, under this rule, is a non-utility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service ~~(Rate R)~~ or not larger than 3,000 kilowatts at other customer service locations ~~(Rate GS-1, GS-4, GS-5, and LP)~~, except for a Customer whose system is above 3 megawatts and up to 5 megawatts who may qualify its alternative energy system for customer-generator status if, as set forth in the Commission's regulations: (a) the Customer makes its system available to operate in parallel with the grid during grid emergencies; or (b) the Customer's system is located within a microgrid. **(C)** **(C)**

~~(4) To qualify for net metering, the customer-generator must, among other things, have electric load, independent of the alternative energy system, behind the meter and point of interconnection of the alternative energy system. To be independent of the alternative energy system, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system.~~ **(C)**

(4) Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. The net metering rules are not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

(5) Service is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

(6) Review and approval of all customer-generator applications and interconnections shall be in accordance with the Commission's regulations.

17-b Metering Provisions. A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. If the Customer agrees, a dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

(C) Indicates Change

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

(3) Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternate energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for the disposition of those credits.

(4) Virtual meter aggregation on properties owned or leased and operated by the same customer-generator shall be allowed for purposes of net metering. Virtual meter aggregation shall be limited to meters located on properties owned or leased and operated by the same customer-generator within two (2) miles of the boundaries of the customer-generator's property and within the Company's service territory. All service locations to be aggregated must be Company service location accounts held by the same individual or legal entity receiving retail electric service from the Company and have measurable load independent of any alternative energy system. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing their account on a virtual meter aggregation basis.

17-c Billing Provisions. The following billing provisions apply to customer-generators in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at full retail rate, consistent with Commission regulations. If a customer-generator supplies more electricity to the electric distribution system than the Company delivers 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-generator in subsequent billing periods shall continue to accumulate until the ~~end of the year.~~final billing period on or before the end of the PJM year (May of each year). At the end of each PJM year, the Company will 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 ~~Company's~~ Customer's applicable Price to Compare (PTC-1 or PTC-2). Applicable PTC-2 rates shall be applied to the respective hours of excess generation. ~~(PTC-1) rate for customers receiving default service on GSR-1.~~ The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule. **(C)** **(C)** **(C)** **(C)**

(C) Indicates Change

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

(3) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs must be stated in the service agreement between the customer-generator and the EGS. The Company shall credit customer-generators who are EGS customers for each kilowatt-hour of electricity produced at the Company's unbundled distribution kilowatt-hour rate. The distribution kilowatt-hour rate credit shall be applied monthly against kilowatt-hour distribution usage. If the customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in any billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's unbundled kilowatt-hour distribution usage in subsequent billing periods until the end of the year when all remaining unused kilowatt-hour distribution credits shall be zeroed-out. Distribution credits are not carried forward into the next year.

(4) 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. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by the same customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

17-d Application. Customer-generators seeking to receive service under the provisions of this rule must submit a written application to the Company demonstrating compliance with the net metering provisions and quantifying the total rated generating capacity of the customer-generator facility.

17-e Minimum Charge. The Minimum Charges under ~~Rate Schedule R, GS-1, GS-4, GS-5, and LP~~the applicable rate schedule apply for installations under the net metering rules. **(C)**

17-f Applicable Charges and Fees. Bills rendered by the Company under this rule shall be subject to charges and fees applicable to ~~Rate Schedules R, GS-1, GS-4, GS-5, and LP.~~the assigned rate schedule. **(C)**

17-g Payment distribution. Any remaining credit balance as of the end of the May billing period will be paid to the customer via check within 90 days of May 31. **(C)**

(C) Indicates Change

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE

Company will supply Default Generation Supply Service (GSS) to Customers in the Company's service territory not receiving service from an EGS. The rules and rates contained herein apply to service provided on and after June 1, ~~2021~~2025. **(C)**

For Customers served through the Company's GSS, a Generation Supply Rate (GSR) shall be applied to each kilowatt hour of energy used by the Customer. Separate GSRs shall be calculated ~~and apply to the rate schedules listed below~~and apply in accordance with the following:~~.~~ **(C)** **(C)**

GSR-1 shall apply to all residential customers as well as non-residential customers with a supply peak load impact less than 100 kW. **(C)**

GSR-2 shall apply to all non-residential customers with a supply peak load impact greater than or equal to 100 kW. **(C)**
~~GSR-1 shall apply to Rate Schedules R, GS-1, GS-5, FCP, BLR, OL, SOL, MHOL, LED-OL, SL, SSL, MHSL, LED-SL and LED-CO.~~
~~GSR-1 shall also apply to Rate Schedules GS-4 and LP where the Customer's annual peak load is less than 100 kW.~~
~~GSR-2 shall apply to Rate Schedules GS-4, LP, and HTP where the Customer's annual peak load is greater than or equal to 100 kW.~~

Supply peak load impact will be determined on 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. **(C)**

The supply peak load impact used to assign customers to the applicable GSR rate shall be the Customer's highest supply peak load impact (kW) in the most recent 12-month period ending September 30. ~~Customer's highest billing demand in the twelve-month period ending September 30, 2020 shall be the annual peak load determinant for purposes of applying the GSR.~~ For new Customers without a twelve-month billing history, the ~~billing demand~~ supply peak load impact shall be based on the Company's estimate using factors such as, but not limited to, similarly equipped buildings, 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. **(C)** **(C)**

The GSR-1 rate shall be calculated every ~~three~~ six months beginning June 1, ~~2021~~2025. The GSR-1 rate shall be filed with the Commission with at least thirty days' notice prior to each ~~three~~six-month period and shall be posted on the Company's website. If the GSR-1 calculation results in a change in rate that is less than 2%, the Company, in its sole discretion, may file with the Commission a GSR-1 rate that is unchanged from the prior period. Pursuant to 52 Pa. Code § 69.1809(c), the Company may propose an interim reconciliation prior to the next adjustment interval. The rate will be calculated as follows: **(C)** **(C)**

$$GSR\text{-}1 = (((EC*F)/SEC) + (ECA/SECA) + (Int/Sint)) * (1/(1-T)) \quad \textbf{(C)}$$

EC = Projected direct and indirect purchased power costs incurred by the Company to acquire electric supply for the GSR-1 group for the next ~~three-month~~computation period including, a load following service, wholesale energy costs, alternative energy credits, capacity costs, transmission costs, and all other PJM bill line item expenses/credits excluding network transmission service credits and firm point-to-point transmission service credits/expenses. EC also includes administrative costs, legal costs, taxes, net metering costs related to required excess power purchases at the PTC-1 rate, and any other applicable costs of providing default service for the GSR-1 group. ~~The estimated EC shall be reduced by the estimated transmission revenues to be collected in accordance with the applicable rate schedules included in the GSR-1 group.~~ **(C)** **(C)** **(C)**

(C) Indicates Change

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE (continued)

F = Relative Cost Factor, updated at the beginning of the plan period on June 1, 2025. However, should the supply load change by more than 50% during the course of the application period, the Company will update the relative cost factors. The Relative Cost Factor reflects the load shape of the residential and non-residential classes and is: **(C)**

Application Period	Residential	Non-Residential
June 1, 2025 – May 31, 2029	1.02	0.93

ECA = Net over or under collection of the EC defined above to be refunded/recovered and calculated across relative cost factors. The ECA will be reconciled ~~quarterly~~ based on actual EC revenues received and actual EC costs incurred for the ~~three~~six-month period ending two months prior to the filed GSR effective date. ~~Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-1 Customers shall be included in the ECA component of the GSR-1 beginning June 1, 2021. The over/under collection existing as of May 31, 2021 shall be allocated to GSR-1 and GSR-2 Customers based on the percentage of the actual sales during the period of the over/under collection attributed to those Customers classified as GSR-1 and GSR-2 as of June 1, 2021.~~ In the event the ECA would result in less than (or equal to) a five percent (5%) change in the average total Residential bill, the Company will refund/recover the balance over a ~~three~~six-month period. In the event the ECA would result in more than a five percent (5%) change in the average total Residential bill for default service, the Company will refund/recover the balance over a ~~six, nine, or~~ twelve-month period ~~(as determined by the Company)~~. **(C)** **(C)** **(C)** **(C)**

Int = 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.

T = The Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates, expressed in decimal form.

SEC = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the next ~~three-month~~computation period, in kilowatt hours. **(C)**

SECA = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the refund/recover period, in kilowatt hours.

Sint = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the ~~twelve-month period beginning December 1~~next computation period, in kilowatt hours. **(C)**

The current GSR-1 rate (in ¢/kWh) is: **(C)**

Residential	Non-Residential
x.xx	x.xx

(C)

~~10.525 ¢/kWh~~

~~GSR-2 shall be calculated for each default service Customer in this group. Company shall bill each Customer on a calendar month based upon actual costs incurred to serve the Customer. The costs will be allocated as follows:~~ **(C)**

~~Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 Customer by multiplying the Customer's actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.~~

~~(~~**(C) Indicates Change**

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE (continued)

GSR-2 shall be calculated for each default service Customer in this group. Company shall bill each Customer on a calendar month based upon actual costs incurred to serve the Customer, along with a reconciliation mechanism. The costs will be allocated as follows: **(C)**

GSR-2 = (HEC + HPC + HTC) + ((HECA + HIN)/12) * (1/(1-T)) **(C)**

HEC = Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 Customer by multiplying the Customer's actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.

HPC = Other power costs incurred by the Company to acquire electric supply for the GSR-2 group for the month shall be allocated to each GSR-2 Customer based on metered sales. Other power costs include alternative energy credits and all PJM bill ~~line item~~line-item expenses/credits excluding the following: costs for capacity services, transmission services, network transmission service credits and firm point-to-point transmission service credits/expenses. Other costs included are administrative costs, net metering costs related to required excess power purchases pursuant to PTC-2, legal costs, taxes, and any other applicable costs of providing default service for the GSR-2 group. ~~The actual costs shall be reduced by the actual transmission revenues to be collected in accordance with the applicable rate schedules included in the GSR-2 group.~~ **(C)**

HTC = Cost for capacity and transmission services based on the PJM bill ~~line item~~line-item expenses/credits applicable to these services shall be allocated to each Customer in the GSR-2 group. The capacity costs shall include the PJM bill line items for locational reliability, capacity transfer rights, RPM auction, and capacity resource deficiency. The capacity costs shall be allocated to each Customer based on each Customer's peak load contribution (PLC). The transmission costs shall include the PJM bill line items for network integration transmission service charges, transmission enhancement service charges/credits, and non-firm point-to-point transmission service charges/credits. The transmission costs shall be allocated to each Customer based on each Customer's network service peak load value (NSPL). Any expense/credit line items added by PJM related to these services shall be allocated based on the Customer's applicable PLC and NSPL. **(C)**

HECA = Net over or under collection of the HEC, HPC, and HTC as defined above to be refunded/recovered over a 12-month period beginning September. The HECA will be reconciled based on actual revenues received and actual costs incurred for the twelve-month period ending May 31 and will be amortized over 12-months beginning September. The HECA shall be allocated to each Customer based on each Customer's PLC. **(C)**

HIN = 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. The HIN will be amortized over 12-months beginning September and shall be allocated to each customer based on each Customer's PLC. **(C)**

~~Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-2 Customers that migrate from rate GSR-1 shall be refunded/recovered from those Customers directly over 12 billing periods beginning September 1, 2021. The over/under collection existing as of May 31, 2021 shall be allocated to GSR-1 and GSR-2 Customers based on the percentage of the actual sales during the period of the over/under collection attributed to those Customers classified as GSR-1 and GSR-2 as of June 1, 2021. Customers who undergo reverse migration, switching from GSR-2 to GSR-1 during the DSP IV term, will be exempted from any over/under collections as reflected in the Company's E-factor (existing as of May 31, 2021) for a period of 12 months after returning to GSR-1.~~

T = All costs for GSR-2 Customers shall include the Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates.

Price to Compare: The Price~~-To-~~ to Compare (“PTC”) for GSR-1 (PTC-1) shall include the ~~Energy Charge (“EC”), and the Energy Cost Adjustment (“ECA”), contained in this Tariff. The Price-To-Compare shall also include the~~GSR-1 rate and the State Tax Surcharge in Rider A. Separate PTC-1 rates will apply to residential and non-residential customers. ~~PTC is not applicable to GSR-2.~~The Price to Compare for GSR-2 (PTC-2) shall include the GSR-2 rate and the State Tax Surcharge in Rider A. **(C)**

Annual Reconciliation Statement: On June 30 of each year, the Company will file with the Commission, its Annual Reconciliation Statement for the GSR-1 (with the actual costs and revenue for both residential and non-residential customers aggregated) and GSR-2 rates, ~~for~~for the preceding 12 months ending May 31. **(C)**

(C) Indicates Change

Issued:	Effective for Service Rendered on and after

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. –	:	
Electric Division For Approval of	:	Docket Nos. P-2024-3049343
a Default Service Plan (DSP V) for	:	G-2024-3049351
the Period of June 1, 2025 through	:	
May 31, 2029	:	

REJOINDER TESTIMONY
OF
TRACY A. HAZENSTAB

UGI ELECTRIC STATEMENT NO. 3-RJ

Dated: October 1, 2024

I. INTRODUCTION

Q. Please state your name and address.

A. My name is Tracy A. Hazenstab, and my business address is UGI Utilities, Inc., 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding?

A. Yes. My direct testimony, UGI Electric St. No. 3, was submitted on May 31, 2024, as Appendix D to the Petition. My rebuttal testimony, UGI Electric St. No. 3-R, was submitted on August 30, 2024.

Q. What is the purpose of your rejoinder testimony?

A. I am responding to certain arguments in the surrebuttal testimony of Penn Renewables, LLC ("Penn Renewables") witness James L. Crist, P.E., related to the GSR-2 rate for customer generators. I am also responding to Office of Small Business Advocate ("OCA") witness Mark Ewen's comments in surrebuttal testimony regarding UGI Utilities, Inc. – Electric Division's ("UGI Electric") request for a waiver of the 25 kW peak load threshold in order for large customer generators to be classified as GSR-2 default service customers.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes, I am sponsoring UGI Electric Exhibits TAH-1RJ - TAH-3RJ, which are defined in further detail in my rejoinder.

II. FULL RETAIL VALUE IN UGI'S SYSTEM

Q. Mr. Crist has offered a definition of "full retail value" in UGI Electric's system (Penn Renewables St. No. 1-SR, p. 4). Would you agree with his definition?

A. No. In DSP V, the Company will have two separate, full retail value price-to-compare rates, PTC-1 for GSR-1 customers and PTC-2 for GSR-2 customers. UGI Electric's response to Penn-I-2, which is provided as UGI Electric Exhibit TAH-1RJ, provides a line-item calculation of PTC-2 with example consumption and generation kWh values based on actual May 2024 billing rates applicable to UGI Electric's GSR-2 customers. Please note this response has been updated to reflect changes related to PLC and NSPL-based charges as discussed later in my testimony.

Q. Please explain the line items included in the response to Penn-I-2.

A. Line 1 shows hypothetical kWh values for a net-consuming customer and a net generating customer. These metered values are grossed up to include all applicable line losses to calculate the billing kWh shown on Line 8. Lines 9 and 10 assume PJM LMP rate values of $40/MWh or the equivalent $0.04/kWh, respectively. Line 11 calculates the PJM LMP charges applicable for the example hour by multiplying the $/kWh rate shown on Line 10 by the kWh shown on Line 8. Line 12 contains any PLC-based PJM capacity charges. These charges are allocated by dividing the total PLC-based charges by the total net GSR-2 PLC values to determine the per unit of PLC rate that will be assessed. Line 13 includes any NSPL-based PJM charges, which include various transmission charges. These charges are allocated by dividing the total NSPL-based charges by the total net GSR-2 NSPL values to determine the per unit of NSPL rate that will be assessed. In the hypothetical example, the Company assumed net consumption on

50% of the NSPL-hours. When calculating the actual compensation to a net-generator, these calculations would be based on the customer's actual generation or consumption. Line 14 includes those PJM billing items that are allocated to GSR-1 and GSR-2 based on sales volumes. These include all remaining PJM items. Line 16 accounts for any UGI Electric administrative and general items that have been approved for recovery in the Company's currently active DSP plan. These costs are allocated to GSR-1 and GSR-2 as described in UGI Electric Statement No. 3, p. 8-10. Line 18 is the reconciliation for GSR-2 as described in UGI Electric Statement No. 3-R, p. 15. Line 20 adjusts the total GSR-2 components for the current GRT and Line 21 will apply the currently applicable STAS rate to all above GSR-2 components. Line 23 is the per kWh PTC-2 for the example hour.

III. RESPONSE TO PENN RENEWABLES' ISSUES

A. TIMELINE COMPLIANCE

Q. Penn Renewables states that UGI Electric is not supporting timely development of solar projects by not meeting "promised" deadlines and does not have the expertise to evaluate and understand safe interconnection (Penn Renewables St. No. 1-SR, p. 22.) Please respond.

A. While Mr. Crist states that UGI Electric "promised completion of the engineering models by September 13, 2024", Mr. Crist fails to acknowledge that the completion dates stated were estimates, not guaranteed completion dates, provided to the Company by the contractor. (UGI Electric St. No. 3-R, p. 2, lines 21-23). The Penn Renewables' arrays are the first large-scale customer-generation sites to apply for connection to UGI Electric's

distribution system. Therefore, adequate time was required for UGI Electric to engage appropriate contractor resources and work to provide the necessary data for the required system models to be developed, which is an important piece of ensuring safe interconnection. As the Company gains more experience with these large-scale projects, efficiencies will be realized in the process, however, Penn Renewables cash flow concerns, while important, do not outweigh the need to provide safe and reliable service for all UGI Electric customers.

At no point has UGI Electric unnecessarily delayed on this effort. Initially, UGI Electric engaged a consultant to complete the required studies using engineering models provided by the Company. Subsequently, UGI Electric expanded the scope of work with its consultant to include the development of the engineering models, at UGI Electric's cost, to reduce the project timeline. UGI Electric has communicated with Penn Renewables throughout the process, including holding a scoping meeting. In addition, UGI held a meeting with Penn Renewables and the consultant to discuss how the study would be conducted. UGI Electric's decision to expand the scope of work with its consultant at an additional cost to the Company demonstrates the Company's commitment to these projects and the timeliness of providing results in support of a safely connected large-scale project. UGI Electric continues to work with the consultant to complete this effort.

Mr. Crist also misrepresented my testimony by implying that UGI Electric admitted that it "does not have expertise to evaluate and understand safe interconnection" (Penn Renewables, St. No. 1-SR, p. 23, lines 10 – 12). Again, Mr. Crist omits several key words from my statement: "…the Company does not maintain in-house expertise or the necessary engineering models to conduct the required analysis that is necessary to allow for the safe

interconnection of **these large-scale generation projects**." (UGI Electric St. No. 3-R, p. 2, lines 15-17). It is important to note the distinction that in-house expertise and the necessary engineering models are not maintained for large-scale solar generation projects, again, because projects of this size are new to the territory.

UGI Electric, in conjunction with PJM, has studied and successfully interconnected large traditional generation facilities to its transmission system. UGI Electric has also maintained a safe and reliable electric system for over 100 years. The interconnection of large solar installations to electric distribution systems, intended to serve as distributed generation resources, is relatively new to Pennsylvania and installations on the UGI Electric distribution system do not currently exceed 100kW. As a small electric utility, receipt of multiple applications submitted in a short period for solar generators in the 1MW to 2MW range required the development of a new process, utilization of engineering models and analysis tools that do not currently exist at UGI Electric, and the realization that internal experience with these large solar installations was limited. In addition, the proposed siting of these projects, all within the same general location on a single feeder, added a level of complexity and concern for existing customers and impacts to existing facilities as is the case with any distribution system. As a result, UGI Electric felt it was prudent and logical at this time to utilize a consultant that has experience with solar distribution interconnections to ensure a safe and reliable interconnection for both our customers and developers.

B. SUPPLY PEAK LOAD IMPACT ("SPLI")

Q. Mr. Crist provides numerous criticisms related to the Company's proposal to utilize supply peak load impact ("SPLI") as the determinant related to default service under GSR-1 (below 100kW SPLI) or GSR-2 (100kW and above SPLI). How do you respond?

A. Mr. Crist's concerns have been addressed at UGI Electric Rebuttal Statement No. 3-R, pages 4 – 6 and Mr. Faryniarz's rebuttal at UGI Electric Statement No 2-R, pages 18-21. However, I would like to reiterate that 52 Pa. Code § 54.2 defines "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 EDC tariff in a particular service territory** (emphasis added). The Company's proposal is simply asking for Commission approval of its definition of SPLI, as it is further defined in its proforma tariff and as is supported by testimony provided in this proceeding.

I also note that many of Mr. Crist's arguments relate to distribution rate concepts. UGI Electric's intent is to design default service rates that are fair, equitable and non-discriminatory to default service customers, especially residential and small business customers. The Company's distribution rates are also designed to comply with the requirement to provide least cost to customers over time. As explained in the rebuttal testimony of Mr. Faryniarz, (UGI Electric St. No. 2-R, p. 18-19), if these large customer generators are included in the GSR-1 rate, it will increase the risk to wholesale suppliers and increase bid premiums, which will result in discriminatory rates, as costs are shifted from the commercial generator cost causer to residential and small business customers. These customers will be required to pay increased prices to subsidize these large customer

generators. The increased bid premiums also will not create default service rates for residential and small business customers that are least cost over time.

C. GSR-2 RATE AND AEPS COMPLIANCE

Q. Mr. Crist provides numerous criticisms related to the calculation and application of the Company's GSR-2 rate when applied to customer-generators who are net metering, including how it does not appear to comport with legislative or regulatory requirements. How do you respond?

A. Mr. Crist avers several criticisms related to the GSR-2 rate, including:

1. The GSR-2 rate does not provide full retail value and is a wholesale rate (Penn Renewables St. No. 1-SR, p. 31.) and that UGI Electric is "cherry-picking" elements to be load-focused rather than supply-focused.
2. The GSR-2 rate does not provide a "kWh for kWh" crediting (Penn Renewables St. No. 1-SR, p. 30, line 6.) and customers participating in virtual net metering would not receive "kWh for kWh" crediting. (Penn Renewables St. No. 1-SR, p. 31-32.)
3. The GSR-2 rate is not a stable rate. (Penn Renewables St. No. 1-SR, p. 11.) UGI Electric does not treat line losses in accordance with AEPS. (Penn Renewables St. No. 1-SR, p. 5.) And the PTC-2 rate decreases as output increases (Penn Renewables St. No. 1-SR, p. 20).
4. The GSR-2 rate is not a "single rate option" as required by 52 Pa. Code 54.187(c). (Penn Renewables St. No. 1-SR, p. 29, lines 3-5)
5. The GSR-2 rate is not a default service rate (Penn Renewables St. No. 1-SR, p.28).

I will address why each of these concerns expressed by Mr. Crist are incorrect below:

1. *The GSR-2 rate does provide full retail value for net metering customers, including large-scale customer generators, such as Penn Renewables.* Mr. Crist's point has been addressed at length in UGI Electric Statement No. 3-R, p. 7-9. However, the Company would like to provide an illustrative example, attached as UGI Electric Exhibit TAH-2RJ, which was included in its response to Penn-III-6. As shown in the attached exhibit, all retail rate line items are included in the PTC for both GSR-1 and GSR-2 customers. These items are either supply-focused or load-focused based on how they are billed by PJM and directly relate to appropriate Company cost allocations for providing default service. Mr. Crist further argues that the GSR-2 rate is not a retail rate because it is based on a wholesale rate. Penn Renewables St. No. 1-SR, p. 2. This argument demonstrates a clear misunderstanding of wholesale and retail rates. All default service rates in Pennsylvania are based on wholesale rates as the underlying cost for energy. PJM costs, administrative costs and taxes are added to the wholesale power costs to develop the retail rate. Both GSR-1 and GSR-2 are retail rates based on one or more wholesale market products (load following, block, spot) and include appropriate recovery of all related PJM costs, Company administrative costs and taxes.

Further, the U.S. Energy Information Administration ("EIA") defines "Wholesale sales" as "Energy supplied to other electric utilities, cooperatives, municipals, and Federal and state electric agencies for resale to ultimate consumers." The EIA defines "Retail sales (electric)" as "Sales made directly to the customer that

consumes the electricity." Under the GSR-2 rate, UGI Electric is selling electricity to customers that consume the electricity. Therefore, the GSR-2 default service rate is clearly a retail rate and the hourly values under the GSR-2 pricing formula reflect the "retail value".

2. *The GSR-2 rate does provide a "kWh for kWh" crediting and virtual net metering participants would also receive a "kWh for kWh" crediting.* The Company is giving GSR-2 customer generators credit for all excess kWh as a function of the hour in which the excess generation occurs. The Company then nets such credit against any hours of net consumption in a manner which provides a full retail value to the customer generator. The approach permits detailed tracking and awareness of excess by converting those hours to a dollar value throughout the PJM year at the time it occurs rather than the end of the PJM year. Regarding Mr. Crist's concerns over virtual net metering, no large customer-generator, including Penn Renewables, has requested this service. However, if such a request were made, UGI Electric would aggregate production and net consumption for calculation at full retail value. The Company currently has a few virtual net metering customers for which it performs kWh netting.

3. *Mr. Crist's concerns with rate stability were addressed in UGI Electric St. No. 3-R, p. 9-10.* Additionally, the AEPS act does not require price stability. Also, in regard to line losses, as noted in the Rebuttal Testimony of Mr. Faryniarz, UGI Electric Statement No. 2-R, p. 28, lines 2-13, because of the nature of the proposed

PTC-2 calculation, customer-generators are compensated for line losses. In terms of the PTC-2 rate decreasing, the overall rate increases with more usage or generation due to recovery of fixed costs over greater kWh.

4. *The GSR-2 rate is a single rate option.* Mr. Crist's concerns with providing GSR-2 customers with a single rate option are addressed in UGI Electric St. No. 3-R, p. 10, lines 11-21. While individual hourly calculations comprise the GSR-2 rate, it is a single default service rate offering that has been applicable to UGI Electric's large default service customers since the Company's initial DSP I proceeding. As noted below, the Commission has repeatedly allowed and even required hourly priced default service for larger customers.

5. *The GSR-2 rate is a default service rate.* While this concern was addressed in UGI Electric St. No. 3-R, p. 9, lines 11-17, the Company would like to reiterate that numerous EDC's have hourly default service pricing models, which are LMP-based, to serve large customers. These Pennsylvania EDCs include PPL[1], Duquesne[2], PECO[3], and FirstEnergy[4].

I have been advised by Counsel that additional comments concerning the legality of UGI Electric's proposal and conformity with AEPS will be addressed in briefs.

[1] https://www.pplelectric.com/-/media/PPLElectric/At-Your-Service/Docs/General-Supplier-Reference-Information/2024/PTC-Rate-Calculator-Jun-1-2024--May-25-2025-LCI.ashx

[2] https://duquesnelight.com/docs/default-source/default-document-library/currenttariff_81_25.pdf (Rider 9, page 106)

[3] https://azure-na-assets.contentstack.com/v3/assets/blt1b5616c79bacadb4/blt9448ea371fcf175a/66d11c48d1edec8084049f86/Current_Elec_Tariff_Effective_Sept_1_2024.pdf?branch=prod_alias (Class 3/4, page 38)

[4] https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/PA/tariffs/fe-pa-retail-tariff.pdf (Hourly Pricing Default Service Rider, page 208)

D. DISTRIBUTION RATE CLASSES VS. GENERATION CUSTOMER THRESHOLDS

Q. Mr. Crist states that "the Public Utility Code requires that if a utility has more than a single rate class that might apply to a customer, that it must place the customer on the most beneficial rate to the customer if the customer chooses that rate". (Penn Renewables St. No. 1-SR, p. 23) and believes this requirement would allow Penn Renewables to select its generation class. How do you respond?

A. I believe Mr. Crist is confusing the Company's distribution rates with default service generation supply rates. UGI Electric has many distribution rate classes, including those for residential customers (Rate R), small commercial and industrial customers (Rate GS-1), large commercial and industrial customers (Rates GS-4, LP, HTP), along with various lighting and miscellaneous distribution classes. A customer is assigned to one of these distribution rate classes based on meeting the availability requirements as outlined in the tariff. For example, to be classified as a GS-1 customer, the customer must not qualify for residential service and must not have demand in excess of 5 kW. To qualify for service under GS-4, the customer must have a minimum demand of 5 kW. These distribution rate classes do not affect the generation customer threshold assignments in the Company's DSP V Plan. Under DSP V, customers will be classified based on their SPLI, not their distribution rate class. SPLI is clearly defined in the proforma tariff with those customers below 100kW SPLI being served on GSR-1 and those customers with SPLI of 100 kW and above served on GSR-2. For example, a customer receiving service under the GS-1 distribution rate can receive default service under either GSR-1 or GSR-2 and such determination is a function of the SPLI being above or below 100kW for such

customer. The scope of this proceeding is focused on the default service generation thresholds, not the distribution rate classes. The requirement that Mr. Crist cites is applicable to distribution rates and where a customer may qualify for more than one distribution rate. The Company does maintain a process to identify such customers and applies the most beneficial distribution rate. Moreover, utilities have flexibility to design both distribution and default service rates to ensure just and reasonable rates that are not unreasonably discriminatory. UGI Electric is designing the GSR-1 and GSR-2 rates based on supply peak load impact to mitigate disparate rate impacts for residential and small business customers.

E. CREDITING FOR PLC & NSPL-BASED CHARGES

Q. On p. 32 of his surrebuttal testimony, Mr. Crist states that if a customer generator is supplying at all hours of PLC and NSPL, there will be no credit for capacity and most transmission charges, therefore the customer generator is not being compensated at full retail value. What are your reactions?

A. The Company has further reviewed this issue and agrees to revise its GSR-2 rate formula to credit customer generators for their respective PLC and NSPL offsets. The Company has provided a revised tariff to implement this change as UGI Electric Exhibit TAH-3RJ. Additionally, a revised example calculation is provided as UGI Electric Exhibit TAH-1RJ.

F. WAIVER REQUEST

Q. In your rebuttal testimony, UGI Electric requested a waiver of the 25 kW peak load threshold in order for large customer generators to be classified as GSR-2 default service customers (UGI Electric Statement No. 3-R, p. 14). Is this the first time the Company has notified parties of its intent to ask for a waiver?

A. No. UGI Electric requested a similar waiver in its DSP V petition on page 32, items 93-95.

IV. RESPONSE TO OSBA'S CONCERN OVER APPLICATION OF WAIVER

Q. Please explain Mr. Ewen's concern with UGI Electric's request to waive the 25 kW peak threshold.

A. Mr. Ewen stated "Counsel has expressed concern that a waiver of the protections for customers with less than 25 kW registered peak load (52 Pa Code section 54.187(h) could allow the Company to place small business customers in GSR-1 on a variable rate at the Company's discretion." (OSBA Statement No. 1-SR, p. 4).

Q. Would you like to clarify UGI Electric's intent in requesting the waiver?

A. Yes, the Company can confirm that approval of the waiver would not give the Company the discretion to move non-residential GSR-1 customers into the GSR-2 class unless the customers qualify for the move based on their SPLI.

Q. Does this conclude your rejoinder testimony at this time?

A. Yes.

EXHIBIT TAH-1RJ

Question 2

Request:

In UGI's petition at pages 20-21, UGI claims that GSR-2 net metering customers will be paid the "price to compare applicable to GSR-2 customers." Explain in detail how the PTC will be calculated. Will this PTC be published on the UGI's website? Is it expected to be materially different from GSR-1 PTC?

Response:

Please see Attachment PENN-I-2 for an example PTC-2 calculation detail. The provided calculation shows two hours: one where a customer is net consuming and one where the customer is net generating. This example is for illustrative purposes and assumes an LMP value of $40/MWh. PJM charges that are allocated based on PLC values are assumed at zero, using the assumption that a larger customer generator will be net generated during the hourly periods which establish PLC values. PJM charges that are allocated based on NSPL values were calculated using the average per kW charges from the May 2024 billing month, with the assumption that a larger customer generator will have a net consumption for 50% of the hourly periods which establish NSPL values. A per kWh rate for PJM charges that are allocated based on kWh was calculated by dividing costs by sales for the May 2024 billing month. Finally, a per kWh rate for administrative & general (A&G) charges was calculated in the same manner.

As PTC-2 will be an hourly rate applicable to each specific GSR-2 customer, publishing a specified rate is not possible. UGI Electric does plan to include the following language on its website: "The Price to Compare for GSR-2 (PTC-2) shall include the GSR-2 rate and the State Tax Surcharge in Rider A."

Depending on the point(s) in time when compared, UGI Electric does anticipate that the GSR-2 PTC-2 will differ from GSR-1 PTC-1, either higher or lower.

Prepared by or under the supervision of: James M. Rouland

UGI UTILITIES, INC. – ELECTRIC DIVISION
GSR-2 CUSTOMER PRICE TO COMPARE EXAMPLE CALCULATION

Line #	Line Item Description	Example of Hour Net Consumption (kWh)	Example of Hour Net Generation (kWh)
1	kWh (metered value)	100	(1,000)
2	Applicable hourly EHV Loss percentage (from PJM)	0.6%	0.6%
3	Total loss percentage with inclusion of 6.5% UGI system loss (L2+6.5%)	7.1%	7.1%
4	Loss gross up factor (1-L3)	92.9%	92.9%
5	Grossed up kWh for losses (L1/L4)	108	(1,076)
6	Applicable hourly deration factor (from PJM)	3.9%	3.9%
7	Deration factor (1-L6)	96.1%	96.1%
8	kWh (with deration) (L5*L7)	103	(1,034)
9	LMP ($/MWh)	$ 40.0000	$ 40.0000
10	LMP ($/kWh) (L9/1000)	$ 0.0400	$ 0.0400
11	Total LMP charges (L8*L11)	$ 4.1378	$ (41.3778)
12	PJM allocated charges - PLC based ($/kW)	$ 0.2597	$ (2.5972)
13	PJM allocated charges - NSPL based ($/kW) /A	$ 0.6375	$ (6.3750)
14	PJM allocated charges/(credits) - kWh based ($/kWh)	$ (0.0076)	$ (0.0076)
15	Total PJM allocated charges/(credits) - kWh based (L8*L14)	$ (0.7862)	$ 7.8618
16	DSP A&G allocated costs - kWh based ($/kWh)	$ 0.0070	$ 0.0070
17	Total DSP A&G allocated costs - kWh based (L8*L16)	$ 0.7241	$ (7.2411)
18	Net Metering Purchase Reconciliation /B (charge/(credit)*L8) ($/kWh)	$ -	n/a
19	Total GSR-2 (L11+L12+L13+L15+L17+L18) excluding GRT	$ 4.9729	$ (49.7294)
20	Total GSR-2 charges including GRT (L19/(1-5.9%))	$ 5.2847	$ (52.8474)
21	STAS (currently 0%)	0.00%	0.00%
22	Total PTC-2 (L20*(1+L21))	$ 5.2847	$ (52.8474)
23	Unit PTC-2 (per kWh) (L22/L8)	$ 0.0511	$ 0.0511

/A - Assumes NSPL value of 50kW (net consumption on 50% of NSPL hours)

/B - Assumes no current reconciliation charges/(credits)

EXHIBIT TAH-2RJ

UGI UTILITIES, INC. – ELECTRIC DIVISION
GSR CUSTOMER PRICE TO COMPARE EXAMPLE CALCULATION

Line #	Line Item Description for GSR-2 Customer	Example of Hour Net Consumption (kWh)	Example of Hour Net Generation (kWh)	Line Item Description for GSR-1 Customer	Example of Monthly GSR-1 Customer (kWh)
1	kWh (metered value)	100	(1,000)		
2	Applicable hourly EHV Loss percentage (from PJM)	0.6%	0.6%		
3	Total loss percentage with inclusion of 6.5% UGI system loss (L2+6.5%)	7.1%	7.1%		
4	Loss gross up factor (1-L3)	92.9%	92.9%		
5	Grossed up kWh for losses (L1/L4)	108	(1,076)		
6	Applicable hourly deration factor (from PJM)	3.9%	3.9%		
7	Deration factor (1-L6)	96.1%	96.1%		
8	kWh (with deration) (L5*L7)	103	(1,034)		
9	LMP ($/MWh)	$ 40.0000	$ 40.0000		
10	LMP ($/kWh) (L9/1000)	$ 0.0400	$ 0.0400		
11	Total LMP charges (L8*L11)	$ 4.1378	$ (41.3778)	Projected LMP, Block and Load Following Costs ($/kWh) /D	$ 0.09260
12	PJM allocated charges - PLC based ($/kW) /A	$ -	$ -	PJM Allocated Charges - PLC Based ($/kWh) /E	$ 0.00105
13	PJM allocated charges - NSPL based ($/kW) /B	$ 0.6375	$ 0.6375	PJM Allocated Charges - NSPL Based ($/kWh) /E	$ 0.00513
14	PJM allocated charges/(credits) - kWh based ($/kWh)	$ (0.0076)	$ (0.0076)	PJM allocated charges/(credits) - kWh based ($/kWh) /E	$ (0.00227)
15	Total PJM allocated charges/(credits) - kWh based (L8*L14)	$ (0.7862)	$ 7.8618		
16	DSP A&G allocated costs - kWh based ($/kWh)	$ 0.0070	$ 0.0070	DSP A&G and AECC allocated costs - kWh based ($/kWh)	$ 0.00170
17	Total DSP A&G allocated costs - kWh based (L8*L16)	$ 0.7241	$ (7.2411)		
18	Net Metering Purchase Reconciliation /C (charge/(credit)*L8) ($/kWh)	$ -	n/a	E-Factor (ECA) ($/kWh)	$ 0.00083
19	Total GSR-2 (L11+L12+L13+L15+L17+L18) excluding GRT	$ 4.7132	$ (40.1197)	Total GSR-1 excluding GRT ($/kWh)	$ 0.09904
20	Total GSR-2 charges including GRT (L19/(1-5.9%))	$ 5.0087	$ (42.6351)	Total GSR-1 including GRT ($/kWh)	$ 0.10525
21	STAS (currently 0%)	0.00%	0.00%	STAS (currently 0%)	0.00%
22	Total PTC-2 (L20*(1+L21))	$ 5.0087	$ (42.6351)		
23	Unit PTC-2 (per kWh) (L22/L8)	$ 0.0484	$ 0.0412	Total PTC-1 (L20*(1+L21)) ($/kWh)	$ 0.10525

/A - Assumes PLC value of zero (net generation during all PLC hours)
/B - Assumes NSPL value of 50kW (net consumption on 50% of NSPL hours)
/C - Assumes no current reconciliation charges/(credits)

/D - Based on June 1, 2024 Quarterly GSR filing
/E - Excludes PJM allocations to load following supplier in Line 11
Note: all GSR-1 cost recovered on a per kWh basis

EXHIBIT TAH-3RJ

UGI UTILITIES, INC. – ELECTRIC DIVISION

ELECTRIC SERVICE TARIFF

RULES AND RATES
FOR ELECTRIC DISTRIBUTION SERVICE AND
CHOICE AGGREGATION SERVICE

in the following service territory:

LUZERNE COUNTY

City of Nanticoke, and Boroughs of Courtdale, Dallas, Edwardsville, Forty-Fort, Harvey's Lake, Kingston, Larksville, Luzerne, New Columbus, Plymouth, Pringle, Shickshinny, Sugar Notch, Swoyersville, Warrior Run, West Wyoming and Wyoming.

First Class Townships of Hanover and Newport, and Second Class Townships, of Conyngham, Dallas, Fairmount, Franklin, Hunlock, Huntington, Jackson, Kingston, Lake, Lehman, Plymouth, Ross and Union.

WYOMING COUNTY

Townships of Monroe and Noxen

Issued: Effective for Service Rendered on and after:

Issued by:
Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

THIS TARIFF MAKES CHANGES TO THE EXISTING RATES (PAGE 2).

LIST OF CHANGES MADE BY THIS SUPPLEMENT

(Page Numbers Refer to Official Tariff)

Pursuant to the Final Order entered _____ approving the Default Service Program at Docket No. _____, the following changes have been made to incorporate default service rules beginning June 1, 2025 along with calculated default generation supply service rates effective June 1, 2025:

Rules and Regulations – 17. Net Metering, Pages 30 – 32

- 17-a(3) – Removed rate schedule names for customer types.
- 17-a(4) – Removed outdated language requiring that customer-generators have independent load. Renumbered items 17-a(5)-(7) to 17-a(4)-(6).
- 17-c(1) – Added language to clarify the Price to Compare that will be used to calculate compensation owed to customer-generators and the timeframe used to define the calculation cycle. Also, added language to define the calculation for compensation to customer-generators served under GSR-2.
- 17-e & 17-f – Removed rate schedule names.
- 17-g – Added language to define the payment distribution timeline.

Rider B – Generation Supply Service Surcharge, Pages 39-41

- Dates have been revised to reflect the Default Service rules beginning June 1, 2025.
- Revised GSR assignment to be based on supply peak load impact and added definition of supply peak load impact.
- Revised timeframe of GSR classification to be determined annually.
- Revised rate calculation frequency from quarterly to semi-annually.
- Added interim filing language for GSR-1.
- Revised GSR-1 formula to include “F” – relative cost factor and added the definition.
- Deleted references to transmission revenue from the EC calculation definition and GSR-2 costs.
- Updated ECA, SEC, Sint language to align with proposed rate updates.
- Added Non-Residential GSR-1 Rate.
- Eliminated migration rider and reverse migration rider from GSR-1 and GSR-2 customers.
- Added formula to show calculation of GSR-2 rate. Added reconciling components to costs. Clarified allocation of HTC component of GSR-2 rate.
- Clarified definition of Price to Compare for GSR-1 customers. Added language to define Price to Compare for GSR-2 customers.
- Clarified information to be provided in annual reconciliation statement. Added an annual reconciliation for GSR-2 customers.

RULES AND REGULATIONS (continued)

17. NET METERING

17-a Applicability. This rule sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

(1) Customer-generators served under Rate Schedules R, GS-1, GS-4, GS-5, and LP who install a device or devices which are, in the Company's judgment, subject to Commission review a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system are eligible for net metering.

(2) This rule is available to installations where any portion of the electricity generated by the renewable energy generating system offsets part or all of the customer-generator's requirements for electricity.

(3) A renewable customer-generator, under this rule, is a non-utility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service ~~(Rate R)~~ or not larger than 3,000 kilowatts at other customer service locations ~~(Rate GS-1, GS-4, GS-5, and LP)~~, except for a Customer whose system is above 3 megawatts and up to 5 megawatts who may qualify its alternative energy system for customer-generator status if, as set forth in the Commission's regulations: (a) the Customer makes its system available to operate in parallel with the grid during grid emergencies; or (b) the Customer's system is located within a microgrid. **(C)** **(C)**

~~(4) To qualify for net metering, the customer-generator must, among other things, have electric load, independent of the alternative energy system, behind the meter and point of interconnection of the alternative energy system. To be independent of the alternative energy system, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system.~~ **(C)**

(4) Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. The net metering rules are not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

(5) Service is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

(6) Review and approval of all customer-generator applications and interconnections shall be in accordance with the Commission's regulations.

17-b Metering Provisions. A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. If the Customer agrees, a dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

(C) Indicates Change

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

(3) Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternate energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for the disposition of those credits.

(4) Virtual meter aggregation on properties owned or leased and operated by the same customer-generator shall be allowed for purposes of net metering. Virtual meter aggregation shall be limited to meters located on properties owned or leased and operated by the same customer-generator within two (2) miles of the boundaries of the customer-generator's property and within the Company's service territory. All service locations to be aggregated must be Company service location accounts held by the same individual or legal entity receiving retail electric service from the Company and have measurable load independent of any alternative energy system. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing their account on a virtual meter aggregation basis.

17-c Billing Provisions. The following billing provisions apply to customer-generators in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at full retail rate, consistent with Commission regulations. If a customer-generator supplies more electricity to the electric distribution system than the Company delivers 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-generator in subsequent billing periods shall continue to accumulate until the ~~end of the year.~~final billing period on or before the end of the PJM year (May of each year). At the end of each PJM year, the Company will 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 ~~Company's~~ Customer's applicable Price to Compare (PTC-1 or PTC-2). Applicable PTC-2 rates shall be applied to the respective hours of excess generation. ~~(PTC-1) rate for customers receiving default service on GSR-1.~~ The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule. **(C)** **(C)** **(C)** **(C)**

(C) Indicates Change

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

(3) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs must be stated in the service agreement between the customer-generator and the EGS. The Company shall credit customer-generators who are EGS customers for each kilowatt-hour of electricity produced at the Company's unbundled distribution kilowatt-hour rate. The distribution kilowatt-hour rate credit shall be applied monthly against kilowatt-hour distribution usage. If the customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in any billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's unbundled kilowatt-hour distribution usage in subsequent billing periods until the end of the year when all remaining unused kilowatt-hour distribution credits shall be zeroed-out. Distribution credits are not carried forward into the next year.

(4) 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. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by the same customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

17-d Application. Customer-generators seeking to receive service under the provisions of this rule must submit a written application to the Company demonstrating compliance with the net metering provisions and quantifying the total rated generating capacity of the customer-generator facility.

17-e Minimum Charge. The Minimum Charges under ~~Rate Schedule R, GS-1, GS-4, GS-5, and LP~~the applicable rate schedule apply for installations under the net metering rules. **(C)**

17-f Applicable Charges and Fees. Bills rendered by the Company under this rule shall be subject to charges and fees applicable to ~~Rate Schedules R, GS-1, GS-4, GS-5, and LP.~~the assigned rate schedule. **(C)**

17-g Payment distribution. Any remaining credit balance as of the end of the May billing period will be paid to the customer via check within 90 days of May 31. **(C)**

(C) Indicates Change

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE

Company will supply Default Generation Supply Service (GSS) to Customers in the Company's service territory not receiving service from an EGS. The rules and rates contained herein apply to service provided on and after June 1, ~~2021~~2025. **(C)**

For Customers served through the Company's GSS, a Generation Supply Rate (GSR) shall be applied to each kilowatt hour of energy used by the Customer. Separate GSRs shall be calculated ~~and apply to the rate schedules listed below~~and apply in accordance with the following:~~.~~ **(C)** **(C)**

GSR-1 shall apply to all residential customers as well as non-residential customers with a supply peak load impact less than 100 kW. **(C)**

GSR-2 shall apply to all non-residential customers with a supply peak load impact greater than or equal to 100 kW. **(C)**
~~GSR-1 shall apply to Rate Schedules R, GS-1, GS-5, FCP, BLR, OL, SOL, MHOL, LED-OL, SL, SSL, MHSL, LED-SL and LED-CO.~~
~~GSR-1 shall also apply to Rate Schedules GS-4 and LP where the Customer's annual peak load is less than 100 kW.~~
~~GSR-2 shall apply to Rate Schedules GS-4, LP, and HTP where the Customer's annual peak load is greater than or equal to 100 kW.~~

Supply peak load impact will be determined on 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. **(C)**

The supply peak load impact used to assign customers to the applicable GSR rate shall be the Customer's highest supply peak load impact (kW) in the most recent 12-month period ending September 30. ~~Customer's highest billing demand in the twelve-month period ending September 30, 2020 shall be the annual peak load determinant for purposes of applying the GSR.~~ For new Customers without a twelve-month billing history, the ~~billing demand~~ supply peak load impact shall be based on the Company's estimate using factors such as, but not limited to, similarly equipped buildings, 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. **(C)** **(C)**

The GSR-1 rate shall be calculated every ~~three~~ six months beginning June 1, ~~2021~~2025. The GSR-1 rate shall be filed with the Commission with at least thirty days' notice prior to each ~~three~~six-month period and shall be posted on the Company's website. If the GSR-1 calculation results in a change in rate that is less than 2%, the Company, in its sole discretion, may file with the Commission a GSR-1 rate that is unchanged from the prior period. Pursuant to 52 Pa. Code § 69.1809(c), the Company may propose an interim reconciliation prior to the next adjustment interval. The rate will be calculated as follows: **(C)** **(C)**

$$GSR\text{-}1 = (((EC*F)/SEC) + (ECA/SECA) + (Int/Sint)) * (1/(1-T)) \quad \textbf{(C)}$$

EC = Projected direct and indirect purchased power costs incurred by the Company to acquire electric supply for the GSR-1 group for the next ~~three-month~~computation period including, a load following service, wholesale energy costs, alternative energy credits, capacity costs, transmission costs, and all other PJM bill line item expenses/credits excluding network transmission service credits and firm point-to-point transmission service credits/expenses. EC also includes administrative costs, legal costs, taxes, net metering costs related to required excess power purchases at the PTC-1 rate, and any other applicable costs of providing default service for the GSR-1 group. ~~The estimated EC shall be reduced by the estimated transmission revenues to be collected in accordance with the applicable rate schedules included in the GSR-1 group.~~ **(C)** **(C)** **(C)**

(C) Indicates Change

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE (continued)

F = Relative Cost Factor, updated at the beginning of the plan period on June 1, 2025. However, should the supply load change by more than 50% during the course of the application period, the Company will update the relative cost factors. The Relative Cost Factor reflects the load shape of the residential and non-residential classes and is: **(C)**

Application Period	Residential	Non-Residential
June 1, 2025 – May 31, 2029	1.02	0.93

ECA = Net over or under collection of the EC defined above to be refunded/recovered and calculated across relative cost factors. The ECA will be reconciled ~~quarterly~~ based on actual EC revenues received and actual EC costs incurred for the ~~three~~six-month period ending two months prior to the filed GSR effective date. ~~Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-1 Customers shall be included in the ECA component of the GSR-1 beginning June 1, 2021. The over/under collection existing as of May 31, 2021 shall be allocated to GSR-1 and GSR-2 Customers based on the percentage of the actual sales during the period of the over/under collection attributed to those Customers classified as GSR-1 and GSR-2 as of June 1, 2021.~~ In the event the ECA would result in less than (or equal to) a five percent (5%) change in the average total Residential bill, the Company will refund/recover the balance over a ~~three~~six-month period. In the event the ECA would result in more than a five percent (5%) change in the average total Residential bill for default service, the Company will refund/recover the balance over a ~~six, nine, or~~ twelve-month period ~~(as determined by the Company)~~. **(C)** **(C)** **(C)**

Int = 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.

T = The Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates, expressed in decimal form.

SEC = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the next ~~three-month~~computation period, in kilowatt hours. **(C)**

SECA = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the refund/recover period, in kilowatt hours.

Sint = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the ~~twelve-month period beginning December 1~~next computation period, in kilowatt hours. **(C)**

The current GSR-1 rate (in ¢/kWh) is: **(C)**

Residential	Non-Residential
x.xx	x.xx

(C)

~~10.525 ¢/kWh~~

~~GSR-2 shall be calculated for each default service Customer in this group. Company shall bill each Customer on a calendar month based upon actual costs incurred to serve the Customer. The costs will be allocated as follows:~~ **(C)**

~~Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 Customer by multiplying the Customer's actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.~~

~~(~~**(C) Indicates Change**

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE (continued)

GSR-2 shall be calculated for each default service Customer in this group. Company shall bill each Customer on a calendar month based upon actual costs incurred to serve the Customer, along with a reconciliation mechanism. The costs will be allocated as follows: **(C)**

GSR-2 = (HEC + HPC + HTC) + ((HECA + HIN)/12) * (1/(1-T)) **(C)**

HEC = Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 Customer by multiplying the Customer's actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.

HPC = Other power costs incurred by the Company to acquire electric supply for the GSR-2 group for the month shall be allocated to each GSR-2 Customer based on metered sales. Other power costs include alternative energy credits and all PJM bill ~~line item~~line-item expenses/credits excluding the following: costs for capacity services, transmission services, network transmission service credits and firm point-to-point transmission service credits/expenses. Other costs included are administrative costs, net metering costs related to required excess power purchases pursuant to PTC-2, legal costs, taxes, and any other applicable costs of providing default service for the GSR-2 group. ~~The actual costs shall be reduced by the actual transmission revenues to be collected in accordance with the applicable rate schedules included in the GSR-2 group.~~ **(C)**

HTC = Cost for capacity and transmission services based on the PJM bill ~~line item~~line-item expenses/credits applicable to these services shall be allocated to each Customer in the GSR-2 group. The capacity costs shall include the PJM bill line items for locational reliability, capacity transfer rights, RPM auction, and capacity resource deficiency. The capacity costs shall be allocated to each Customer based on each Customer's peak load contribution (PLC). The transmission costs shall include the PJM bill line items for network integration transmission service charges, transmission enhancement service charges/credits, and non-firm point-to-point transmission service charges/credits. The transmission costs shall be allocated to each Customer based on each Customer's network service peak load value (NSPL). Any expense/credit line items added by PJM related to these services shall be allocated ~~based on the Customer's applicable PLC and NSPL~~ by dividing the total charges by the total net GSR-2 PLC and NSPL values in order to determine the per unit of PLC rate and per unit of NSPL rates that will be assessed. Customer-generators may have PLC and NSPL negative values related to PLC and NSPL hours indicating net generation to which rates shall be assessed. **(C)**

HECA = Net over or under collection of the HEC, HPC, and HTC as defined above to be refunded/recovered over a 12-month period beginning September. The HECA will be reconciled based on actual revenues received and actual costs incurred for the twelve-month period ending May 31 and will be amortized over 12-months beginning September. The HECA shall be allocated to each Customer based on each Customer's PLC. **(C)**

HIN = 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. The HIN will be amortized over 12-months beginning September and shall be allocated to each customer based on each Customer's PLC. **(C)**

~~Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-2 Customers that migrate from rate GSR-1 shall be refunded/recovered from those Customers directly over 12 billing periods beginning September 1, 2021. The over/under collection existing as of May 31, 2021 shall be allocated to GSR-1 and GSR-2 Customers based on the percentage of the actual sales during the period of the over/under collection attributed to those Customers classified as GSR-1 and GSR-2 as of June 1, 2021.~~

~~Customers who undergo reverse migration, switching from GSR-2 to GSR-1 during the DSP IV term, will be exempted from any over/under collections as reflected in the Company's E-factor (existing as of May 31, 2021) for a period of 12 months after returning to GSR-1.~~

T = All costs for GSR-2 Customers shall include the Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates.

Price to Compare: The Price~~-To-~~ to Compare ("PTC") for GSR-1 (PTC-1) shall include the ~~Energy Charge ("EC"), and the Energy Cost Adjustment ("ECA"), contained in this Tariff. The Price-To-Compare shall also include the~~GSR-1 rate and the State Tax Surcharge in Rider A. Separate PTC-1 rates will apply to residential and non-residential customers. ~~PTC is not applicable to GSR-2.~~The Price to Compare for GSR-2 (PTC-2) shall include the GSR-2 rate and the State Tax Surcharge in Rider A. **(C)**

Annual Reconciliation Statement: On June 30 of each year, the Company will file with the Commission, its Annual Reconciliation Statement for the GSR-1 (with the actual costs and revenue for both residential and non-residential customers aggregated) and GSR-2 rates, ~~for~~for the preceding 12 months ending May 31. **(C)**

(C) Indicates Change

Issued:	Effective for Service Rendered on and after

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029	:	Docket No. P-2024-3049343 C-2024-3049618

DIRECT TESTIMONY OF JAMES L. CRIST, P.E.
ON BEHALF OF
PENN RENEWABLES, LLC

Penn Renewables Statement No. 1
August 2, 2024

I. WITNESS QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS, AND ON WHOSE BEHALF, YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc. a consulting firm focused on regulatory and market issues. My business address is 4226 Yarmouth Drive, Suite 101, Allison Park, Pennsylvania 15101. I am presenting testimony on behalf of Penn Renewables ("Penn").

Q. DO YOU HAVE ANY QUALIFICATIONS OR OTHER SPECIALIZED KNOWLEDGE THAT WOULD ASSIST THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("COMMISSION") IN ITS DELIBERATIONS IN THIS CASE?

A. Yes. I have a B.S. in Chemical Engineering from Carnegie Mellon University and an M.B.A. from the University of Pittsburgh. Additionally, I am a Registered Professional Engineer in the Commonwealth of Pennsylvania. I have attached a copy of my CV and Regulatory Experience as **Exhibits JC-1** and **JC-2** respectively.

Q. BRIEFLY DESCRIBE YOUR RELEVANT BUSINESS QUALIFICATIONS.

A. I have run a consulting practice for the past 25 years focused on regulated and deregulated energy company strategy, market strategy, and regulatory issues. During 2004 and 2005, I undertook a consulting assignment as the Vice President of Consumer Markets for ACN Energy. ACN is a gas and electric marketer that is active in eight states. Prior to my consulting practice, I worked at three major energy companies for a total of 19 years. Most

recently I was Vice President of Marketing for Equitable Resources. In that function I was responsible for the development of the company's deregulated business strategy.

Prior to that I was Vice President of Marketing for Citizens Utilities, responsible for gas, electric, water and wastewater marketing activities in several service territories within the United States. The gas and electric utility operations were in Vermont, Louisiana, Arizona, Colorado, and Hawaii. Under my direction, Citizens initiated commercial and industrial transportation and supply services at its gas operation in Arizona. I also directed significant gas supply contracting activities with large industrial and commercial customers in Citizens' gas operation in Louisiana.

Before that, during 1988 through 1994, I was the Marketing Director at the Peoples Natural Gas Company where I was actively involved in many gas transportation programs as the company relaxed transportation requirements so that customers would have supply choices.

In summary, I have considerable experience in several states involving residential, commercial, and industrial customer energy procurement, regulatory issues and industry restructuring programs.

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

A. Yes, I have appeared before the Commission in numerous gas and electric regulatory proceedings. I presented testimony in Pennsylvania in recent cases involving the Philadelphia Gas Works, Columbia Gas of Pennsylvania, Duquesne Light Company, the Peoples Natural Gas Company, and First Energy. Additionally, I have provided testimony on a variety of

issues relating to energy procurement, industry restructuring, and demand response before regulatory Commissions in Arizona, Kentucky, Tennessee, Maryland, New Mexico, Illinois, Ohio, Wyoming, and the U.S. Virgin Islands.

II. PENN RENEWABLES

Q. WHAT IS PENN RENEWABLES?

A. Penn Renewables is a solar development company, founded in 2023 with the explicit goal of developing many small scale, distribution level solar arrays throughout the state of Pennsylvania. Penn Renewables' origin is rooted in its desire to meaningfully impact Pennsylvania's energy landscape – to create a nimble, small-scale company that educates landowners, democratizes accessible clean energy, and inspires a sustainable future. Founded by renewable energy veterans, Penn cultivates the untapped potential of distributed renewable energy and its power to embolden landowners across the state. The majority of Penn Renewables' support staff and contractors are located in Pennsylvania, or commute from New Jersey or Ohio.

Q. WHAT POWER GENERATION TECHNOLOGY DOES PENN RENEWABLES USE IN ITS PROJECTS?

A. Penn Renewables has only utilized solar photovoltaics.

Q. WHAT PROJECTS DOES PENN RENEWABLES HAVE?

A. Penn Renewables has over 300 solar arrays in development across the Commonwealth.

Q. WHAT UTILITY SERVICE TERRITORIES IS PENN RENEWABLES DEVELOPING GENERATION PROJECTS?

A. Penn is developing solar arrays in Pennsylvania Power and Light ("PPL"), Penn Power, Penelec, West Penn, Met Ed (collectively "FirstEnergy PA" or "FE PA") and UGI service territories.

Q. WHAT ARE THE SIZE RANGE OF PENN RENEWABLES PROJECTS?

A. All of Penn Renewables arrays are 1 to 2 MW in size.

Q. WHAT PROJECTS IS PENN RENEWABLES DEVELOPING IN UGI TERRITORY?

A. Penn Renewables has 12 arrays under development in UGI Electric's service area.

III. DEFAULT SERVICE

Q. WHAT IS DEFAULT SERVICE?

A. Default Service is a retail electricity supply option provided by a default service provider, which in Pennsylvania means the incumbent utility company. The option is available for customers who do not choose (contract with) an electric generation supplier ("EGS") under *Pennsylvania's Electricity Generation Customer Choice and Competition Act*, 66 Pa. C.S. § 2801, et seq., See 52 Pa. Code §§ 54.181-204. The rate for default service is known as the default service rate or more commonly as the Price to Compare ("PTC"). Because utilities are not permitted to earn a return (profit) on default service, because it is reconciled, the rate is intended to reflect the fully loaded cost of providing default service.

These costs include "generation, transmission and other default service cost elements, incurred in serving the average member of a customer class." (52 Pa. Code §54.187(e)). In short, every cost, whether a direct cost or allocated indirect cost, must be recovered in the rate. The rates are provided to the Commission for review prior to being put into effect, but the Commission review is geared toward process and not outcomes. In other words, the review is to make sure the Utility followed the procurement plan approved as part of its default service plan rather than the actual rates, because the intent is that the rate should reflect the market – within certain guardrails. (See 52 Pa. Code §54.188).

Q. WHAT IS A DEFAULT SERVICE PLAN?

A. Each electric utility subject to the Competition Act requirements must periodically submit to the Commission for approval, a default service plan that explains how it will procure the energy that it will use to provide default service. These plans typically include a schedule of auctions, the types of products that will be purchased, the bidding rules, etc. Once the plan is approved by the Commission, the utility is required to execute the plan as approved. Default Service is the default option for customers who either do not actively select a competitive electricity supplier or whose chosen supplier ceases to provide service. (52 Pa. Code §54.189).

Q. WHAT IS THE ALTERNATIVE ENERGY PORTFOLIO STANDARDS ACT?

A. The Pennsylvania Alternative Energy Portfolio Standards Act ("AEPS") (73 P.S. § 1648.1, *et seq*.), enacted in 2004 and amended in 2007, is legislation aimed at promoting the use of alternative energy sources within the Commonwealth. The key components and objectives

of the AEPS are: 1) it establishes threshold percentages of electric energy sold at retail that must come from identified renewable/alternative sources through the use of alternative energy credits ("AEC"); 2) it defines a new entity – a customer-generator – that is a customer that generates electricity for its own use; and, 3) it introduces the concept of net metering, which allows a customer-generator to deliver excess energy produced by its alternative energy generating system to the local electric distribution company and be compensated for any excess energy (production that exceeds consumption) at the end of each year.

In summary, the Alternative Energy Portfolio Standards Act is a legislative framework designed to increase the use of renewable and alternative energy sources within the Commonwealth, promoting environmental sustainability, economic growth, and energy diversity.

Q. WHAT IS A CUSTOMER-GENERATOR?

A. In the context of the Pennsylvania retail electricity market, a customer-generator refers to a customer who generates electricity on their own premises using eligible renewable energy resources. These customers participate in a program known as net metering, which allows them to offset their electricity usage with the energy they produce, kWh for kWh, and to be compensated for the excess at "full retail value". The Commission's regulations require that excess generation be netted out, on a per kilowatt hour basis against each kWh of consumption, at the full retail rate, including distribution. At the end of the annual billing period any remaining excess generation will be compensated at the PTC. (See 52 Pa. Code 75.13(e)).

IV. NET METERING

Q. WHAT IS NET METERING?

A. Net metering in Pennsylvania is a billing mechanism that allows residential and commercial customers who generate their own electricity from renewable resources to feed excess electricity back into the grid and to be compensated for the excess.

Q. WHAT ARE THE KEY ASPECTS OF NET METERING IN PENNSYLVANIA?

A. 1. Electricity Generation: Customers install renewable energy systems, such as solar panels, wind turbines, biomass, or other eligible technologies, on their property.

2. Grid Connection: These systems are connected to the local utility's distribution system. The electricity generated by the customer's system is first used to meet their own electricity needs.

3. Excess Electricity: When the renewable energy system generates more electricity than the customer consumes, the excess is sent to the grid.

4. Eligible Systems: Includes solar PV, wind, biomass, hydropower, and other renewable energy sources. Systems must meet specific technical and safety standards.

5. System Size Limits:

- Residential: Up to 50 kilowatts (kW).

- Non-Residential: Up to 3 megawatts (MW) or up to 5 MW for systems operating in parallel with the grid during emergencies.

6. Annual Reconciliation: If the customer generates more electricity than they consume over the course of a year, the utility compensates the customer for the excess at a rate based on the utility's periodic/fixed PTC.

7. Billing Period: Net metering consumption and production are netted monthly, and any excess generation is carried forward from month to month within the same year. At the end of the annual billing cycle, any remaining imbalance of production versus consumption is reconciled.

Q. WHAT ARE THE BENEFITS OF NET METERING?

A. Net metering in Pennsylvania allows customers to generate their own renewable electricity, contribute excess power to the grid, and be paid for the excess generation, fostering the growth of renewable energy and offering economic and environmental benefits. It is critical, however, when designing incentive programs to ensure that the systems can be built and run profitably. For example, the PJM queue system was decried for many years by many developers as an impossible and impractical option, even though the capacity needs of PJM continue to grow.

Q. WHAT BENEFITS WILL LOCAL GENERATION PROJECTS BRING TO UGI CUSTOMERS?

A. Local generation should reduce local LMP prices and PJM costs to all UGI customers. By reducing the load of the UGI utility at any of the PLC and NSPL hours, all UGI customers will pay lower transmission rates as well as lower energy supply costs. With less energy flowing to UGI, the amount of congestion and other kWh based PJM charges will also be

reduced. Furthermore, with lower loadings on the local transmission lines, it makes it less likely for them to be overloaded and reduces the likelihood of both spiking nodal basis, but also for failures due to overloading.

Behind-the-meter generation ("BTMG") can have several impacts on local PJM pricing, which is a key component of the electricity market operated by PJM Interconnection. PJM manages the transmission grid and operates wholesale electricity markets in the Mid-Atlantic region of the United States. Behind-the-meter generation might influence local PJM pricing in several ways:

1. Reduced Grid Demand

   Lower Consumption: When customers generate their own electricity behind the meter, their demand for electricity from the grid decreases. This reduction in grid demand can influence local and regional electricity prices.

   Decreased Market Prices: Lower demand for grid electricity can lead to decreased wholesale market prices, especially during periods of high local generation. If local generation reduces the need for more expensive peaking power plants, overall market prices in that area can decrease.

2. Reduced Need for Transmission, and delaying or delaying the need for transmission upgrades:

   Transmission Congestion: Behind-the-meter generation reduces the amount of electricity that needs to be transmitted from central generation sources to end-users. This reduction can alleviate transmission congestion, potentially lowering transmission congestion charges that contribute to overall pricing.

Congestion Costs: In areas with significant behind-the-meter generation, congestion costs might decrease, which can also affect the LMPs in that region.

3. Impact on Capacity Market Prices:

Capacity Needs: BTMG can influence the demand for capacity resources in the PJM Capacity Market. If BTMG reduces peak demand, it can affect the need for new capacity investments or the prices in the capacity market. In PJM's most recent capacity auction, for the majority of the PJM region including UGI, capacity prices for the 2025/26 delivery year soared to $269.92/MW-day, up from $28.92/MW-day in the last auction. This is a clear market signal that more generation is needed in PJM, including UGI's territory. Adding clean generation in UGI's territory is an excellent way to put downward pressure on prices.

4. Market Participation and Settlement:

Settlement Adjustments: While behind-the-meter generation typically does not participate directly in PJM's wholesale markets, its impact on demand and pricing can influence how settlements are calculated for utilities and market participants.

5. Price Signals and Incentives:

Investment Decisions: Changes in local pricing due to behind-the-meter generation can influence investment decisions and market behavior. For example, if BTMG lowers local prices significantly, it may affect the economics of additional generation investments or demand response initiatives.

In Summary Behind-the-meter generation impacts local PJM pricing primarily by reducing grid demand, influencing Locational Marginal Prices (LMPs), and potentially affecting capacity market prices. The presence of significant behind-the-meter generation

can lead to lower local prices due to decreased demand and reduced need for transmission and peaking resources.

V. ALTERNATIVE RESOURCE DEVELOPMENT AT UGI

Q. WHAT PORTION OF ENERGY SUPPLY MUST UGI OBTAIN FROM ALTERNATIVE ENERGY RESOURCES?

A. Under Pennsylvania's AEPS, UGI Utilities, Inc. ("UGI") and other electric distribution companies ("EDC"s) and electric generation suppliers ("EGS"s) are required to obtain a specific portion of their energy supply from alternative energy resources. The AEPS mandates a gradual increase in the use of alternative energy over time. The key requirements are:

1. Tier I Resources: Includes renewable resources such as solar photovoltaic (PV), wind, low-impact hydropower, geothermal, biomass, biologically derived methane gas, fuel cells, and coal mine methane.

Compliance Targets: UGI must ensure that a certain percentage of their electricity supply comes from Tier I resources. As of the most recent updates, this percentage increases each year until it reached its peak of 8% in 2021.

2. Solar Photovoltaic (PV) Carve-Out: A subset of Tier I, specifically requiring solar PV energy.

Compliance Targets: UGI must obtain a specific portion of their Tier I requirement from solar PV. The solar carve-out percentage also increases over time and reached its present maximum of 0.5% also in 2021.

3. Tier II Resources: Includes waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, and wood pulping and manufacturing by-products.

Compliance Targets: UGI must ensure that a certain percentage of their electricity supply comes from Tier II resources. The requirement for Tier II resources remains at 10%.

Q. WHAT IS THE CURRENT STATUS AT UGI?A. UGI has been compliant with the requirements. Merely complying with regulatory requirements does not satisfy the projected needs for new capacity in the region; capacity that customer-generators would help provide.

Q. HOW MANY CUSTOMER-GENERATOR PROJECTS ARE THERE IN UGI'S SERVICE TERRITORY?

A. Presently there are no net metered projects 1 MW or larger on the UGI system. There are 30 projects under development, 16 of which are larger than 1 MW. (UGI St. No. 2, 26:16-27:11).

Q. WHAT PORTION OF UGI'S ENERGY NEED IS CURRENTLY SUPPLIED BY CUSTOMER-GENERATORS?

A. The alternative energy systems that are on the UGI system generate about 215,710 kWh. The fourteen projects that are up to 2 MW will provide as much as 22 MW of electricity if each system operates at maximum capability simultaneously. The total annual kWh

expected to be produced by these systems, if all are constructed and go into operation, is approximately 6% percent of UGI's total annual load.

Q. WHAT IS UGI DOING TO ASSIST CUSTOMER-GENERATORS IN DEVELOPMENT OF PROJECTS?

A. UGI has generally complied with the regulations on approving projects, but the timelines most certainly have not complied. Penn Renewables' first projects were approved by the state PUC on February 13th, 2024. System Impact Studies are generally due within 90 to 120 business days. UGI negotiated with Penn Renewables for an outside firm to perform the studies, which Penn Renewables requested in writing to move forward with on April 16th, 2024. It is Penn Renewables' understanding that these studies have not yet started. Penn Renewables was last notified of the status on June 12th, 2024, with no estimated time for completion provided. It has taken many more than are reasonable to process applications and facilities studies.

VII. PRICING

Q. WHAT DOES THE AEPS SPECIFY AS THE VALUE OF ENERGY PRODUCED BY NET METERED CUSTOMER-GENERATORS?

A. Section 75.13(f) of the PA Code outlines the billing and payment standards for net metering. It specifies that customer-generators should be credited at the full retail value on a kWh basis for the electricity they produce and feed into the grid up to the point where all consumption is netted annually, and thereafter, at the utility's periodic PTC for "excess"

generation. The Commission's Regulation modifies the statute and requires that customer-generators be compensated for excess generation at the price to compare.

Q. WHAT IS THE SUMMARY OF THE COMPENSATION MECHANISM MANDATED BY THE AEPS?

A. During the billing period the customer-generator will consume electricity they generate, offsetting purchases from the utility. Any excess generation is credited on a kWh for kWh basis on their utility bill. At the end of the billing period credits for each kWh of excess generation are carried forward to the next billing period within the same year. At the annual reconciliation, any remaining kWh at the end of the year are compensated for at the utility's periodic PTC.

Q. WHAT IS AN EXAMPLE OF THE COMPENSATION MECHANISM?

A. For example, if a customer-generator produces 1,000 kWh and consumes 800 kWh in a billing month, they will have a net excess of 200 kWh. The utility will credit the customer for 200 kWh at the full retail rate. At the end of year, if the customer still has a credit balance of 100 kWh at the end of the annual billing cycle, the utility will pay the customer for this excess at the PTC, not the full retail rate.

Q. HOW DOES THE FULL RETAIL RATE DIFFER FROM THE PTC?

A. The full retail rate includes charges for generation, transmission, and delivery or distribution, and surcharges for approved utility programs. The PTC is only the generation and transmission components, and therefore is a lessor amount than the full retail value.

Q. WHAT IS UGI'S RETAIL RATE?

A. For GSR-1, residential and non-residential, the current PTC is 10.525 cents per kWh.

Q. WHAT IS UGI'S WHOLESALE RATE?

A. UGI's wholesale rate is not transparent. It is not forecasted or reported by the Company, as its purchases include load following and block components. Overall, the wholesale rate is less than the retail rate. This can be observed by the historical records supplied by UGI for the GSR-1 retail rate and GSR-2 "wholesale passthrough" rate. For the period June, 2021, through June, 2024, there were only six months out of 37 months that the GSR-2 rate exceeded the GSR-1 rate. I include the response to Penn III-14 as **Exhibit JC-3**.

Q. WHAT ARE THE DIFFERENT COMPONENTS CONTAINED IN A RETAIL RATE THAT ARE NOT INCLUDED IN A WHOLESALE RATE?

A. Retail rates and wholesale rates for energy typically have different components due to their distinct purposes and the different costs they cover. A breakdown of the components often found in retail rates include:

1. Energy Supply Cost:

   - Generation Cost: The cost of generating the electricity.

   - Transmission Cost: The cost of transporting energy from power plants to local distribution networks.

   - Distribution Cost: The cost of delivering energy to end-users through local distribution networks.

2. Customer Charges:

- Fixed Charges: These are monthly fees that cover the costs associated with maintaining customer accounts and infrastructure, regardless of the amount of energy used.

- Service Fees: Fees for customer service, billing, and administration.

3. Demand Charges:

- For some customers, especially large commercial and industrial ones, there are charges based on their peak demand during specific periods, especially with "wholesales pass-through" tariffs rather than retail rates.

4. Capacity Charges:

- These cover the costs of ensuring there is enough capacity to meet peak demand, including investments in infrastructure and generation capacity.

5. Regulatory and Policy Costs:

- Environmental Compliance Costs: Costs related to meeting environmental regulations and sustainability initiatives.

- Public Policy Programs: Costs associated with supporting renewable energy programs, energy efficiency initiatives, and other state or federal mandates.

6. Energy Efficiency Programs:

- Costs associated with programs designed to help customers reduce their energy usage and improve energy efficiency.

7. Taxes and Fees:

- Various local, state, and federal taxes and fees that are applied to the retail energy price.

Q. WHAT ARE THE COMPONENTS CONTAINED IN A WHOLESALE RATE?

A. 1. Generation Cost: The primary component of wholesale rates, reflecting the cost of producing electricity.

2. Market Risk Premiums: Reflects the risks associated with energy market fluctuations.

3. Capacity Costs: Often included in wholesale rates to ensure sufficient generation capacity is available.

Wholesale rates do not typically include customer service charges, transmission or distribution costs, or various regulatory and policy costs that are part of retail rates. These additional costs are usually passed on to retail customers through their utility's retail rate structure.

Q. WHAT IS LOCATIONAL MARGINAL PRICE?

A. The Locational Marginal Price ("LMP") is a pricing method used in the electricity markets to reflect the cost of supplying the next increment of electricity at a specific location, considering the demand and the transmission constraints. LMPs vary by location and time and are determined by the cost of producing the next megawatt-hour (MWh) of electricity by the most economical generator available. Physical limitations on the transmission network that can lead to congestion, which affects the ability to deliver electricity from cheaper sources to where it is needed. Also included in the LMP are the real power losses that occur as electricity travels over transmission lines.

VIII. UGI ISSUES

Q. WHAT DOES UGI'S DSP V PROPOSE TO PAY FOR ENERGY PRODUCED BY CUSTOMER-GENERATORS?

A. UGI's Default Service Provider V ("DSP V") refers to the rate structure and policies UGI Utilities uses for default service, and includes terms related to customer-generated energy, such as those from solar panels or wind turbines.

UGI is proposing to follow the general structure of the AEPS requirement that energy produced by a customer-generator via net metering is credited at the full retail rate up to the point where production exceeds consumption. This netting will take place every month. It appears, however, that rather than carry forward kWh of excess generation, that UGI is planning to determine the value at the end of each billing period and carry forward that amount.

What that means is that at the end of the year, there will be no compensation at the PTC for all excess kWh credits. Rather, UGI will simply add the monthly value amounts to determine how much to compensate the customer-generator. The reason for this modification is that there is no default service rate. UGI has instead proposed GSR-2 customers, which includes Penn, will be netted hourly and excess generation will be calculated hourly and compensated not at some known rate, but rather at the PJM wholesale rate for that particular node known as the Locational Marginal Price or LMP, for that particular hour. What this means is if the LMP is at $100/MWh for a single hour, the excess generation is compensated for at that $100 per MWh rate. But it also means that if the LMP is minus $100/MWh for that hour, the customer-generator will be debited, not credited at a rate of $100/MWh. In other words, for certain hours, a customer-generator

could be paying to produce energy that its neighbors are using, but for which they are certainly not paying a negative rate to UGI. UGI has proposed to include some of the cost recovery that is typical for PTCs, but it is not clear from discovery whether all of those rate elements will be recovered. It is clear, however, that the rate that UGI will charge to non-customer-generator customers in the GSR-2 procurement class will not be the same, in any particular hour, as the rate of compensation that will be paid to customer-generators for excess generation produced in that same hour. I include the response to Penn I-2 as **Exhibit JC-4**.

Q. WHAT IS UGI REQUIRED TO PAY FOR ENERGY PRODUCED BY CUSTOMER-GENERATORS

A. The AEPS Act requires that "excess generation from net-metered customer-generators shall receive full retail value for all energy produced on annual basis." The Commission's regulations have scaled that back a bit and require that net-metered customer-generators receive the full retail value up to the point production nets consumption. After that point, all excess generation is compensated at the utility's PTC.

Q. WHAT EXACTLY HAS UGI PROPOSED?

A. For customer-generators with less than 100 kW of system impact, nothing will change. They will be classified as GSR-1 and will continue to net meter and receive the residential/small commercial PTC for excess generation. However, for customers and customer-generators with greater than 100 kW of supply peak load impact, classified as GSR-2, things will change. GSR-2 customers will be placed on a mandatory variable rate

that will not include the same cost recovery as GSR-1, and which will largely reflect the PJM LMP for the pricing node that applies to UGI.

Q. WHAT IS SUPPLY PEAK LOAD IMPACT?

A. This is a component in UGI's determination of the rate proposed for GSR-2 customers. According to UGI, Supply Peak Load impact is not the same as peak load, rather it is determined on the net demand contribution impact to the Company's default service procurement activity and is determined based upon net power flow from or into UGI's distribution system. Stated differently, UGI has created a "procurement class" based upon the customer's peak system impact, not their load.

Q. DOES ANY OTHER UTILITY USE SUCH A METHODOLOGY?

A. No. This methodology is essentially using the maximum of either customer demand or supply as a basis for segregating customers into separate tariffs. Setting distribution rates based on demand is fairly normal, but I am not aware of any electric utilities in Pennsylvania using peak supply to establish commodity rates that are paid to customer-generators. UGI should not be permitted to do so.

Q. WHY IS THIS METHODOLOGY A CONCERN?

A. There are a number of reasons. First, the rate is structured if a customer-generator produces excess generation, which reduces the amount of generation UGI must purchase from PJM to satisfy other customers' needs, UGI lowers the compensation for that generation. UGI's pricing formula for the net metered compensation is based on the PJM nodal price and that

price reduces when there is increased self-generation on the system and if the generator has any NSPL based demand allocations. Therefore, when producing power for export, the price received by the GSR-2 customer-generator will decrease and they will earn less. The UGI customer-generators that are GSR-1 customers will be charged a much higher rate for their power needs that are not met by their own generation. At these times when the customer-generator is a net exporter of energy, other GSR-2 customers will also benefit, because as the nodal LMP falls, their effective electricity rate also decreases. Based on discovery responses, it is clear that customers classified as GSR-2 will pay more than the amount that net metered customer-generators will be paid for excess generation, for the same hour. (Exhibit JC-4)

Q. DOES UGI'S PROPOSED TARIFF COMPLY WITH AEPS?

A. No. UGI's proposal fails to compensate net metered customer-generators at the full retail value of the energy they produce. First, the pricing structure is not based on UGI's cost to provide retail service, it is based on the sales price for the excess energy in the wholesale market. UGI has admitted that there may be times that the wholesale price of the energy is zero or less, that in effect during some periods the customer-generators could be paying to generate electricity that is being used to serve their neighbors who will not be paying zero or less for that energy. (Exhibit JC-4). The UGI plan treats net metered customer-generators as though they were wholesale generators, and the compensation structure belies that notion.

Another serious flaw in UGI's plan are adjustments UGI makes to the full retail value. I am advised by counsel that the AEPS requires that customer generators "shall receive full

retail value for all energy produced on an annual basis." Apart from the flawed pricing mechanism that treats net metered customer generators as wholesale sellers, it also purports to apply multiple "adjustments" to the energy that is metered at the customer generator's site as it enters UGI's system. There should be no loss factors applied to that energy, rather compensation, as required by the law, should be for all energy. Physics make it clear that the vast majority of that energy will be consumed by customers on the UGI distribution system and will not flow to PJM. (See **Exhibit JC-5**, which is UGI Response to Set II-1). Even if it were exported to PJM, the law requires compensation for all of the energy, not energy reduced by loss factors and other adjustments

Q. ARE THERE ADDITIONAL COMPONENTS OF UGI'S PLAN THAT VIOLATE THE LAW?

A. Yes, for example, I am advised by counsel that Act 129 requires that the electric power used for default service "be procured through a competitive procurement process" and shall include: auctions, requests for proposals or bilateral agreements. (66 Pa. C.S. § 2807(e)(3.1). There is no provision in the purchase plan for GSR-2 customers that includes auctions, RFPs or bilateral contracts. Rather, the rate will be a modified version of PJM hourly wholesale price and it will not be a voluntary contract on the part of customer-generators. I am also advised by counsel that Act 129 also requires that small business customers be provided a rate that changes no more often than quarterly.[1] While the term small business customer is not defined in the statute, it is defined in the Commission's regulations as a "person, sole proprietorship, partnership, corporation, association or other

[1] 66 Pa C.S. § 2807(e)(7)

business entity that receives electric service under a small commercial, small industrial or small business rate classification and whose maximum registered peak load is less than 25 kW within the last 12 months." 52 Pa. Code § 54.2. This regulation points out another flaw in UGI's plan that requires correction. Its tariff supplement purports to aggregate customer-generators based on system impact as GSR-2 customers. But the small business definition uses registered peak load, which is not the same thing. Penn, in particular, is confident that most, if not all of its systems will have less than 25 kW of peak load which means that they will qualify as small business customers. UGI does not explain how its plan will be implemented so as not to violate the statute While I would expect that most of the non-generating customers in GSR-2 might have peak load over 25 kW, for commercial customer-generators, that is not universally true.

Q. WHAT OTHER ASPECTS OF UGI'S PROPOSED RATE STRUCTURE ARE PROBLEMATIC?

A. The UGI plan appears to be expressly intended to discourage commercial scale customer-generators from developing projects in the UGI territory. If such projects are built and connected, they will provide benefits to the other customers on the system, yet the customer-generator will not receive compensation for those benefits, under UGI's scheme. Such benefits include providing generation that supports reliability, particularly in isolated geographic areas, that can reduce the need to purchase energy from other sellers, which in turn can help to reduce costs for all customers. Instead of compensating these nascent resources for the benefits they provide, UGI appears instead try to keep them from developing on its system. In one particularly twisted disincentive of this proposed

methodology, customer-generators do not receive compensation for production during PJM's PLC or NSPL hours, when UGI customers have many of their annual PJM charges set. In UGI's proposed mechanism, supplied kW are not treated as "negative" like kWh, instead the PLC or NSPL allocation is marked as zero. A customer-generator supplying power during these PJM bill setting hours will put downward pressure on costs to all other UGI customers as the PJM PLC and NSPL demand-based charges that are allocated to other UGI customers will be lower. If UGI did treat supply during PLC or NSPL hours as "negative demand", it would have the impact under this proposed methodology, of lowering the rate charged to a customer-generator for load, and increasing the refund rate paid when a customer-generator supplies excess power.

Q. DO PENNSYLVANIA'S NET METERING REGULATIONS MANDATE PAYMENTS BASED ON ENERGY OR DEMAND?

A. In Pennsylvania, net metered customers are not charged per kilowatt (kW) for their power directly. Instead, the AEPS mandates that they be billed/compensated based on their net energy usage or production (kWh).

Q. WHAT UTILITIES ARE USING A NET SUPPLY IMPACT CONSTRUCT IN THEIR PRICING MODEL?

A. No other utility in Pennsylvania uses a net supply impact metric.

Q. HOW DOES UGI'S PRICING VARY DEPENDING ON THE POSITION OF THE CUSTOMER-GENERATOR?

A. For a given LMP, if the customer-generator has any demand related charges allocated (PLC or NSPL), the "refund" rate will be lower than the rate charged to other GSR-2 customers when the customer-generator is supplying excess power. This is not fair to the customer-generator.

Q. DOES UGI PROPOSE TO RECONCILE THE RATES CHARGED/PAID TO CUSTOMER-GENERATORS?

A. No.

Q. IS THE GSR-2 RATE STRUCTURE A "SINGLE RATE OPTION" AS DESCRIBED IN THE COMMISSION'S REGULATIONS AT 52 PA CODE §54.187(C)?

A. No. There is effectively no fixed GSR-2 rate. Customer- generators will be charged some amalgamation of charges that do not include all cost elements identified by the Commission as being required to be recovered in the PTC. (See 52 Pa Code §69.1808). Also, the rate will change hourly, hence is variable and therefore is not a fixed single rate option.

Q. DOES THIS RATE COMPLY WITH THE REQUIREMENT (52 PA. CODE § 54.187(D) THAT RATES NOT DECLINE WITH AN INCREASE IN ELECTRICITY CONSUMPTION?

A. No. The Code states, "(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." UGI's proposed mechanism does not comply, as it is clear that the rate that charged to non-generating customers, will decrease as consumption increases. I include the response to Penn III-8 as **Exhibit JC-6**.

Q. THE COMMISSION'S REGULATIONS REQUIRE THAT THE PTC BE DESIGNED TO RECOVER ALL DEFAULT SERVICE COSTS OF THE "AVERAGE MEMBER OF A CUSTOMER RATE CLASS" DOES THE UGI PROPOSAL COMPLY WITH THAT REQUIREMENT?

A. No. The GSR-2 rate PTC will be different for each customer on the rate and for each hour the customer is on that rate. The rate will be based on the PJM locational marginal price (LMP) and also will vary by other characteristics such as demand/supply at the five PJM determined PLC hours and five PJM determined NSPL hours. Higher allocations of these types of allocated charges can push the GSR-2 rate to significantly below the LMP price at lower levels of generation from the customer-generator (UGI response to Penn I-2) UGI's responses to the interrogatories demonstrates this very well. A customer consuming energy will pay a different rate, in the same hour, than a customer generating energy. There is no average customer, they are all unique.

PJM's coincident Peak Load Charges (PLC based) are based on the five highest peak demand hours across the entire PJM region during the year. These hours are typically times of highest electricity usage, often occurring when heating or cooling demand is at its peak. Historically, these PLC days have taken place during the summer months of June through September, months when solar production is at its highest.

PJM's Network Service Peak Load charges (NSPL based) are based on the five highest most transmission constrained hours across the entire PJM region during the year. These also historically occur during solar operational hours, usually in winter or late summer.

Q. ARE THE COSTS OF REIMBURSING CUSTOMER-GENERATORS A COST OF COMPLIANCE WITH THE ALTERNATIVE ENERGY PORTFOLIO STANDARDS ACT?

A. I am advised by counsel that the Act requires utilities to compensate net-metered customer-generators for all excess generation. Such payments are a cost of compliance.

Q. IS "REGISTERED PEAK DEMAND" OR "PEAK LOAD" THE SAME AS "SUPPLY PEAK LOAD IMPACT"?

A. No. See UGI response to Penn I-1 which I include as **Exhibit JC-7**. UGI's newly invented term "supply peak load impact" addresses "system impact" as determined by UGI, but is not equal to the peak load a customer is experiencing.

Q. DO COMMERCIAL NET METERING SOLAR FACILITIES SUCH AS THOSE THAT ARE PLANNED BY PENN CONSUME MUCH ENERGY?

A. No. Penn's best estimate is that majority of their installations in the UGI territory will use less than 20 kW of power. This demand is from when the systems are not in operation, and

comes from running the power supply of the inverters, monitoring and data acquisition systems, metering systems, and security systems of the solar facilities.

Q. WHAT CHANGES TO UGI'S PROPOSED TARIFF ARE NEEDED TO COMPLY WITH THE AEPS?

A. The tariff concept of a mandatory LMP-based variable rate for a rate class that includes some larger customers and all commercial scale customer-generators over 100 kW system impact must be changed to being voluntary and an alternative fixed rate based on the actual cost of providing a fixed rate should be offered. Businesses that will be forced onto a variable rate as volatile as the PJM LMP will not be pleased with volatility of such a rate and would be eager to have a fixed rate option. Businesses require stability and UGI's plan does not provide that.

Q. WHAT IF THE COMMISSION CONCLUDES THAT A VOLATILE VARIABLE RATE IS ACCEPTABLE; WHAT CHANGES WOULD YOU THEN RECOMMEND?

A. If the Commission wishes to permit UGI to offer a volatile variable rate to GSR-2 customer-generators then increase the threshold from 100 kW to 3 MW, in line with the AEPS. If UGI is not providing the benefit of certainty to GSR-2 customer-generators then such uncertainty should be offset by providing a price premium as an adder to the volatile price that customer-generator will be paid by UGI. This adder should be equal in magnitude

to the premium UGI is paying for price fixing their supply (i.e. load following premium and other related costs).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT JC-1

JAMES L. CRIST

PRESIDENT, LUMEN GROUP, INC.

Suite 101, 4226 Yarmouth Drive ● Allison Park, PA 15101

Phone: 412.487.9708 ● Cell: 412.613.8886 ● E-mail: JLCrist@aol.com

DEMONSTRATED AREAS OF EXPERTISE

¨ GENERAL MANAGEMENT	Proven executive-level management expertise with excellent capabilities in developing, implementing, and supervising corporate-wide policies and procedures in areas including sales, marketing, customer service, public relations, rates, regulatory affairs, and administration. Possess a unique combination of abilities to set goals, develop winning business strategies, organize structures and work methods, and train the right people for the right positions to make it all work. Skilled in strategic short and long-term planning and budgeting with effective abilities in reducing the "fat" and increasing organizational efficiency. A creative, decisive leader who can successfully meet challenges and overcome obstacles to achieve profit objectives.
¨ REGULATORY STRATEGY	A thorough strategist with an extensive background in utility business unit operation (electric, natural gas, water/wastewater) the full range of rate and regulatory functions, from tariff development and special contract negotiation. Proven personal testifying skills with an outstanding record of developing and presenting successful written and oral testimony, along with settlement negotiations.
¨ PERSONNEL MANAGEMENT	Effective interpersonal communications skills support outstanding capabilities in recruiting, training, motivating, and directing staff at all levels. Proven ability to build productive, highly motivated teams of sales/marketing, operations, technical, and customer service personnel who contribute to top organizational performance.
¨ PERSONAL ATTRIBUTES	A determined, hardworking, challenge-driven executive with the skills and experience to bring excellence to any business organization. A high-energy mover and shaper ... experienced in successful start-ups and turn-arounds. An excellent communicator - written and verbal. A frequent speaker at professional symposiums, able to interpret and communicate complex concepts for diverse audiences. An engineering/technical specialist and a management generalist. Active in civic and community affairs.

EMPLOYMENT HISTORY

LUMEN GROUP, INC., Pittsburgh, PA — 1996 - Present

President - A consulting practice specializing in strategic planning, business planning, regulatory strategy, marketing and venture development in the electric, natural gas and energy services industries. Please see Addendum for amplification of consulting assignments.

ACN ENERGY, Farmington Hills, MI — 2004-2005

Vice President, Consumer Markets

OPTIRON, Pittsburgh, PA — 2003-2004

Vice President, Marketing

E R I SERVICES, Pittsburgh, PA — 1996

Vice President, Marketing & Product Development

CITIZENS UTILITIES, Harvey, LA & Stamford, CT — 1994 - 1995

Vice President, Marketing

CONSOLIDATED NATURAL GAS, Pittsburgh, PA — 1977 - 1994

Director, Residential & Commercial Marketing (1988 - 1994)
Manager, Technical Sales/Market Development (1985 - 1988)
Market Development Specialist (1982 - 1985)
Project Engineer (1979 - 1982) ... promoted from ... **Process Engineer** (1977 - 1979)

OCCIDENTIAL CHEMICAL CORP., Niagara Falls, NY — 1975 - 1977

Research Engineer

PENNSYLVANIA STATE UNIVERSITY, State College, PA — 1988

CLEVELAND STATE UNIVERSITY, Cleveland, OH — 1984

Instructor (Evening Division) - Economics, Engineering Economics

SELECTED ACCOMPLISHMENTS

VICE PRESIDENT, CONSUMER MARKETS - ACN ENERGY

Retained for a turnaround assignment with an independent energy marketing company. Participated on the executive management team and directed a decentralized 3-person market management staff responsible for sales to 85,000 customers. Worked directly with the parent company executives and business unit management to create market-driven strategies for the corporation. Sharpened marketing and sales efforts of an energy marketing company operating in seven states and packaged company for eventual sale to Commerce Energy.

- Primary executive responsible for sales. Directed a team of market managers that was responsible for all aspects of 11 different markets (electric and natural gas) around the country. Provided direction and support to sales channel organization of commissioned representatives. Turned around five-year annual loss to significant gain in 2004. Tightened focus on market decisions.
- Directed regulatory involvement to insure compliance with market rules. Focused on maintaining positive relationships with state utility regulators to avoid penalties.
- Led weekly operations meetings during absence of COO. This involved direction of call center, provisioning, billing, credit & collection, and marketing.
- Worked in a team setting with other executives (VP Finance, VP Supply, COO) to provide consistent, professional focus to workforce experiencing changing environment.
- Directed development of annual business plan and budget with targets resulting in both goal achievements and income improvements.
- During transition period working with merger partner Commerce Energy's executive team to train and advise incoming executives.
- Directed customer service improvements in the customer acquisition process which resulting in replacing outdated paper/fax process with phone order process.
- Organized and directed trade show presence at national sales convention for alliance sales channel to create awareness of new product and market focus.

VICE PRESIDENT, MARKETING - OPTIRON

Retained as part of executive team in venture capital startup company developing new CIS/CRM software for the energy industry. Worked closely with CEO, COO, and Director of Sales to determine business strategy and develop marketing strategy to create market awareness and brand attributes in medium and small energy companies.

- Added in-house marketing communications function and personnel and revamped all marketing materials.
- Added new website functionality and content.
- Implemented first print advertising campaign in industry publications.
- Using industry contacts, positioned Option as expert presenter at several conferences and trade shows.
- Developed business plan to identify sales prospects and created competitive database of CIS/CRM vendors.
- Participated in development of exit strategy plan resulting in the successful sale to large software company.

VICE PRESIDENT, MARKETING & PRODUCT DEVELOPMENT - ERI Services

Assumed responsibility for creating a new corporate marketing vision and strategy to facilitate entry into new deregulated energy markets nationally.

- Recruited and selected an exceptional management team and integrated marketing and sales activities into one functional operating unit.
- Established the product innovation process to identify and create new and profitable market-driven service offerings.
- Directed strategic branding to launch the new corporate identity; managed a $2 million national advertising campaign; and developed over $1 million of new sales/marketing collateral materials.
- Instituted financial controls that reduced costs 60% in the Iowa market rollout while maintaining 80% market share and high customer satisfaction.

VICE PRESIDENT, MARKETING - Citizens Utilities

Directed a decentralized 20-person sales staff and a five person marketing staff. Worked directly with the Board of Directors, Corporate President, and Sector Vice President to create market-driven sales strategies for the corporation. Revamped and redirected sales efforts of a five-state energy utility with 440,000 customers.

- Increased industrial sales revenues by reorganizing unregulated gas marketing effort.
- Revamped merchandising utilizing inbound telemarketing in Louisiana Gas.
- Revised training programs for entire sales force, identifying and correcting missing technical and equipment training, adding a greater competency in the commercial and industrial sectors.
- Developed first business plan in sales and marketing organization with monthly budget monitoring and

targets resulting in both goal achievements and cost improvements.
- ¨ Launched an aggressive direct marketing program that increased sales 500% over previous year.
- ¨ Increased share of gas transportation business in Arizona by 15% in first year of operation through marketing efforts.
- ¨ Created a telephone long distance business in Louisiana that captured a 20% share (2nd to AT & T).

DIRECTOR, RESIDENTIAL & COMMERCIAL MARKETING - Consolidated Natural Gas

Managed a marketing staff of 12 and a "dotted-line" 24-person field sales force. Directed marketing and sales efforts in consumer, business, and manufacturing markets with $154 million revenue.

- ¨ Added $6 million in revenue by developing new products in gas transportation, supply, and agency.
- \- Directed sales activities in residential, commercial, institutional and governmental accounts for both product sales and technology sales.
- ¨ Produced $600,000 annual revenue and doubled competitive project wins by revamping market approaches to residential and commercial new construction.
- ¨ Secured 50% increase in customer decisions over 5 gas companies and 4 electric companies.
- ¨ Experienced in PUC and Legislature lobbying. Increased revenues $2.3 million through regulatory strategy/testifying and received major competitive program approval.

MANAGER, TECHNICAL SALES / MARKET DEVELOPMENT - Consolidated Natural Gas

Directed new market development and competitive market support.

- ¨ Focused on commercial and industrial accounts and increased the depth of relationship beyond the typical utility provider of service to a rich full service information provider and business partner.
- \- Captured $150,000 in new business annually by competitive pricing analysis, sales tool development, and market approach.
- ¨ Developed total advertising and promotional plan launching new market programs.
- ¨ Compiled extensive technical database and developed economic model for project analysis, eliminating a $100,000 operating budget expense.
- ¨ Led statewide coalition with customers and government agencies for fair treatment of new technology.

EDUCATION - PROFESSIONAL

UNIVERSITY OF PITTSBURGH, Pittsburgh, PA 1982
M.B.A. Degree

CARNEGIE - MELLON UNIVERSITY, Pittsburgh, PA 1975
B.S. Degree in Chemical Engineering

Registered Professional Engineer AGA Hall of Fame, 4/1991

JAMES L. CRIST

Lumen Group, Inc.
Suite 101, 4226 Yarmouth Drive ● Allison Park, PA 15101
Phone: 412.487.9708 ●Cell: 412.613.8886 ●E-mail: JLCrist@AOL.com

AMPLIFICATION OF LUMEN GROUP CONSULTING ASSIGNMENTS

A consulting practice specializing in strategic planning, business planning, marketing and venture development in the telecommunications, energy, and services industries.

REGULATORY

Represented the National Energy Marketers Association and their members in Equitable-Dominion Peoples merger case. Developed strategy, presented written and oral testimony and negotiated on behalf of clients. Worked with other interveners and FTC on anti-competitive issues.

UTILITY RATE NEGOTIATION

Represented large client group seeking to obtain rate reduction from electric utility. Prepared strategy, wrote testimony, and exceeded expectations by achieving a 40% reduction in charges, producing a $2 million annual reduction.

STRATEGIC PLANNING FOR ON-SITE POWER GENERATION

Participated in proposal development for a 27-MW power plant on Kauai. Handled critical customer needs assessment in rapid turnaround fashion to meet proposal deadline. Maintained relationships with clients, vendors and proposal partners. Our proposal was selected as the preferred bidder out of five strong competitors.

NEW BUSINESS START-UP / TARIFF NEGOTIATIONS

Participated in the development of a new gas distribution utility in New York. Handled tariff development, pricing structure, transportation contracting, and operations, maintenance, and emergency manual preparation.

SALES STRATEGY/BUSINESS DEVELOPMENT

Developed sales strategy to focus on profitable accounts and markets. Developed sales training and account management plans and provided consulting to energy marketing organizations to improve overall sales.

BUSINESS STRATEGY/BUSINESS DEVELOPMENT

Developed business strategy to verticalize eCommerce/Customer Relationship Management product for the energy/utility industry. Produced sales training for global applications, product promotion presentations, developed alliance relationships with system integrators and software partners, developed business. Client is market leader in North America.

JOINT VENTURE/PRODUCT DEVELOPMENT

Assembled joint ventures resulting in sales to offer new hedge-based weather risk management retail product. Identified venture partners, and developed business arrangements and closed million-dollar deals

ENERGY PROCUREMENT

Served as energy expert on project team that obtained long-term natural gas supply for major government facilities. Prepared project specifications, negotiated with suppliers, prepared RFP, negotiated major reduction in delivery charges. This project resulted in annual cost reduction of $2.5 million.

NEW BUSINESS DEVELOPMENT - TELECOMMUNICATIONS

Analyzed use of electric utility assets for possible telecommunications business venture. Wrote the business plan that identifies regulatory and non-regulatory issues, marketing plans, financial analysis, and organizational requirements. Launched the new non-regulated business unit in 1996.

JOINT VENTURE DEVELOPMENT - TELECOMMUNICATIONS

Conducted analysis of potential joint venture partners for new unregulated telecommunications venture, bypassing the Bell operating company. Held screening discussions with potential partners and selected lead candidate for venture. Developed working agreement with partners along with business case to launch venture.

JOINT VENTURE DEVELOPMENT - TELECOMMUNICATIONS & ENERGY

Developed strategic plan for joint venture involving gas, electric, and telecommunications partners. Screened potential business partners and held discussions with lead candidates. Assembled justification for top management approval.

PRODUCT DEVELOPMENT - UNREGULATED ENERGY SERVICES

Developed energy products for start-up subsidiary of major energy utility. Identified potential products and selected most likely candidates for further development. Developed market plans and sales plans for products.

MARKET PLAN - DIRECT MARKETING

Developed the market plan for large, global direct marketing agency to enter the energy industry. Identified strategies, strengths, weaknesses, and target prospects. Initiated sales effort and developed new business.

CORPORATE IMAGE DEVELOPMENT

Developed complete business unit identity for a new operations and services company. Produced capabilities brochure for use with prospects.

MARKET RESEARCH

Conducted market research to identify new customer/new business opportunities for major energy utility. Comprehensive project with two additional similar projects were completed. Entailed determination of goals, development of research methodology, script preparation, vendor selection, data analysis, and development of action plan.

MARKET DEVELOPMENT

Organized intervener group in Illinois consisting of retail marketers and intervened in three rate proceedings (Nicor Gas base case, WPS-Peoples merger case, Peoples Gas base case) and secured significant improvements in rules and procedures enabling marketers to increase their business and profitability. Developed strategy and presented written and oral testimony.

EXHIBIT JC-2

PARTIAL LIST OF REGULATORY EXPERIENCE OF JAMES L. CRIST

1. Philadelphia Gas Works, Base Rate Case, Docket R-2023-3037933, Representing Grays Ferry Cogeneration Partnership
2. Columbia Gas of Kentucky, Tariff Filing of Columbia Gas of Kentucky to Extend Its Small Volume Gas Transportation Service, Case No. 2021-00386, Representing Interstate Gas Supply, Inc, Constellation New Energy Gas Division, LLC, Xoom Energy Kentucky, LLC
3. Chattanooga Gas Company, Petition for Approval of Tariff Amendments, Docket No. 22-00004, Representing Chattanooga Regional Manufacturers Association
4. Chattanooga Gas Company, Petition for Approval of its 2021 Annual Rate Review Filing, Docket No. 22-0032, Representing Chattanooga Regional Manufacturers Association
5. Duke Energy Ohio, Application for Tariff Approval, Case No. 20-0054-GA-ATA, Representing Retail Energy Supply Association
6. Black Hills Wyoming Gas, Application for Authority to Revise Certain Tariff Provisions, Docket 30026-GA-21, Representing Wyoming Community Gas
7. West Penn Power Company, Default Service Program, Docket P-2021-3030021, Representing the Pennsylvania State University
8. Columbia of PA General Base Rate Increase, Docket R-2021-3025775, Representing the Pennsylvania State University
9. Columbia of PA General Base Rate Increase, Docket R-2020-3018835, Representing the Pennsylvania State University
10. Dominion Energy Ohio Motion, Case No. 18-1419-GA-EXM, Representing Retail Energy Supply Association
11. Aqua America/Peoples Natural Gas Merger, Docket R-2018-3006061, Representing Natural Gas Supplier Parties and Retail Energy Supply Association
12. Peoples Natural Gas General Base Rate Increase, Docket R-2018-3006818, Representing Peoples Industrial Intervenors
13. Duquesne Light Company General Base Rate Increase, Docket R-2018-3000124, Representing the Duquesne Industrial Intervenors
14. Columbia of PA General Base Rate Increase, Docket R-2018-2647577, Representing the Pennsylvania State University
15. West Penn Power Company, Default Service Program, Docket R-2017-2637866, Representing the Pennsylvania State University
16. Vectren Energy Delivery Ohio, Alternative Rate Plan, Case No. 18-0049-GA-ALT, Representing Retail Energy Supply Association
17. Columbia of PA Gas Cost Increase, Docket R-2017-2591326, Representing the Pennsylvania State University
18. West Penn Power Company, General Base Rate Increase, Docket R-2016-2537359, Representing the Pennsylvania State University
19. Columbia of PA General Base Rate Increase, Docket R-2016-2529660, Representing the Pennsylvania State University
20. UGI Utilities General Base Rate Increase, Docket R-2015-2518438, Representing Dominion Retail, Inc., Shipley, Choice, LLC, Interstate Gas Supply, Inc., Amerigreen Energy, and Rhoads Energy
21. Columbia of PA General Base Rate Increase, Docket R-2015-2468056, Representing the Pennsylvania State University
22. West Penn Power Company, General Base Rate Increase, Docket R-2014-2428742, Representing the Pennsylvania State University
23. Herman Oil & Gas Company, General Base Rate Increase, R-2014-2414379, Representing Herman Oil & Gas Company
24. Columbia of PA General Base Rate Increase, Docket R-2014-2406274, Representing the Pennsylvania State University
25. Ameren Gas- General Base Rate Increase, Docket No. 13-0192, Representing Dominion Retail and Interstate Gas Supply of Illinois
26. Columbia of PA General Base Rate Increase, Docket R-2012-2321748, Representing the Pennsylvania State University, Dominion Retail, Interstate Gas Supply, and Shipley Energy
27. Columbia of PA Petition for Approval of a Distribution System Improvement Charge Docket R-2012-2338282, Representing the Pennsylvania State University
28. PUC PA Generic Investigation Regarding Gas-On-Gas Competition, Docket No. P-2011-2277868, Representing the Pennsylvania State University
29. Ameren Gas- General Base Rate Increase, Docket 11-0282 (Cons.), Representing Dominion Retail and Interstate Gas Supply of Illinois
30. Water and Power Authority (USVI)- Electric Base Rate Case, Docket 575, June 2009, Representing Frenchman's Reef Marriott
31. Water and Power Authority (USVI)- Water Base Rate Case, Docket 576, June 2009, Representing Frenchman's Reef Marriott

32. Public Service of New Mexico 2010 Base Rate Case, Informal rate design workshops pursuant to the stipulation in NMPRC Case No. 08-00273-UT, Representing City of Albuquerque
33. Public Service of New Mexico, Electric base case at Case No. 08-00273-UT, Representing City of Albuquerque
34. Public Service of New Mexico 2009 Renewable Energy Procurement Plan for 2010, Case No. 09-00260-UT, Representing City of Albuquerque and Santa Fe County
35. Public Service of New Mexico, Gas sale case at Case No. 08-00078-UT, Representing City of Albuquerque
36. UGI Utilities, Central Penn Gas, Penn Natural Gas, Gas Cost Increase, Docket No. R-2011-2238953, Representing Shipley Energy, Rhodes Energy, and CenterPoint Energy
37. UGI Utilities- Gas Division, Gas Cost Increase, Docket No. R-2010-2172933, Representing Shipley Energy
38. Columbia of PA General Base Rate Increase, Docket R-2010-2215623, Representing the Pennsylvania State University, Dominion Retail, Interstate Gas Supply, and Shipley Energy
39. Columbia of PA General Base Rate Increase, Docket R-2009-2149262, Representing the Pennsylvania State University, Dominion Retail, Interstate Gas Supply, and Shipley Energy
40. Columbia of PA General Base Rate Increase, Docket R-2008-2011621, Representing Hess Energy, Dominion Retail, Interstate Gas Supply, and Shipley Energy
41. Columbia of PA Gas Cost Increase, Docket R-2008-2028039, Representing Dominion Retail, Interstate Gas Supply, and Shipley Energy
42. PPL Electric Utilities Voluntary Purchase of Accounts Receivables Program and Merchant Function Charge, Docket No. P-2009-2129502
43. Nicor Gas Company, Provision of facilities and services and the transfer of assets between Nicor Gas Company and Nicor Inc., Docket No. 09-0301, Representing Dominion Retail
44. North Shore Gas and Peoples Gas Light and Coke Company, General Base Rate Increase, Dockets 09-0166 and 09-0167, Representing Dominion Retail, Interstate Gas Supply and Nicor Advanced Energy
45. Nicor Gas Company, Base Rate Increase, Docket No. 08-0363, Representing Interstate Gas Supply and Dominion Retail
46. North Shore Gas and Peoples Gas Light and Coke Company, General Base Rate Increase, Dockets 07-0241 and 07-0242, Representing Dominion Retail, Interstate Gas Supply and U.S. Energy Savings
47. WPS Resources, Peoples Energy, Peoples Gas Light and Coke Company, North Shore Gas Company, Application pursuant to Section 7-204 of the Public Utilities Act for authority to engage in a Reorganization, Docket 06-0540, Representing Dominion Retail, Interstate Gas Supply, US Energy Savings, MxEnergy, and Direct Energy Services.
48. Allegheny Energy, Approval of Retail Electric Default Service Program and Competitive Procurement Plan, Docket No. P-2008-2021608, Representing the Pennsylvania State University
49. Allegheny Energy, Generation Rate Cap, Docket No. P-2007-2001828, Representing the Pennsylvania State University
50. Equitable Gas Company, Rate Increase, Docket R-2008-2029325, Representing Independent Oil & Gas Association and Hess Corp.
51. Equitable Gas Company and Peoples Gas, Merger Case, Docket A-122250F5000, Representing National Energy Marketers, Hess Corporation, and Constellation New Energy.

EXHIBIT JC-3

Question 14

Request:

Regarding the language of the regulation, "An EDC and 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." Produce a table portraying calculated GSR-1, GSR-2 monthly average rates for the historic period 6/2021-6/2024 and forecast rates for the period 7/2024 through 5/2029. Explain basis of forecast pricing.

Response:

Please see Attachment PENN-III-14 for historic period rates.

The forecasted rate for GSR-1 customers for the quarter-beginning September 1, 2024 is $0.11064/kWh. The forecast is based on projected costs with a true-up of experienced cost and revenue, as outlined in UGI Electric Tariff No. 6, pages 39 - 40. Forecasts are not available for other future periods.

UGI Electric does not forecast rates for GSR-2.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Electric Division
Historic Monthly Default Service Rates ($/kWh)
June 2021 - June 2024

	GSR-1	GSR-2*
Jun-21	0.06331	0.04613
Jul-21	0.06331	0.03987
Aug-21	0.06331	0.07744
Sep-21	0.06218	0.07496
Oct-21	0.06218	0.07041
Nov-21	0.06218	0.08575
Dec-21	0.09005	0.07920
Jan-22	0.09005	0.06662
Feb-22	0.09005	0.07336
Mar-22	0.08853	0.07028
Apr-22	0.08853	0.07566
May-22	0.08853	0.08799
Jun-22	0.12902	0.10316
Jul-22	0.12902	0.10330
Aug-22	0.12902	0.10995
Sep-22	0.12902	0.13449
Oct-22	0.12902	0.09455
Nov-22	0.12902	0.08026
Dec-22	0.12902	0.08012
Jan-23	0.12902	0.14616
Feb-23	0.12902	0.05827
Mar-23	0.12539	0.05352
Apr-23	0.12539	0.05126
May-23	0.12539	0.05956
Jun-23	0.11083	0.04790
Jul-23	0.11083	0.04701
Aug-23	0.11083	0.05266
Sep-23	0.12128	0.04456
Oct-23	0.12128	0.04736
Nov-23	0.12128	0.05570
Dec-23	0.10260	0.05883
Jan-24	0.10260	0.05148
Feb-24	0.10260	0.05869
Mar-24	0.09978	0.04364
Apr-24	0.09978	0.04523
May-24	0.09978	0.05167
Jun-24	0.10525	0.05438

*GSR-2 Rates were calculated by taking billed revenue divided by billed sales.

EXHIBIT JC-4

Question 2

Request:

In UGI's petition at pages 20-21, UGI claims that GSR-2 net metering customers will be paid the "price to compare applicable to GSR-2 customers." Explain in detail how the PTC will be calculated. Will this PTC be published on the UGI's website? Is it expected to be materially different from GSR-1 PTC?

Response:

Please see Attachment PENN-I-2 for an example PTC-2 calculation detail. The provided calculation shows two hours: one where a customer is net consuming and one where the customer is net generating. This example is for illustrative purposes and assumes an LMP value of $40/MWh. PJM charges that are allocated based on PLC values are assumed at zero, using the assumption that a larger customer generator will be net generated during the hourly periods which establish PLC values. PJM charges that are allocated based on NSPL values were calculated using the average per kW charges from the May 2024 billing month, with the assumption that a larger customer generator will have a net consumption for 50% of the hourly periods which establish NSPL values. A per kWh rate for PJM charges that are allocated based on kWh was calculated by dividing costs by sales for the May 2024 billing month. Finally, a per kWh rate for administrative & general (A&G) charges was calculated in the same manner.

As PTC-2 will be an hourly rate applicable to each specific GSR-2 customer, publishing a specified rate is not possible. UGI Electric does plan to include the following language on its website: "The Price to Compare for GSR-2 (PTC-2) shall include the GSR-2 rate and the State Tax Surcharge in Rider A."

Depending on the point(s) in time when compared, UGI Electric does anticipate that the GSR-2 PTC-2 will differ from GSR-1 PTC-1, either higher or lower.

Prepared by or under the supervision of: James M. Rouland

UGI UTILITIES, INC. – ELECTRIC DIVISION
GSR-2 CUSTOMER PRICE TO COMPARE EXAMPLE CALCULATION

Line #	Line Item Description	Example of Hour Net Consumption (kWh)	Example of Hour Net Generation (kWh)
1	kWh (metered value)	100	(1,000)
2	Applicable hourly EHV Loss percentage (from PJM)	0.6%	0.6%
3	Total loss percentage with inclusion of 6.5% UGI system loss (L2+6.5%)	7.1%	7.1%
4	Loss gross up factor (1-L3)	92.9%	92.9%
5	Grossed up kWh for losses (L1/L4)	108	(1,076)
6	Applicable hourly deration factor (from PJM)	3.9%	3.9%
7	Deration factor (1-L6)	96.1%	96.1%
8	kWh (with deration) (L5*L7)	103	(1,034)
9	LMP ($/MWh)	$ 40.0000	$ 40.0000
10	LMP ($/kWh) (L9/1000)	$ 0.0400	$ 0.0400
11	Total LMP charges (L8*L11)	$ 4.1378	$ (41.3778)
12	PJM allocated charges - PLC based ($/kW) /A	$ -	$ -
13	PJM allocated charges - NSPL based ($/kW) /B	$ 0.6375	$ 0.6375
14	PJM allocated charges/(credits) - kWh based ($/kWh)	$ (0.0076)	$ (0.0076)
15	Total PJM allocated charges/(credits) - kWh based (L8*L14)	$ (0.7862)	$ 7.8618
16	DSP A&G allocated costs - kWh based ($/kWh)	$ 0.0070	$ 0.0070
17	Total DSP A&G allocated costs - kWh based (L8*L16)	$ 0.7241	$ (7.2411)
18	Net Metering Purchase Reconciliation /C (charge/(credit)*L8)	$ -	n/a
19	Total GSR-2 (L11+L12+L13+L15+L17+L18) excluding GRT	$ 4.7132	$ (40.1197)
20	Total GSR-2 charges including GRT (L19/(1-5.9%))	$ 5.0087	$ (42.6351)
21	STAS (currently 0%)	0.00%	0.00%
22	Total PTC-2 (L20*(1+L21))	$ 5.0087	$ (42.6351)
23	Unit PTC-2 (per kWh) (L22/L8)	$ 0.0484	$ 0.0412

/A - Assumes PLC value of zero (net generation during all PLC hours)
/B - Assumes NSPL value of 50kW (net consumption on 50% of NSPL hours)
/C - Assumes no current reconciliation charges/(credits)

EXHIBIT JC-5

UGI Utilities, Inc. - Electric Division
Docket No. P-2024-3049343
UGI Electric Default Service Plan
Responses to Penn Renewables Set II (1-10)
Delivered on July 11, 2024

Question 1

Request:

Assuming that net metered Customer Generators produce excess electric energy, does this excess generation physically and/or financially flow into the distribution facilities of the Company or into the PJM transmission system? How will UGI denote such flows in its scheduling/balancing?

a. If into the distribution system, when and where is it consumed?

b. If into the transmission system, when and where is it consumed?

c. If not, where does the excess energy flow, and when and where is it consumed

Response:

Currently all net metering customers are interconnected to the UGI Electric distribution system. As such, excess generation from these net metering facilities physically flows into the distribution system. Excess generation is recorded by the customer's meter. At a local level, if export of energy from net metering facilities exceeds the total load of the substation, the export flows to the transmission system.

There are two important processes that occur simultaneously but separately – those of the physics of the electric grid and those of market settlement and financial accounting. UGI Electric is proposing to implement the 100 kW supply peak load impact demarcation to better align with market settlement and financial accounting. As related to the physics of electricity in how energy flows and is consumed, no physics or physical changes are being proposed in DSP V. As explained in PENN-I-3, UGI Electric schedules and settles the UGI zone for GSR-2 customers in aggregate, not on a per-customer basis. As such, net metering customer data – consumption and export – is aggregated with other GSR-2 customer data when scheduled through PJM. Excess generation by net metering customers first reduces the amount of energy UGI Electric must procure through the PJM spot market for GSR-2. If excess generation then exceeds consumption in any hour, that excess generation is sold to the PJM spot market.

Prepared by or under the supervision of: James M. Rouland

EXHIBIT JC-6

Question 8

Request:

Please add columns on Attachment Penn I-2

a. to include an example for a comparable non-generating GSR-2 customer of similar 1,000 kW load;

b. that demonstrates the PTC if the customer generator, assuming all other factors remain the same, is producing at 100 kw in a given hour; and

c. that demonstrates the PTC if the customer generator is producing at 200 kw in a given hour.

Response:

Please see Attachment PENN-III-8.

Prepared by or under the supervision of: James M. Rouland

UGI UTILITIES, INC. – ELECTRIC DIVISION
GSR-2 CUSTOMER PRICE TO COMPARE EXAMPLE CALCULATION

Line #	Line Item Description for GSR-2 Customer	Example of Hour Net Consumption (kWh)	Example of Hour Net Generation (kWh) /D	Example of Hour Consumption (kWh) Non-Customer Generator	Example of Hour Net Generation (kWh) /D	Example of Hour Net Generation (kWh) /D
1	kWh (metered value)	100	(1,000)	1,000	(100)	(200)
2	Applicable hourly EHV Loss percentage (from PJM)	0.6%	0.6%	0.6%	0.6%	0.6%
3	Total loss percentage with inclusion of 6.5% UGI system loss (L2+6.5%)	7.1%	7.1%	7.1%	7.1%	7.1%
4	Loss gross up factor (1-L3)	92.9%	92.9%	92.9%	92.9%	92.9%
5	Grossed up kWh for losses (L1/L4)	108	(1,076)	1,076	(108)	(215)
6	Applicable hourly deration factor (from PJM)	3.9%	3.9%	3.9%	3.9%	3.9%
7	Deration factor (1-L6)	96.1%	96.1%	96.1%	96.1%	96.1%
8	kWh (with deration) (L5*L7)	103	(1,034)	1,034	(103)	(207)
9	LMP ($/MWh)	$ 40.0000	$ 40.0000	$ 40.0000	$ 40.0000	$ 40.0000
10	LMP ($/kWh) (L9/1000)	$ 0.0400	$ 0.0400	$ 0.0400	$ 0.0400	$ 0.0400
11	Total LMP charges (L8*L11)	$ 4.1378	$ (41.3778)	$ 41.3778	$ (4.1378)	$ (8.2756)
12	PJM allocated charges - PLC based ($/kW) /A	$ -	$ -	$ 0.2597	$ -	$ -
13	PJM allocated charges - NSPL based ($/kW) /B	$ 0.6375	$ 0.6375	$ 1.2750	$ 0.6375	$ 0.6375
14	PJM allocated charges/(credits) - kWh based ($/kWh)	$ (0.0076)	$ (0.0076)	$ (0.0076)	$ (0.0076)	$ (0.0076)
15	Total PJM allocated charges/(credits) - kWh based (L8*L14)	$ (0.7862)	$ 7.8618	$ (7.8618)	$ 0.7862	$ 1.5724
16	DSP A&G allocated costs - kWh based ($/kWh)	$ 0.0070	$ 0.0070	$ 0.0070	$ 0.0070	$ 0.0070
17	Total DSP A&G allocated costs - kWh based (L8*L16)	$ 0.7241	$ (7.2411)	$ 7.2411	$ (0.7241)	$ (1.4482)
18	Net Metering Purchase Reconciliation /C (charge/(credit)*L8) ($/kWh)	$ -	n/a	$ -	n/a	n/a
19	Total GSR-2 (L11+L12+L13+L15+L17+L18) excluding GRT	$ 4.7132	$ (40.1197)	$ 42.2919	$ (3.4382)	$ (7.5139)
20	Total GSR-2 charges including GRT (L19/(1-5.9%))	$ 5.0087	$ (42.6351)	$ 44.9435	$ (3.6538)	$ (7.9850)
21	STAS (currently 0%)	0.00%	0.00%	0.00%	0.00%	0.00%
22	Total PTC-2 (L20*(1+L21))	$ 5.0087	$ (42.6351)	$ 44.9435	$ (3.6538)	$ (7.9850)
23	Unit PTC-2 (per kWh) (L22/L8)	$ 0.0484	$ 0.0412	$ 0.0434	$ 0.0353	$ 0.0386

/A - Assumes PLC value of zero (net generation during all PLC hours) for customers with usage of 100 kWh, (1,000) kWh, (100) kWh & (200) kWh and a PLC of 100 kW for customer with usage of 1,000 kWh.
/B - Assumes NSPL value of 50kW (net consumption on 50% of NSPL hours) for all scenarios except for customer with usage of 1,000 kWh which utilizes an NSPL value of 100kW (indicative of 100kW load during all NSPL hours).
/C - Assumes no current reconciliation charges/(credits)
/D - Values shown in Line 1 for generating customers are representative of net production over an hourly period

EXHIBIT JC-7

Question 1

Request:

Provide a definition of “supply peak load impact” as used by UGI in the Petition and testimony.
a. Does the definition of "supply peak load impact differ from “peak load”, and if so, explain the difference.
b. Confirm that there is no definition of “peak load” in UGI’s tariff, if you cannot confirm, provide the definition as it appears in UGI’s tariff.
c. Provide UGI’s operating definition of “peak load”

Response:

As defined on page 39 of the proforma tariff supplement, supply peak load impact will be determined on 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 supply peak load impact used to assign customers to the applicable GSR rate shall be the Customer’s highest supply peak load impact (kW) in the most recent 12-month period ending September 30. For new customers without a 12-month history, supply peak load impact shall be based on the Company’s estimate using factors such as, but not limited to, similarly equipped buildings, 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.

a. “Peak load” constitutes the Customer’s peak ability to draw power from the UGI distribution system whereas “supply peak load impact” considers the total peak impact which must be considered by the Company related to default service obligations, inclusive of the Customer’s ability to generate power and feed such power back into the UGI distribution system.

b. As related to the Company’s current default service criteria, the “Customer’s highest billing demand in the twelve-month period ending September 30, 2020, shall be the annual peak load determinant for purposes of applying the GSR.” (see UGI Electric tariff, Second Revised Page No. 39).

c. Please see the response to (b), above.

Prepared by or under the supervision of: James M. Rouland

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029	:	Docket No. P-2024-3049343 C-2024-3049618

SURREBUTTAL TESTIMONY OF JAMES L. CRIST, P.E.
ON BEHALF OF
PENN RENEWABLES, LLC

Penn Renewables Statement No. 1-SR
September 25, 2024

Q. PLEASE STATE YOUR NAME, AND ON WHOSE BEHALF, YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc. and am presenting surrebuttal testimony on behalf of Penn Renewables ("Penn"). Previously, I presented direct testimony in this proceeding.

Q. WHAT ARE THE ISSUES YOU WILL ADDRESS IN THIS SURREBUTTAL TESTIMONY?

A. I will respond to the several comments made by Company witnesses Mr. Rouland, now Mr. Faryniarz, and Ms. Hazenstab, and by the Office of Consumer Advocate ("OCA") witness Mr. Ogur. Their recommendations are contrary to the AEPS statue and will result in higher costs for customers, which is unacceptable.

UGI's DSP V plan, with regard to GSR-2, is intended to create intolerable risk for customer-generators, in flagrant violation of the AEPS Act and Commission Regulations. Regardless of what Mr. Faryniarz and Ms. Hazenstab contend; this approach does not comport with the statutory or regulatory requirements that apply to net metered projects and is intended to expose customer-generators to a high level of risk that their projects will not be built.

In response to their recommendations, I will also provide additional evidence demonstrating that their recommendations, which are contrary to the AEPSA, harm customer generators, small business customers, and residential customers. If UGI's plan

is approved the likely outcome is that fewer alternative energy projects will be built, and customers will pay higher prices for electricity.

As a recap, UGI has proposed to continue to group all of its customers into two procurement groups, but rather than base the grouping on peak demand as it did in previous DSPs, it now proposes to base the classification upon a novel concept which it calls System Peak Load Impact ("SPLI"), a concept that is not defined or discussed in the statutes or regulations, nor by any other utility in the Commonwealth. The regulations continue to mandate non-discriminatory treatment of customers based on registered peak demand or load. Peak load and UGI's concocted term SPLI are not the same.

UGI's plan is to pay a price to suppliers for excess generation, not at a retail price, but at a wholesale price determined by a pricing formula that can produce two wildly different rates that are not related to the rate UGI is charging similarly sized customers. One rate is determined to compensate a customer generator for excess generation and a different rate is determined to charge a customer, even if the customer has the same consumption as a customer generator is producing. There is no rationale to such discriminatory pricing, and it harms customer-generators.

UGI contends that it is justified in doing so because suppliers will enter and exit the market to extract the most money they can and therefore can avoid generating during periods that position them at a price disadvantage. That is not the intention of customer-generators. Customer-generators operate to produce as much energy as they can. Solar projects specifically produce power during the daytime when the sun is shining and produce no power at nighttime. They are likely not equipped with the physical ability to rapidly turn

their small systems on and off, nor is the pricing of the proposed tariff transparent and posted to give customer-generators the knowledge of when to enter and exit the market.

Q. WHAT ARE THE DEFAULT SERVICE RATES IN THE UGI TARIFF?

A. UGI has two rates available for customers that choose to receive electric supply from UGI under Rider B, the Generation Supply Service Surcharge. GSR-1 is the rate providing stability with adjustments quarterly, that applies for residential, small business, and commercial customers with peak loads less than 100 kW. This rate is applied to over 99% of UGI's customers and is the appropriate rate for excess power produced by small net generation metered projects. GSR-2 is an unpredictable hourly rate that applies to customers with peak load greater than or equal to 100 kW. UGI desires to apply this rate too small net metered projects, and such an application will have a chilling effect on project development.

Q. WHAT IS THE WHOLESALE POWER MARKET?

A. The wholesale power market is supplied by large, utility-scale generators, whose power is contractually sold to utilities that supply their retail customers, or marketers that supply customers participating in programs that allow them to receive non-utility supply.

Q. WHAT IS THE RETAIL POWER MARKET?

A. In the retail power market, suppliers provide electric supply to end-user customers. When viewed with the wholesale market, the combination is similar to other commodity supply

arrangements that have large producers selling at wholesale to middlemen, that in turn, mark up the price, and sell at retail to end user customers.

Q. IS UGI'S SCHEME PERMITTED BY THE AEPS?

A. No. UGI presents no evidence regarding the supposed ease of moving between the wholesale market, which is the market that UGI intends for non-residential customer generators on its system, and the retail market, which is what the AEPS Act intends for customer-generators. Not surprisingly, there is no evidence that customer-generators actually can or do move between these two markets.

Q. WHAT IS "FULL RETAIL VALUE" IN UGI'S SYSTEM?

A. The vast majority of UGI's customers pay for power at a quarterly fixed price under the Full Retail Value GSR-1 rate. This is the best definition of Full Retail Value that can be applied to the UGI system. UGI stated in its DSP III in 2016, GSR-2 is an hourly price service, and that GSR-2 customers look to the retail market to provide necessary service offerings. Over the last 4 years, UGI has had an average of 117 customers on GSR-2 pricing. During the last four quarters, fully 56 of its 175 total GSR-2 customers (32%) left that rate and 26 of those customers were on GSR-2 pricing for one quarter only. Per UGI's petition, it has 69,000 customers. Only 0.17% of its customers, who comprise an average of 1.03% of load are at GSR-2 pricing. GSR-2 pricing applies to a very small portion of UGI's customer load whereas GSR-1 pricing applies to 99% of its customers, indicating that for the Penn Renewables solar project, which are 10 kW, GSR-1 pricing is the appropriate rate. This data is presented in the response to Penn Renewables Set III-14

and included as **Exhibit JC-8**. The GSR-2 price is clearly not Full Retail Value of the usual and customary rate for a residential and small commercial customer.

Q. DOES THE AEPS REQUIRE PAYING CUSTOMER-GENERATORS THE RETAIL VALUE FOR POWER?

A. Contrary to Mr. Faryniarz's speculation, paying customer-generators the actual "Full Retail Value" is what the law requires and is not subsidization. While the vast majority of UGI customers will pay a "Full Retail Value" at the GSR-1 rate, UGI's plan proposes to pay customer-generators at a low wholesale rate for generation they convey to the distribution system, on the very same wires upon which the Full Retail Value GSR-1 customers are served. The fact that the GSR-2 default service rate under UGI's proposal is likely to be negative under commonly occurring circumstances does not seem to concern Mr. Faryniarz. Rather, Mr. Faryniarz claims that a negative default service rate (i.e., the customer-generator actually being charged for energy that it is producing and that is being consumed by its neighbors at the Full Retail Value GSR-1 rate) is a price signal to the customer-generator to stop generating electricity. This is contrary to the APES that places no limitation on the ability of customer-generators to operate based on a wholesale price signal, yet UGI's GSR-2 PTC is such a price signal and UGI admits that the GSR-2 PTC is settled in the wholesale market.

Q. DOES UGI TREAT LINE LOSSES IN ACCORDANCE WITH THE AEPS?

A. No. Line losses are another of those seemly innocuous items that demonstrate UGI's flagrant disregard for the law. The AEPS Act requires that customer-generators be

compensated for the electric energy they produce, "at the delivery point" i.e., the meter, yet UGI insists on including line losses in the calculation of the compensation for excess energy because that is how wholesale transactions are constructed. This insistence reflects UGI's determination to employ its methodology regardless of what the law says.

Q. WHAT COMMENTS DID MR. FARYNIARZ MAKE THAT YOU OBJECT TO?

A. Right of the bat, Mr. Faryniarz mischaracterizes the projects of Penn Renewable as "large projects" that will have a negative effect on the power supply market.[1] The truth is actually the polar opposite of Mr. Faryniarz's statement. The 12 projects of Penn Renewable planned in the UGI territory are small, under 2,000 kW each, and are typical of all of the Penn Renewable projects under consideration in the Commonwealth. They are exactly the type of project that the legislation encourages, that is, a multitude of small projects (most under 2,000 kW) that would develop around the Commonwealth to address climate change, provide alternative generation supply choices, and reduce the burden on distribution and transmission systems by their non-concentrated locations. Mr. Faryniarz's prediction of the projects' effect on prices and competition in the power supply market is contrary to the fundamental laws of economics we know to be true. When additional suppliers enter a market, there is increasing competition, and prices trend lower to become more competitive. This is the benefit that will be realized by encouraging the development of small solar projects. Mr. Faryniarz and UGI wish to stifle this development.

Currently there are no solar projects listed on the PJM website as operating in the wholesale market under 3,000 kW and only two under 10,000 kW. The average size is 20,000 kW,

[1] "This estimated supply amount is substantive and is likely to result in higher bid prices and/or lower supplier participation" Statement 2-R,18:2-3.

and the largest is 150,000 kW. Small generators like those proposed by Penn Renewables typically do not operate in the wholesale market. Thus, it is reasonable to expect that small customer-generators will choose not to enter the UGI market if this wholesale pricing regime is forced upon them. Mr. Faryniarz has wrongly contended that customer-generators can choose to enter or exit a market at will, and UGI's proposal would ensure customer-generators do not have a reasonable or profitable way of entering the UGI market so will choose not to.

Q. HOW DO PROJECTS SIZED FROM 1,000 TO 2,000 kW BENEFIT GSR-1 CUSTOMERS?

A. There are economies of scale in solar projects that project positive economic benefits and lower costs of power generated. Flowing such power into the supply portfolio of GSR-1 customers provides additional competitive supply, reduced transmission flows/costs, and increases reliability for that customer group. Pricing the power generated from such projects at the value of supply pricing for Full Retail Value GSR-1 customers is entirely appropriate.

Q. WHY IS IT UNREASONABLE TO CLASSIFY PROJECTS BASED ON THEIR PEAK SUPPLY?

A. Classifying customers as GSR-1 or GSR-2 based upon peak load impact, which can be based either on a customer's consumption – i.e., load – or production – i.e., generation supply -- is premised on the fallacy that distribution system costs increase with usage. UGI has submitted no evidence that O&M costs vary significantly with the amount of energy

flowing through the system. Moreover, the capital expenses needed to ensure that the distribution system is able to receive and distribute the energy generated by a customer-generator are paid-for by the customer-generator as part of the interconnection study and deposit process. The primary impacts of customer-generators are to reduce the amount of energy that must be purchased to serve load on the system, and these reductions, while "variable", occur on a regular schedule correlated with the sun. Vilifying and punishing customer-generators in the form of the lower rates that UGI proposes to pay customer-generators for producing energy is contrary to both the AEPS Act's intention and its specific requirements; to encourage alternative energy production.

Q. WHY IS DEBITING CUSTOMER-GENERATORS NOT APPROPRIATE?

A. The law is specific that "excess generation from net metered customer-generators shall receive Full Retail Value for all energy produced on an annual basis."[2] The Commission's regulations explain that customer-generators are to be credited for each kWh produced in excess of consumption. UGI's debiting scheme does not do that. Rather, UGI proposes to create a customer-generator specific default service rate that varies on the basis of multiple components and which can go negative, which means a customer-generator is not being credited any value for the power it produces, but actually charged for doing so. The so-called GSR-2 rate does not reflect anything close to "Full Retail Value." Under a GSR-2 scenario, UGI's proposed hourly price will not be the same for any two customers. This proposed tariff setup is overly complex and opaque. It is at best, a "square peg in a round hole" and at worst, created to disincentivize a group of unwanted small customer-

[2] 73 P.S. §1648.5.

generators. UGI's claim that the "calculation is the same for all customers" is simply untrue. When combined and graphed operationally, the result is clearly not the same as the retail value of power. It is abundantly clear that the rate is designed to not provide Full Retail Value during periods of solar production.

Q. WHAT PARAMETERS IMPACT UGI'S PROPOSED RATE?

A. Referring to UGI's proposed formula, supplied by Mr. Faryniarz as the response to PENN III-8 and included as **Exhibit JC-9,** there are three parameters, and they differ depending on whether a customer is consuming power or producing power.

First, some elements of the bill, such as kWh's (line 1), the tariff allows both positive and negative numbers, positive for load (consumption) and negative for supply. Other line items are positive for load only and are recorded as zero for demand (line 12 and 13). This demonstrates that UGI is "cherry picking" -- for some elements it is focused on "load" centric pricing, and not supply based. This demonstrates they do not believe their own arguments regarding supply impact.

Second, since some of the tariff has demand-related values, there will likely be a "demand" portion to the price which remains as a fixed dollar amount in each hour. Thus, as demand or supply approaches less than 5 kWh per hour, the per kWh rate starts to act asymptotically, reaching 100's of cents per kWh for energy. The level of demand Penn Renewables projects are expected to operate in during non-operating times is 2-5 kWh per hour. Note that Full Retail Value GSR-1 is usually around 10 cents per kWh, for every kWh. This "fixed" portion results in declining Unit PTC-2 as consumption increases, as shown in **Exhibit JC-11**.

Thus, if two identical customers were supplying different levels of energy, they would be receiving Unit PTC-2 prices (in $/kWh) that were not identical.

Third is the state of customer during the five PLC and NSPL hours each year. In **Exhibit JC-11**, it can be seen how different the prices will apply for a selection of potential output or load states of a customer, even though the LMP price is the same. For many of these potential states, the assumption is that the PLC is zero. Penn Renewables also believes that a PLC of zero is not an incorrect assumption as it is likely the customer will be supplying energy to the system (that is, will have no load). This means there will be no charge or credit for capacity. However, hypothetically, allowing these demand values to also move negative for supply would result in massive amounts of negative pricing when customers are supplying power to the system. Since these values are then refunded, operationally, this would result in a "charge" for the production of energy rather than a refund. This clearly is not what the AESP intended as "Full Retail Value."

In the end, this creates a pricing paradigm where prices are 1.5x the GSR-1 rate when a customer-generator is a "load" (i.e. net users of energy), but only 20-30% of the Full Retail Value GSR-1 price on average when a customer-generator is supplying power. Worse, there are times where UGI's proposed formula would actually charge the customer-generator for supplying power. Obviously, charging a small solar power producer for providing power makes no sense, yet this is what UGI's proposed pricing formula would do. The proposed payment scheme would be further complicated if the customer-generator were employing virtual net metering and there were multiple meters supplied from a single customer-generator. In such case there would be different rates and the same customer

generator would realize different prices, completely interrupting the intent of the Virtual Net Metered payment structure.

Q. DOES UGI'S PROPOSED PLAN PROVIDE PRICE STABILITY?

A. No. It provides the opposite of price stability; it will lead to constantly changing prices that will depend not only on wholesale prices, but also on the state of a customer-generator (load or supply), as well as the amount of energy being consumed or supplied. The hourly pricing will be opaque until the monthly bill is sent weeks later. Such a pricing scheme places the customer-generator at risk. The Legislature passed the AEPS Act to incentivize production of clean and renewable energy by establishing a published, infrequently changing payment at full retail value and it was not premised on renewable resources being dispatched by the utility, i.e., turned on or off depending on the wholesale cost of power ("LMP"). What UGI is proposing is to dis-incentivize – to roll back – the goals the legislation announced. The General Assembly used the term "Full Retail Value", not "retail rate" in the statute, and there is a reason. Full retail value is the full value of the power to a retail customer, and it is different from UGI's concocted GSR-2 default service rate. The energy that customers consume always has positive value. The utility bills a positive amount for the electricity it provides to other customers. What UGI is proposing is a modified wholesale rate that no other customer is paying for electricity – except by chance. This creates price volatility that in turn makes financing of small solar projects impossible.

Q. HOW DOES UGI CONFUSE DISTRIBUTION COSTS WITH GENERATION COSTS?

A. Distribution costs are the costs of operating the distribution system that delivers energy to customers, typically from interstate transmission lines, while generation costs are all of the costs of generating and delivering the energy to the distribution system. UGI has proposed to use the impact of a customer-generator on the distribution system, in the form of a proxy called Supply Peak Load Impact, a term that UGI invented for this proceeding, to classify and then to pay/charge customer-generators. There is no correlation between energy flow and the cost of operating the distribution system and so UGI's method is based upon a false assumption that UGI continues to promote in this proceeding.

Q. WHAT COMPONENTS OF UGI'S TREATMENT OF CUSTOMER-GENERATORS SHOW SIMILAR TREATMENT TO WHOLESALE GENERATORS?

A. First and foremost is the fact the that primary driver of the rate that UGI proposes for GSR-2 customers is the hourly PJM LMP. UGI intends that the volatility, a volatility that Mr. Faryniarz readily admits (UGI St. 2-R, 16:11), of that rate will necessarily cause customer-generators to attempt to react, and to dispatch their generation in response to a price signal rather than generating 100% of the energy they are able to produce each and every hour. That is the same behavior that one sees in wholesale generators. Another apt comparison is that wholesale generators are compensated for the commodity – the LMP – which is the same primary rate that drives the real time wholesale market, will be the primary driver of the compensation under UGI's proposal.

Q. HOW SHOULD CUSTOMER GENERATORS BE COMPENSATED FOR THE BENEFITS THEY PROVIDE TO A POWER DISTRIBUTION SYSTEM?

A. Under UGI's proposed plan, the sole method by which a customer-generator is compensated for the benefits they provide a power distribution system is the direct payment for excess generation above the customer's internal use. There are additional system benefits such as the value of having multiple sources of power distribution at various locations on the utility's system that improve reliability and availability of power supply that are valuable to customers. I have not proposed an additional payment to customer-generators for such benefits that they supply, however those benefits also demonstrate why "killing" nascent solar projects as UGI's proposed pricing plan will do, is clearly detrimental to its captive utility customers.

Even Mr. Faryniarz agreed that customer-generators do indeed provide such system benefits, stating "Different net metering facilities may have local system benefits or impacts – providing for improved or less reliability, lower system costs or more, and so on." (*id,* 29:9-11).

Q. WHAT INCORRECT STATEMENTS DOES MR. FARYNIARZ MAKE REGARDING HIS DESIRE TO CATEGORIZE CUSTOMER-GENERATORS BASED ON PEAK SUPPLY?

A. Mr. Faryniarz desires that the Commission forget the requirements of its own regulations. Mr. Faryniarz states that "Large customer-generators are appropriately classified as GSR-2 customers due to their general sophistication, likely impact on default service solicitations, and overall grid impact from a default service prospective." I disagree with

his statements. The first statement, that a customer's education or awareness level should be a rationale for an alternative rate, implies that Mr. Faryniarz believes that knowledge of a disadvantaged position indicates preference. Penn Renewables does not share Mr. Faryniarz's position. The fact that no solar generator under 3,000 kW is operating on the Pennsylvania wholesale market also shows that no generator of this size has preferred to enter the wholesale market. Furthermore, this implies that UGI believes a knowledge of market structures to be a better metric for segregating customer classes than peak load. This leads to nonsensical conclusions as evidenced by rhetorical questions as "does UGI propose that anyone with a knowledge of wholesale markets in their territory be placed onto GSR-2?" or "would lack of knowledge be a rationale to be placed back on to Full Retail GSR-1?" It should be that customers are segregated based on peak load not on their knowledge of market structures.

For the second argument, as far as the likely impact on default service solicitations, Mr. Faryniarz's view is also outside the borders of common logic. The last five years of deliveries on UGI's system have shown energy sales fluctuate up or down by up to 7-10% annually. UGI has stated that if ALL of the proposed projects are successful, it would only have an impact of 6% on their system. Distribution level solar arrays generally have a 50% or higher attrition rate during development. In fact, to date, all of the arrays that have requested use permits in UGI territory have been denied. Penn Renewables believes that a reduction in load of 3% or less would not have a significant impact on power supply price bidding behavior nor daily power dispatching activities to justify forcibly pushing a small set of unwanted customer-generators onto a disadvantaged wholesale rate unlawfully.

Retail choice also impacts the volatility and load profile of UGI default service, but UGI is not proposing to ignore laws and regulations governing consumer choice.

For the third argument, Mr. Faryniarz claims that small solar projects will have a negative cost impact on the grid, however this is not true because customer-generators will be paying for all studies, interconnections and upgrades related to attaching to the distribution system. This cost will not be borne by ratepayers. There will be a positive impact to the grid, and it will be to improve certain sections of the grid, at the cost paid for by customer generators. Finally, the last statement Mr. Faryniarz makes in this section of his testimony is "It is with this level of understanding and market access confidence that large customer-generators are best aggregated into the GSR-2 rate group". "Market access confidence" is a curious term. Penn Renewables is confident it could enter the UGI marketplace, only if the laws and regulations of the Commonwealth of Pennsylvania are upheld. Penn Renewables is aware that to date, no other generator of the proposed customers' size has chosen to enter the wholesale market in Pennsylvania. I am concerned that if UGI's proposed plan is successful in forcing small customer generators onto a disadvantaged rate, no amount of market knowledge will make those customer-generators enter the UGI marketplace.

Q. WHY SHOULD THE SIZE OF A CUSTOMER GENERATOR NOT BE A FACTOR USED IN DETERMINATION OF THE RATE IT WILL RECEIVE FOR POWER?

A. The AEPS Act allowed customer generators to be up to 3,000 kW under ordinary circumstances. All of Penn's projects are under that limit. As a general matter, power flows over a distribution system do not correlate to the cost of operating the system. Costs like tree trimming, facilities maintenance, etc. are not driven by the size of the loads they

serve. To the extent that the system needs additional transformation capacity or conductors to manage the interconnection of a customer generator, the customer- generator is charged for those upgrades to the utility distribution system. Therefore, the size of the generator does not increase the costs of distribution. UGI appears concerned with the prospect of 22 MW of generation coming on to its system, but based on historical experience, a substantial number of those projects may never be built or connected. More importantly, the generation of energy from a solar facility, while variable, is predictable insomuch as the sun rising and setting are predictable, so managing the generation should not be a burden for UGI. UGI should comply with the legislative mandate to incorporate these facilities into the distribution system. Lastly, UGI seems more concerned with the size of a customer-generator, not the volume of customer generator supply. If around 3% of UGI's customers (2,200) install a home solar system at 10 kW each, UGI would also have 22,000 kW, or 22 MW, or customer-generator supply on their system. However, these would all be charged at GSR-1. This demonstrates all arguments about supply impact onto the system are concocted.

Q. WHY IS MR. FARYNIARZ'S COMPARISON OF CUSTOMER-GENERATOR OUTPUT AND UGI'S LARGE CUSTOMER ENERGY CONSUMPTION NOT RELEVANT?

A. Physics dictates how the energy introduced into the distribution system will be consumed, i.e. power flows to the closest load first and then to the next closest load, and so on. Large customer consumption, relative to the source of the power that is consumed, is irrelevant to any discussion. Comparing customer-generator output relative to large customer

consumption as a justification for UGI's GSR-1 and GSR-2 groups is meaningless because it is a contrived classification invented as a basis for UGI's plan to disadvantage customer generators. If UGI were to allow the output of customer-generators to offset the usage of all customers without the artificial GSR-1 and GSR-2 classifications, the impact would be insignificant.

Q. WHY IS PAYING CUSTOMER-GENERATORS THE LOCATIONAL MARGINAL PRICE ("LMP") BOTH NOT PERMITTED BY STATUTE AND AN EFFECTIVE KILLER OF ANY AEPSA PROJECT?

A. The simple answer is that the AEPS Act requires that net metered customer-generators be paid at the full retail value. UGI's proxy rate that is based almost entirely on the LMP, which has none of the key features of a retail rate, and is not full retail value. The Full Retail Value GSR-1 PTC is an example of retail, as opposed to wholesale, value.

Q. WHAT ARE TYPICAL CONDITIONS THAT EXIST WHEN THE LMP IS NEGATIVE?

A. Typically, this occurs when local supply outpaces local demand. It can also be influenced by transmission constraints that do not allow for enough power to be exported to different load areas.

Q. WHAT CIRCUMSTANCES MUST EXIST FOR A SOLAR PROJECT TO BE PRODUCING POWER DURING A PERIOD WHERE THE LMP IS NEGATIVE?

A. If the generator is on GSR-2 it should not chose to produce power during a negative LMP – for obvious reasons. However, even not producing power when the price is negative requires active dispatch, which ***distribution level*** solar farms do not plan for, as well as knowledge of a price signal. In this case, the price an individual customer will receive is NOT known to them. While the LMP is posted on the PJM website, it is only one of many line items of UGI's proposed tariff. The true hourly price will not be known until weeks afterward. Distribution level net metered solar projects are generally not exposed to wholesale rates and thus, continue to operate regardless of LMP prices. Whereas large wholesale projects generally contract their supply out via a Power Purchase Agreement or a Financial of Physical forward sale, locking in their price for years into the future. Any hypothetical solar project that is operating with as much exposure to wholesale rates as UGI GSR-2 is proposing, would need to be monitoring the Day Ahead and real time power rates to self-curtail their power output. However, Penn Renewables' small solar systems are not designed for this type of operation and the extraordinary monitoring and management costs would be large and burdensome for such small systems. The AEPS guarantees full retail value for production, not frequent negative pricing. Under GSR-2, because the proposed rate is likely to frequently drop below the real time LMP price, a customer would be unable to know if a pricing would be negative in a given hour until the bill is sent the following month. That would be at a minimum of several weeks later. It is unclear how UGI expects a small customer to respond to an opaque price signal, except to not participate in the generation market at all.

Q. HOW LIKELY IS IT THAT A SOLAR PROJECT WILL BE CAPABLE OF PRODUCING POWER DURING A PERIOD WHERE THE LMP IS NEGATIVE?

Very likely if the negative LMP occurs during solar production hours.

Q. DOES THE OUTPUT OF A CUSTOMER-GENERATOR NEGATIVELY AFFECT DISTRIBUTION RATES?

A. No. As I discussed, distribution rates are not driven by the power flows on the lines, unless of course the flows change and require additional facilities. Because customer-generators are required to pay for any upgrades needed to mitigate the impacts of their interconnection, other customers receive a benefit from an upgraded distribution system at no cost to them, and distribution rates are not impacted. Small solar projects are price takers, cannot negotiate the price, and should be paid the same price that is charged to default service customers.

Q. IS MR. FARYNIARZ'S EXPLANATION OF UGI'S PROPOSED TREATMENT OF LOSS FACTORS REASONABLE?

A. No. Loss factors are commonly applied to power flows at the distribution and transmission level. However, the statute and the Commission's regulations require that customer-generators be compensated for each kilowatt hour metered, not adjusted up or down for losses.

Q. IS MR. FARYNIARZ'S EXPLANATION THAT UGI'S PRICING PROPOSAL DOES NOT DECREASE THE RATE PAID TO A CUSTOMER-GENERATOR AS OUTPUT INCREASE CREDIBLE?

A. No. While Mr. Faryniarz says that "UGI's rates do not decline" (*id.* 31:15) he then explains that it would be all the other components that would cause a decline in the payment to the customer-generator, stating, "PLC, NSPL, and MWh exports may change based upon customer actions" (*id.* 31:16). He is hoping we believe that it is not UGI's fault that the payments to a customer-generator decline, and that UGI is faultless. It is UGI's proposed compensation plan that categorizes customer-generators as GSR-2 that is directly responsible for such a decline in payment. His misdirection should be ignored. It is clear from **Exhibit JC-9** by replacing the values in line #1 and recalculating the formula, that the rate for a customer (either a non-customer-generator or a customer-generator) using 1000 kWh's of energy is far lower than a customer using only 100 kWh of energy.

Q. DOES THE STATUTE CITED BY MR. FARYNIARZ SUPPORT UGI'S PLAN TO BASE PAYMENT TO CUSTOMER-GENERATORS ON SPOT MARKET PRICING?

A. No. He said that "Section 2807(e)(3.2) further provides that "*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, [and] (iii) Long-term purchase contracts, entered into as a result of auction, request for proposal or bilateral contract… not greater than 21 years."* (*id.* 32:16-21). Even though Mr. Faryniarz claimed he cited the statute, he did not

cite it correctly. I reviewed Section 2807(e)(3.2)(i)-(iii) and found that Mr. Faryniarz's wording was incorrect. I include the section here completely without edit or omission:

> (3.2) The electric power procured pursuant to paragraph (3.1) shall include 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 an auction, request for proposal or bilateral contract that is free of undue influence, duress or favoritism, of more than four and not more than 20 years. The default service provider shall have sole discretion to determine the source and fuel type. Long-term purchase contracts under this subparagraph may not constitute more than 25% of the default service provider'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. This subparagraph shall not apply to contracts executed under paragraph (5).
> (3.3) The commission may determine that a contract is required to be extended for a longer term of up to 20 years, if the extension is necessary to ensure adequate and reliable service at least cost to customers over time.

Mr. Faryniarz cited this section for the proposition that it is permissible to categorize all of the purchases from customer-generators as spot market purchases. It is clear that UGI is not proposing to "purchase" power from customer-generators on or though the spot market, and it inappropriate to characterize UGI's scheme as a spot market purchase – the sales will not "clear" the PJM spot market. UGI may have tried to incorporate the spot market price as a proxy price for Full Retail Value, for the energy produced by customer-generators, but UGI is not purchasing energy from the customer-generators as a spot market purchase, in fact Ms. Hazenstab went to great lengths to note that the customer-generator will not need to register with PJM as a market participant. Indeed, because the primary purpose of the AEPS is to encourage development of alternative generation sources, any payment plan developed by a utility should support such intent. UGI's plan does not and should be changed as I have recommended to achieve the goal of AEPS.

Q. WHAT COMMENTS DID MS. HAZENSTAB MAKE THAT YOU OBJECT TO?

A. In my direct testimony I explained that UGI was dragging their feet in supporting timely development of solar projects, and specifically the projects of Penn Renewables. Ms. Hazenstab (Statement 2-R, p2-3) claims that timely compliance is not a requirement "The timelines mentioned in Mr. Crist's testimony of 90 to 120 days are not prescribed requirements" (*id*. 2:9-10) and that it does not conduct the engineering reviews itself but instead retained a contractor to do so "UGI Electric has contracted with an outside firm for this work as the Company does not maintain in-house expertise or the necessary engineering models to conduct the required analysis that is necessary to allow for the safe interconnection" (*id*. 3:14-16). Her statement is troubling for two reasons. First, I am concerned by her admission that UGI does not have expertise to evaluate and understand safe interconnection, and second that it is implied that it is not UGI's fault, but the fault of the contractor dragging their feet. It is my second concern that I will address here. While UGI might have all the time in the world to evaluate a project and apparently feels no sense of urgency to do so, such is not the environment facing a small solar project developer. Penn Resources does not have unlimited funds and receives no revenue until a project is actually built and producing electricity. For such small business, time is of the essence, and UGI's complacency is troubling.

Because Ms. Hazenstab promised "Completion of the engineering models by September 14, 2024." I issued a data request for such model to check if the contractor was actually on schedule. I learned that indeed, the engineering studies yet again were not completed as promised and there is no expected date for their completion. UGI's response is included as **Exhibit JC-12**.

Q. WHAT IS WRONG WITH MS. HAZENSTAB'S DEFENSE OF THE COMPANY'S USE OF SUPPLY PEAK LOAD IMPACT ("SPLI") AS THE FACTOR THAT DETERMINES WHETHER A CUSTOMER-GENERATOR IS CATEGORIZED AS GSR-1 OR GSR-2?

A. First, I disagree with Ms. Hazenstab's claim in her testimony that Penn's 2,000 kW projects are "large" – they are not. I am aware that the FERC classifies generation projects under 20 MW as small, so at 2,000 kW, Penn's projects are small indeed. I also suggest that for Ms. Hazenstab to claim that the size of a customer's "load" for purposes of the Commission's Regulations is not relevant to this proceeding is simply wrong. The maximum registered peak load is still "peak load", not "system impact" and the regulation is clear that the Company's SPLI is not a measure of peak load or peak load contribution, and it does not comply with the definition. UGI is making up terms and definitions and suggesting them as substitutes for terms that are defined in regulations. SPLI is not load and is not sanctioned by the regulations.

Q. DOES MS. HAZENSTAB'S REASONING OF WHY A CUSTOMER-GENERATOR SHOULD NOT BE PERMITTED TO SELECT WHICH CUSTOMER CLASS IT IS SERVICING MAKE SENSE?

A. No. I am advised by Counsel that the Public Utility Code requires that if a utility has more than a single rate class that might apply to a customer, that it must place the customer on the most beneficial rate to the customer if the customer chooses that rate. Because customer-generators are small business customers, they would be served under Rate GS-4,

by definition, UGI is required to allow them to be Full Retail GSR-1 customers, and yet UGI has refused to do so.

Q. WHY DID MS. HAZENSTAB DISAGREE THAT THE GSR-2 THRESHOLD SHOULD NOT BE CHANGED FROM 25 kW TO 3000 kW TO ALLOW MORE CLIMATE-FRIENDLY CUSTOMER-GENERATORS?

A. Ms. Hazenstab gives many reasons for this. First, that "customer-generators have significant and material difference to an EDC distribution system and supply management activities." Statement 3-R 3:17-18. Second, that there is "no discussion or consideration related to large customer-generators with material generation capability (say 1 MW and above) but having low power consumption characteristics being qualified as a small customer" *id.* 3:21-23. Third, "specific and highly sophisticated engineering models, feasibility studies, system impact studies and facility studies are needed for such installations and require a significant amount of time and effort" *id*.4:2-4.

These three arguments do not hold water. Ms. Hazenstab does not address the obvious fact that any studies, interconnection costs and network upgrades are borne by the interconnecting customer. This is specifically so that the other customers of the system are not responsible for the addition of new customers. Penn Renewables has already affirmed and requested invoices for the first batch of studies, but they have not yet been delivered by UGI.

Ms. Hazenstab continues with three additional arguments. Fourth, that "the Commission has already recognized that customers with load impacts of 100 kW and greater should be considered in a separate default service group as part of UGI Electric's current DSP IV

plan." *id.* 4:8-10. Penn Renewables understands that best industry practice is to segregate customers by load, not supply, as electric power systems are built to satisfy maximum coincidental demand and a systems' costs are best allocated based on coincident peak demand. However, new supply added onto the system does not have the same impact to the system as new load added to a distribution system. In many ways, new supply additions reduce system utilization and reduces that maximum demand. Because any system upgrades required are paid for by the customer-generator, the argument that system costs should be based on peak supply is completed illogical and should be rejected.

Ms. Hazenstab makes a fifth argument that Penn Renewables proposed customers are "Utility Scale" because the Energy Information Administration ("EIA") defines Utility Scale as 1,000 kW or greater. I note that the article Ms. Hazenstab referenced for her argument also contains the following language *"Currently, North Carolina has 433 utility-scale PV facilities with capacities no greater than 5 MW, the most of any state, and accounting for nearly a quarter of all utility-scale PV facilities in the country between 1 MW and 5 MW. These facilities collectively account for 1,803 MW of capacity, or 35% of the total U.S. PV capacity located at facilities with 1 MW to 5 MW of installed capacity.*" And "*The growth in small utility-scale facilities is driven by several factors, many of which are tied to state-level policies and practices. For example, North Carolina used the Public Utilities Regulatory Policies Act of 1978 to allow utilities to set long-term purchase agreements with solar facilities, enabling solar developers to secure project funding more easily and spurring growth.*" Penn Renewables sees this as further evidence of the argument that 1,000 to 5,000 kW systems can only realistically be developed under stable, retail level prices that are driven by state laws such as North Carolina's use of the PURPA

or Pennsylvania's AEPS. In any case, the EIA's definition of "utility scale" is not applicable in determining if this proposed tariff complies with Pennsylvania laws and regulations.

Sixth, starting on page 4, line 20 of her testimony, Ms. Hazenstab discusses the maximum 25 kW peak load requirement for small business customers, a category of which Penn Renewables' potential customer-generators currently fall into. Ms. Hazenstab defines "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 EDC tariff in a particular service territory." Ms. Hazenstab then requests a waiver to reduce this 25-kW requirement, however, does not propose a new limit for the definition of small business customers. It is UGI's assumption in multiple submissions that it believed any customer-generator would have a PLC value of zero. This is noted as an assumption in its response to PENN-III-8 which states: "Assumes PLC value of zero (net generation during all PLC hours) for customers with usage of 100 kWh, (1,000) kWh, (100) kWh & (200) kWh". Penn Renewables itself expects a maximum PLC or Peak Load value of 2-5 kW but finds it also likely for the PLC value to be zero kW if the arrays are generating during PLC hours, which is a reasonable expectation and one that I share with UGI. It is confusing that UGI might be implying or suggesting that it would request to define in its tariff a value of 0 kW for PLC or Peak Load for a small business customer. This would categorically eliminate the small business class in UGI's territory, and also would harm the existing group of small business customers, only to continue to pursue unfair treatment of a small group of unwanted customer generators.

Q. WHAT IS YOUR REACTION TO UGI'S REQUEST, IN ITS REBUTTAL TESTIMONY, FOR A WAIVER OF THE COMMISSION'S REGULATIONS AT 52 Pa Code § 54.187(h)?

A. UGI's request should be denied. If such a waiver is granted it creates another huge issue. Removing the requirement that small business customer rates not be changed more frequently than quarterly would take away a protection of rate stability for those customers that has been in the regulations since they were promulgated, because the Commission understands that small business customers do not have the wherewithal to manage constantly fluctuating rates. The waiver would remove this protection for all customers under 25 kW registered peak load, which includes residential customers as well. That UGI was not aware that its proposal violated this provision is also troubling. What is more troubling is that UGI cavalierly asks, mid-proceeding, for the ability to vary at will the period for which a default service rate is effective, for any customer under 25 kW registered peak load. UGI fails to address the fact that the proposal also violates the requirement of § 54.187(c) which requires that customers be provided with a single rate option – the PTC – which shall be displayed as a line item on a customer's bill. UGI's "change every hour" rate for GSR 2 customers violates this provision as well.

Q. IS MS. HAZENSTAB'S CLAIM THAT THE RATE UGI PROPOSES FOR GSR-2 IS A RETAIL RATE CORRECT?

A. No. The rate does not include the rate components that are typical of a retail rate, such as load following, etc. Rather, the rate is almost entirely the same as the LMP, which is a wholesale rate.

Q. WHAT IS MS. HAZENSTAB'S RESPONSE TO YOUR CLAIM THAT THE RATE UGI PROPOSES FOR GSR-2 IS NOT A DEFAULT SERVICE RATE?

A. She has no response other than to say that there are other variable rate default service rates. That may be true but there are no mandatory variable rates that she can cite to that are based directly on the hourly LMP. While the LMP does vary, it does not adhere to the requirements for variable rates, for example, there is no limit on the degree of variability (and it can be negative or positive). Variable default service rates are not the same as the LMP, and Ms. Hazenstab does not point to a single example to the contrary.

Q. WHY IS UGI'S PROPOSED GSR-2 RATE NOT A STABLE RATE?

A. It is not stable because it is driven by the LMP and the hourly change in the price of electricity. **Exhibit JC-10** demonstrates the variability of the GSR-2 rate using a technique called back-casting, which uses actual data combined with UGI's Attachment PENN-III-8 to determine what the GSR-2 rate would have been over the past 3.5 years. The GSR-2 Rate, which is the rate that customer-generators would be paid under UGI's proposed plan, decreases simultaneously with the increase in production, and increases as production decreases. This means in the hours where customer-generators are contributing the most energy, they are being paid the least per unit. UGI's proposed plan is designed to be a complete disincentive to customer-generators that will result in the absence of alternative energy projects and not fulfill the desires of the AEPS Act.

Q. WHY IS UGI'S PROPOSED GSR-2 RATE NOT THE SINGLE RATE OPTION THAT IS REQUIRED?

A. While the term "single rate option" is not defined in the Commission's regulations, the regulations do equate the single rate option with the PTC and require that it be displayed as a line item on the customer's bill. All the regulations that apply to a PTC apply to a single rate option, including the variability restrictions of Section 54.187(h). The clear intent of the Price to Compare is to show a customer which price they are paying so they can compare it to alternative providers. Default service is supposed to be transparent and predictable. The proposed construct would yield generally 744 different prices in EACH MONTH with 31 days, slightly less for shorter months. Every hour for every customer will result in a different price. This is not a single rate. It might be an identical calculation, but the rate varies and will not be known for a given hour until the bill arrives with 700+ lines. According to 52 Pa. Code § 54.187. "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." The letter of this regulation states that the PTC be displayed as a line item, not item**s**. UGI is proposing that more than 700-line items are the same as a single line item. UGI has not explained how the PTC-2 will be published as it will be different for every hour for every customer.

Q. WHAT RATE SCHEDULE IS MOST APPLICABLE TO PENN RENEWABLE'S SOLAR PROJECTS?

A. Rate GS-4 provides for a minimum billing demand of not less than five kW, and most of PENN's projects are 10 kW most of the time. Generation supply service surcharge Rider

B applies to GS-4. Rider B applies GSR-1 pricing where the customer's annual peak load is less than 100 kW.

Q. DOES UGI'S PROPOSED PLAN PROVIDE FAIR COMPENSATION AT YEAR END FOR A CUSTOMER-GENERATOR'S EXCESS KWH?

A. No. The AEPS law requires a "kWh for kWh" crediting and gives a clear example. There is no mention or allowance for a dollar for dollar crediting where one kWh is not equal to another. Ms. Hazenstab appears to be confusing terminology from the AEPS with the Public Utility Code and the Commission's Regulations. The term "customer-generator" from AEPS is very clear that a customer=generator is both a customer and a generator. As a customer, the rules that apply to a customer of their size apply to them, as do the rules under the AEPS, as I am advised by Counsel. Contrary to Ms. Hazenstab's assertion, customer-generators do have the obligation and protection of the Commission's rules that apply to customers, otherwise UGI's entire proposal, that relies on selective and incorrect reading of the regulations, would not apply, because if customer=generators are not customers, the regulations would not apply. As customers, the classes are determined by Registered peak demand, and based on their peak demand, customers where PENN has a project will have less than 25kW of demand. It does not matter, per section 54.187(h) if Penn Renewables is a small business (which it is) or not, the customers' peak load is less than 25 kW. The regulations do not reference SPLI, and it is clear that SPLI is not the same as registered peak load.

Q. DOES UGI'S PROPOSED PLAN PROVIDE CUSTOMER-GENERATORS FAIR COMPENSATION AT FULL RETAIL VALUE?

A. No. As I have noted elsewhere, retail value is not defined in the AEPS, but the Commission's Regulations do attempt to quantify it as including generation, transmission and distribution charges. UGI's proposed compensation scheme does not comply. UGI's proposed plan does not comply with both the letter and spirit of the law for several reasons:

1. Using Attachment PENN-III-8 as a guide, in all cases, for hours where the customer is a "load" the rate is far higher than the Full Retail GSR-1 rate as well as the GSR-2 rate if the customer was in a state of "supply". The intent and letter of the law is that energy is netted out and refunded at a constant rate, where timing of supply/consumption should be non-impactful. The law specifies that energy is netted out kWh for kWh, and then refunded. The proposal creates a system where some kWh's are far more valuable than other kWh's depending primarily if they are being supplied or consumed, and also depending on the time of consumption or production, at a time when these same produced kWh's are being re-sold to other customers on the same line for a much higher Full Retail Value GSR-1 rate.

2. If the customer-generator is supplying at all hours of PLC and NSPL, a realistic scenario if a storage device is added to a customer-generator, there will be no charges or refunds or compensation for capacity and most transmission charges. The AEPS law requires this.

3. In Virtual Net Metering, multiple customer meters can be grouped together and net metered if they are uniformly owned and in close proximity. In the occurrence where both LMP prices and GSR-2 prices are negative, under UGI's proposal this would

result in the customer having one meter under GSR-1 being charged for consuming energy while the other meter under GSR-2 being charged for supplying energy. There is no kWh for kWh netting, even though the AEPS requires it. This does not provide any netting or offsets in UGI's hourly variable rate structure, since both meters incur charges. Full Retail Value is not being offered to the generator.

Q. WHY DOES UGI'S PROPOSED PTC NOT PROVIDE CUSTOMER-GENERATORS FAIR COMPENSATION OF ALL DEFAULT SERVICE COSTS?

A. If the customer-generator is supplying at all hours of PLC and NSPL, which is a realistic and feasible scenario especially if a storage device is added to a customer-generator, there will be no charges or refunds or compensation for capacity and most transmission charges. The AEPS law requires this. If UGI proposed allowing these parameters to be measured as a "negative" in their rates, operationally it would lower the GSR-2 rate in every hour. As this acts as a "crediting" rate in the GSR-2 construct, it would effectively be penalizing a customer-generator for supplying energy and capacity at these hours of highest grid constraint.

Furthermore, production during these most grid constrained hours within the UGI system would result in lower costs to all customers of UGI. These lower cost impacts would be reduced for all UGI customers… except of course the customer-generators responsible for creating the value.

Q. WHAT IS INCORRECT WITH MS. HAZENSTAB'S CLASSIFICATION OF SMALL BUSINESS CUSTOMERS?

A. Ms. Hazenstab continually refers to customers having a peak load of 25 kW to 500 kW. Penn Renewables expect each of its customer-generators to have a peak load of less than 10 kW, which is below the 25 kW value that Ms. Hazenstab is concerned about. A 10 kW peak load customer would not fall into the 25 kW to 500 kW bracket. Ms. Hazenstab's comments are not applicable to Penn Renewables' potential customers. Secondly, UGI acknowledges that customers with a 10 kW peak load would not be eligible for the variable wholesale GSR-2 rate, and thus proposed a waiver of the 25 kW limit for small business customers to be reduced for purposes of rate variability, but has not offered to match the kW limit for the SPLI construct. This further illustrates that this entire construct is to obstruct law and regulations to dissuade a small group of unwanted customers.

Q. WHAT COMMENTS DID MR. OGUR MAKE THAT YOU OBJECT TO?

A. Mr. Ogur disagrees that the classification of customers into GSR-1 and GSR-2 procurement groups be made based exclusively on a customer's peak demand. He also contests the position that the threshold for an account to be classified as GSR-2 be raised from 100 kW to 3,000 kW if the Commission authorizes UGI to compensate GSR-2 customer-generators based on LMP. I will address each of his objections.

Q. WHY SHOULD CUSTOMERS BE CLASSIFIED INTO PROCUREMENT GROUPS BASED ON THEIR PEAK DEMAND?

A. Electrical systems are designed and built to satisfy peak demand of the system. The costs for developing, and building a system are mostly fixed, including both invested capital and a fairly steady and predictable amount of O&M with little sensitivity or correlation to power flows over the system. O&M investment for electric delivery is mostly based on maintenance intervals, vegetation growth, preventative maintenance and storm damage, not on incremental changes in power flows. Thus, peak load requirements are an effective tool for allocating system costs. Supplying customers, especially those who pay for their own interconnection costs and any required network upgrades, impose few operational costs onto a system, but also reduce demand on a system in times of greatest constraint. They help the system, not burden. Peak demand, not system impact, is a far better cost allocation methodology. This is evidenced by every other electrical utility and system in the Commonwealth utilizing demand, not system impact as their billing determinant.

Q. WHY SHOULD THE CLASSIFICATION THRESHOLD FOR CUSTOMER-GENERATORS BE RAISED FROM 100 KW TO 3,000 KW IF THE COMMISSION AUTHORIZES UGI TO COMPENSATE CUSTOMER-GENERATORS BASED ON LMP?

A. The AEPS act utilized the 3,000 kW limit for a reason. This is the limit they decided was best for small customer-generators to apply into the net energy metering construct. It is the spirit of the law that 3,000 kW is a small generator and above that a large generator. There are no generators smaller than 3,000 kW operational in the Pennsylvania wholesale market today.

Q. WOULD YOUR PROPOSED CHANGES BENEFIT RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS?

A. Yes. It will allow such customers to operate as customer-generators and receive the GSR-1 pricing for their excess power. Residential and small commercial customers will be able to engage in net metering with small solar projects and reduce their electric bill, while taking positive action to reduce the impact of climate change.

Q. WHAT IS THE SUMMARY OF YOUR SURREBUTTAL TESTIMONY?

A. The critical point that captures the issues discussed is that the small alternative energy project, such as the solar projects being analyzed by Penn Renewables should have surplus energy credited at the GSR-1 rate, which applies to 99% of UGI's load. UGI's effort to compensate energy from such projects at the low, variable, unpredictable GSR-2 rate will result in a dearth of projects being developed. A Commission Order directing UGI to compensate net metered customer generators at the GSR-1 rate is necessary to enable any small net metered project development.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

EXHIBIT JC-8

Question 14

Request:

Regarding the language of the regulation, "An EDC and 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." Produce a table portraying calculated GSR-1, GSR-2 monthly average rates for the historic period 6/2021-6/2024 and forecast rates for the period 7/2024 through 5/2029. Explain basis of forecast pricing.

Response:

Please see Attachment PENN-III-14 for historic period rates.

The forecasted rate for GSR-1 customers for the quarter-beginning September 1, 2024 is $0.11064/kWh. The forecast is based on projected costs with a true-up of experienced cost and revenue, as outlined in UGI Electric Tariff No. 6, pages 39 - 40. Forecasts are not available for other future periods.

UGI Electric does not forecast rates for GSR-2.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Electric Division
Historic Monthly Default Service Rates ($/kWh)
June 2021 - June 2024

	GSR-1	GSR-2*
Jun-21	0.06331	0.04613
Jul-21	0.06331	0.03987
Aug-21	0.06331	0.07744
Sep-21	0.06218	0.07496
Oct-21	0.06218	0.07041
Nov-21	0.06218	0.08575
Dec-21	0.09005	0.07920
Jan-22	0.09005	0.06662
Feb-22	0.09005	0.07336
Mar-22	0.08853	0.07028
Apr-22	0.08853	0.07566
May-22	0.08853	0.08799
Jun-22	0.12902	0.10316
Jul-22	0.12902	0.10330
Aug-22	0.12902	0.10995
Sep-22	0.12902	0.13449
Oct-22	0.12902	0.09455
Nov-22	0.12902	0.08026
Dec-22	0.12902	0.08012
Jan-23	0.12902	0.14616
Feb-23	0.12902	0.05827
Mar-23	0.12539	0.05352
Apr-23	0.12539	0.05126
May-23	0.12539	0.05956
Jun-23	0.11083	0.04790
Jul-23	0.11083	0.04701
Aug-23	0.11083	0.05266
Sep-23	0.12128	0.04456
Oct-23	0.12128	0.04736
Nov-23	0.12128	0.05570
Dec-23	0.10260	0.05883
Jan-24	0.10260	0.05148
Feb-24	0.10260	0.05869
Mar-24	0.09978	0.04364
Apr-24	0.09978	0.04523
May-24	0.09978	0.05167
Jun-24	0.10525	0.05438

*GSR-2 Rates were calculated by taking billed revenue divided by billed sales.

EXHIBIT JC-9

Question 8

Request:

Please add columns on Attachment Penn I-2

a. to include an example for a comparable non-generating GSR-2 customer of similar 1,000 kW load;

b. that demonstrates the PTC if the customer generator, assuming all other factors remain the same, is producing at 100 kw in a given hour; and

c. that demonstrates the PTC if the customer generator is producing at 200 kw in a given hour.

Response:

Please see Attachment PENN-III-8.

Prepared by or under the supervision of: James M. Rouland

UGI UTILITIES, INC. – ELECTRIC DIVISION
GSR-2 CUSTOMER PRICE TO COMPARE EXAMPLE CALCULATION

Line #	Line Item Description for GSR-2 Customer	Example of Hour Net Consumption (kWh)	Example of Hour Net Generation (kWh) /D	Example of Hour Consumption (kWh) Non-Customer Generator	Example of Hour Net Generation (kWh) /D	Example of Hour Net Generation (kWh) /D
1	kWh (metered value)	100	(1,000)	1,000	(100)	(200)
2	Applicable hourly EHV Loss percentage (from PJM)	0.6%	0.6%	0.6%	0.6%	0.6%
3	Total loss percentage with inclusion of 6.5% UGI system loss (L2+6.5%)	7.1%	7.1%	7.1%	7.1%	7.1%
4	Loss gross up factor (1-L3)	92.9%	92.9%	92.9%	92.9%	92.9%
5	Grossed up kWh for losses (L1/L4)	108	(1,076)	1,076	(108)	(215)
6	Applicable hourly deration factor (from PJM)	3.9%	3.9%	3.9%	3.9%	3.9%
7	Deration factor (1-L6)	96.1%	96.1%	96.1%	96.1%	96.1%
8	kWh (with deration) (L5*L7)	103	(1,034)	1,034	(103)	(207)
9	LMP ($/MWh)	$ 40.0000	$ 40.0000	$ 40.0000	$ 40.0000	$ 40.0000
10	LMP ($/kWh) (L9/1000)	$ 0.0400	$ 0.0400	$ 0.0400	$ 0.0400	$ 0.0400
11	Total LMP charges (L8*L11)	$ 4.1378	$ (41.3778)	$ 41.3778	$ (4.1378)	$ (8.2756)
12	PJM allocated charges - PLC based ($/kW) /A	$ -	$ -	$ 0.2597	$ -	$ -
13	PJM allocated charges - NSPL based ($/kW) /B	$ 0.6375	$ 0.6375	$ 1.2750	$ 0.6375	$ 0.6375
14	PJM allocated charges/(credits) - kWh based ($/kWh)	$ (0.0076)	$ (0.0076)	$ (0.0076)	$ (0.0076)	$ (0.0076)
15	Total PJM allocated charges/(credits) - kWh based (L8*L14)	$ (0.7862)	$ 7.8618	$ (7.8618)	$ 0.7862	$ 1.5724
16	DSP A&G allocated costs - kWh based ($/kWh)	$ 0.0070	$ 0.0070	$ 0.0070	$ 0.0070	$ 0.0070
17	Total DSP A&G allocated costs - kWh based (L8*L16)	$ 0.7241	$ (7.2411)	$ 7.2411	$ (0.7241)	$ (1.4482)
18	Net Metering Purchase Reconciliation /C (charge/(credit)*L8) ($/kWh)	$ -	n/a	$ -	n/a	n/a
19	Total GSR-2 (L11+L12+L13+L15+L17+L18) excluding GRT	$ 4.7132	$ (40.1197)	$ 42.2919	$ (3.4382)	$ (7.5139)
20	Total GSR-2 charges including GRT (L19/(1-5.9%))	$ 5.0087	$ (42.6351)	$ 44.9435	$ (3.6538)	$ (7.9850)
21	STAS (currently 0%)	0.00%	0.00%	0.00%	0.00%	0.00%
22	Total PTC-2 (L20*(1+L21))	$ 5.0087	$ (42.6351)	$ 44.9435	$ (3.6538)	$ (7.9850)
23	Unit PTC-2 (per kWh) (L22/L8)	$ 0.0484	$ 0.0412	$ 0.0434	$ 0.0353	$ 0.0386

/A - Assumes PLC value of zero (net generation during all PLC hours) for customers with usage of 100 kWh, (1,000) kWh, (100) kWh & (200) kWh and a PLC of 100 kW for customer with usage of 1,000 kWh.
/B - Assumes NSPL value of 50kW (net consumption on 50% of NSPL hours) for all scenarios except for customer with usage of 1,000 kWh which utilizes an NSPL value of 100kW (indicative of 100kW load during all NSPL hours).
/C - Assumes no current reconciliation charges/(credits)
/D - Values shown in Line 1 for generating customers are representative of net production over an hourly period

EXHIBIT JC-10

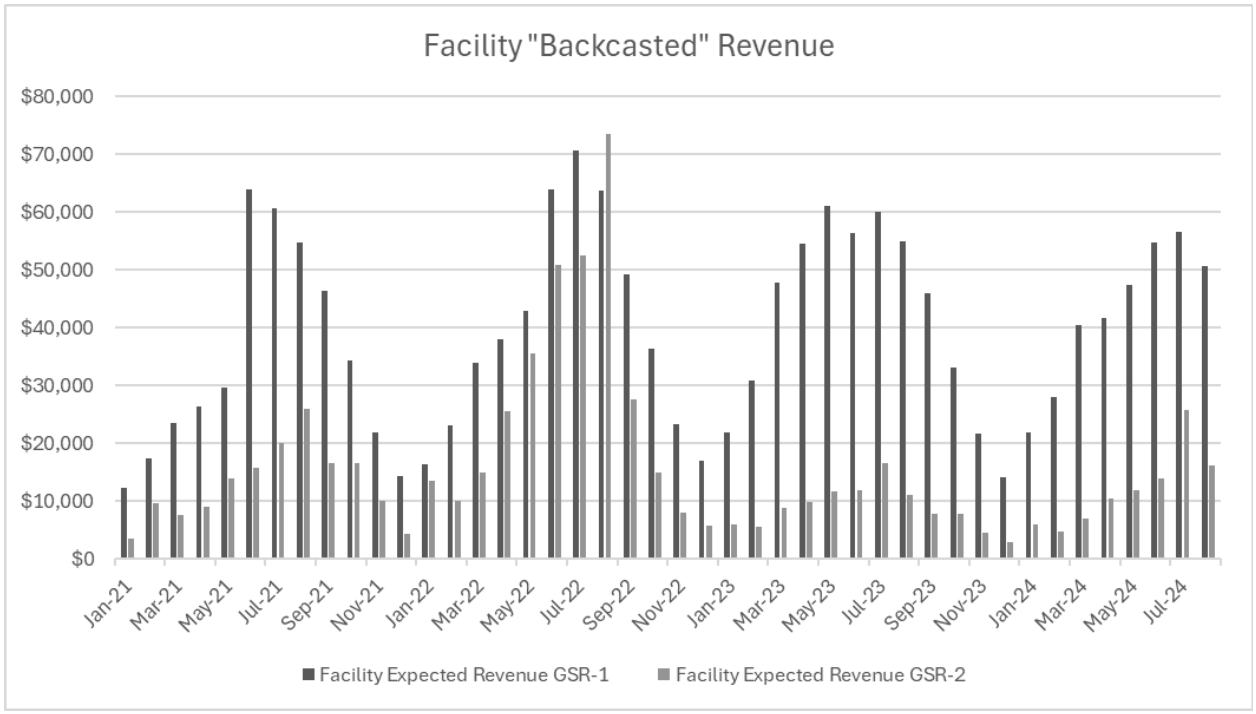
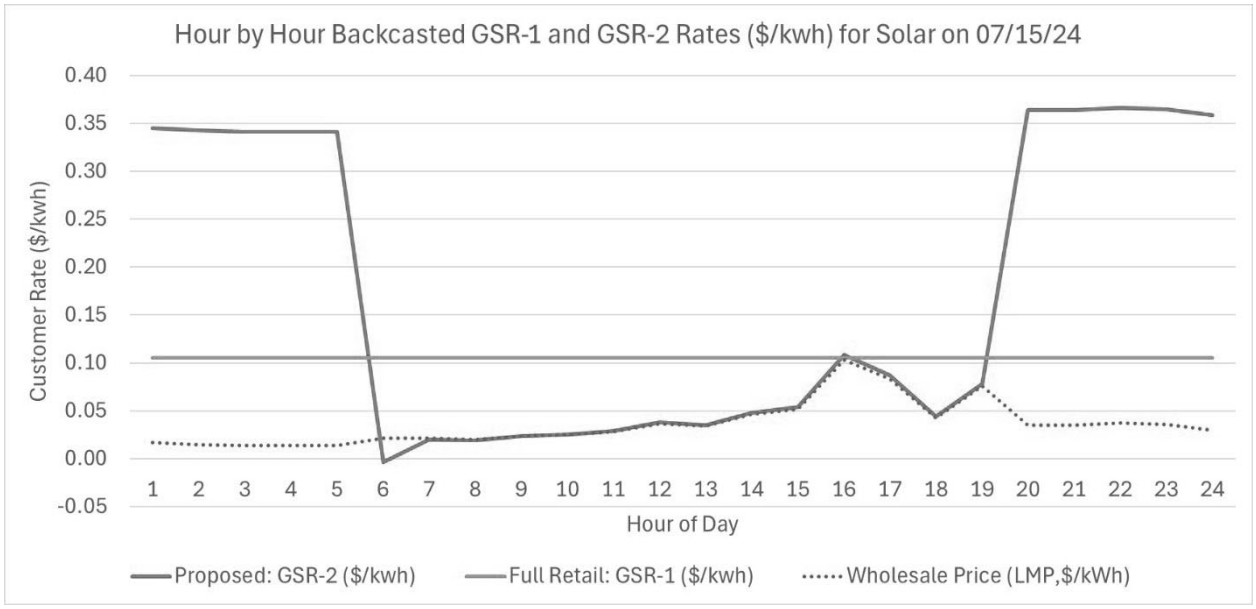
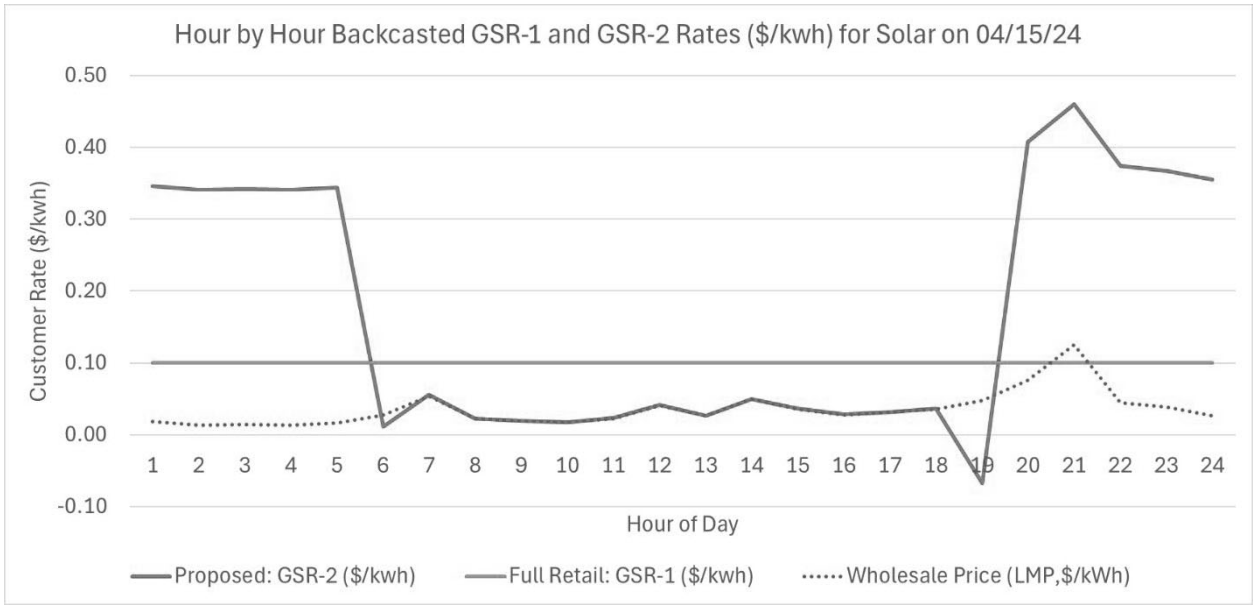
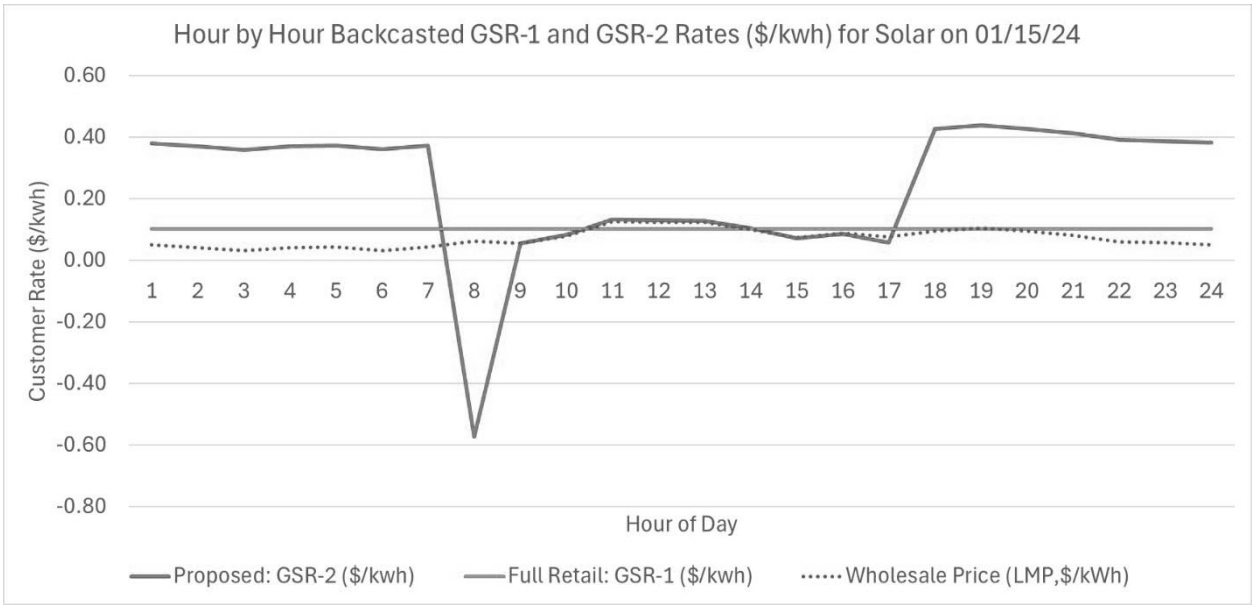
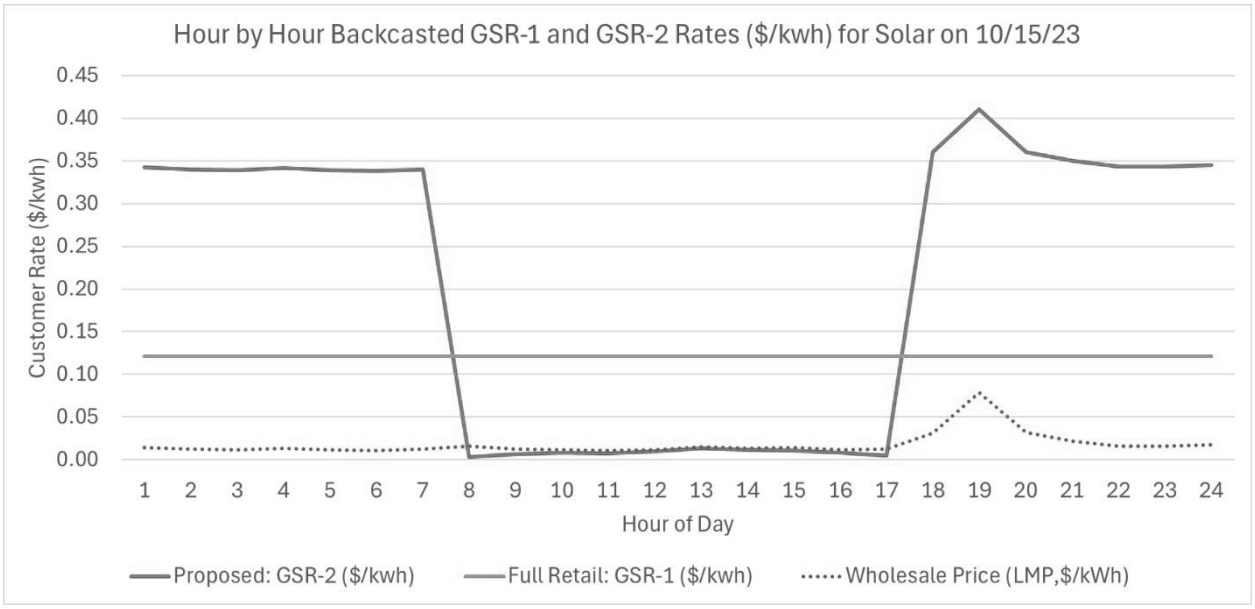

Facility "Backcasted" Revenue
$80,000
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
Jan-21
Mar-21
May-21
Jul-21
Sep-21
Nov-21
Jan-22
Mar-22
May-22
Jul-22
Sep-22
Nov-22
Jan-23
Mar-23
May-23
Jul-23
Sep-23
Nov-23
Jan-24
Mar-24
May-24
Jul-24
Facility Expected Revenue GSR-1
Facility Expected Revenue GSR-2

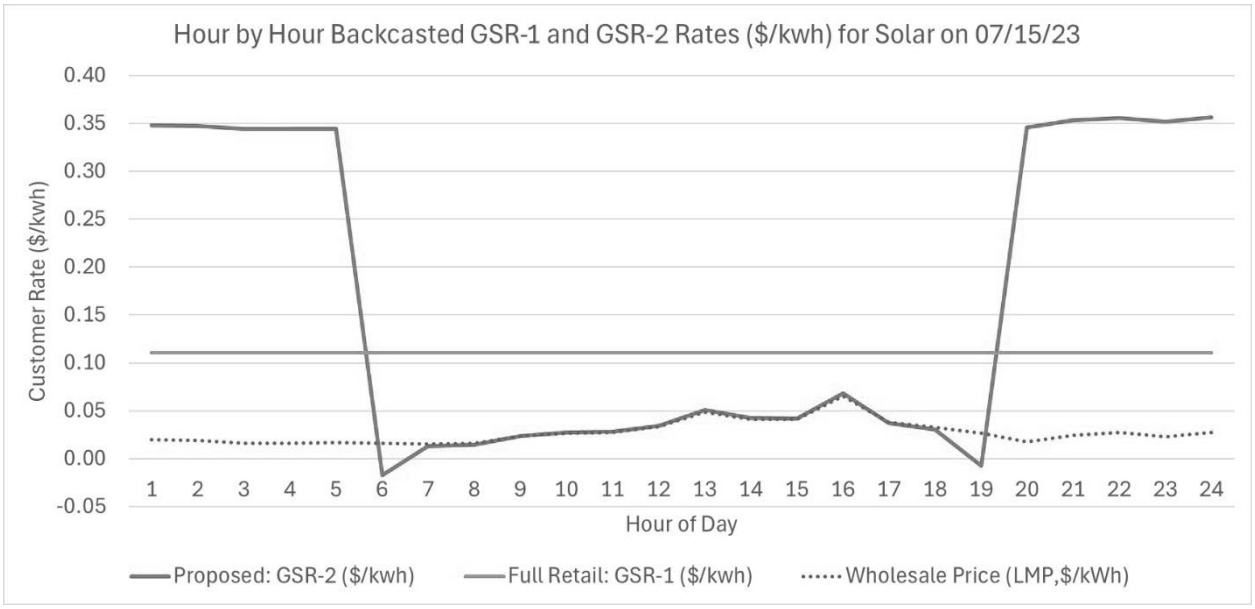
EXHIBIT JC-11


Hour by Hour Backcasted GSR-1 and GSR-2 Rates ($/kwh) for Solar on 07/15/24
Customer Rate ($/kwh)
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
-0.05
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour of Day
Proposed: GSR-2 ($/kwh)
Full Retail: GSR-1 ($/kwh)
Wholesale Price (LMP,$/kWh)


Hour by Hour Backcasted GSR-1 and GSR-2 Rates ($/kwh) for Solar on 04/15/24
Customer Rate ($/kwh)
0.50
0.40
0.30
0.20
0.10
0.00
-0.10
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour of Day
Proposed: GSR-2 ($/kwh)
Full Retail: GSR-1 ($/kwh)
Wholesale Price (LMP,$/kWh)


Hour by Hour Backcasted GSR-1 and GSR-2 Rates ($/kwh) for Solar on 01/15/24
Customer Rate ($/kwh)
0.60
0.40
0.20
0.00
-0.20
-0.40
-0.60
-0.80
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour of Day
Proposed: GSR-2 ($/kwh)
Full Retail: GSR-1 ($/kwh)
Wholesale Price (LMP,$/kWh)


Hour by Hour Backcasted GSR-1 and GSR-2 Rates ($/kwh) for Solar on 10/15/23
Customer Rate ($/kwh)
0.45
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour of Day
Proposed: GSR-2 ($/kwh)
Full Retail: GSR-1 ($/kwh)
Wholesale Price (LMP,$/kWh)


Hour by Hour Backcasted GSR-1 and GSR-2 Rates ($/kwh) for Solar on 07/15/23
Customer Rate ($/kwh)
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
-0.05
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour of Day
Proposed: GSR-2 ($/kwh)
Full Retail: GSR-1 ($/kwh)
Wholesale Price (LMP,$/kWh)

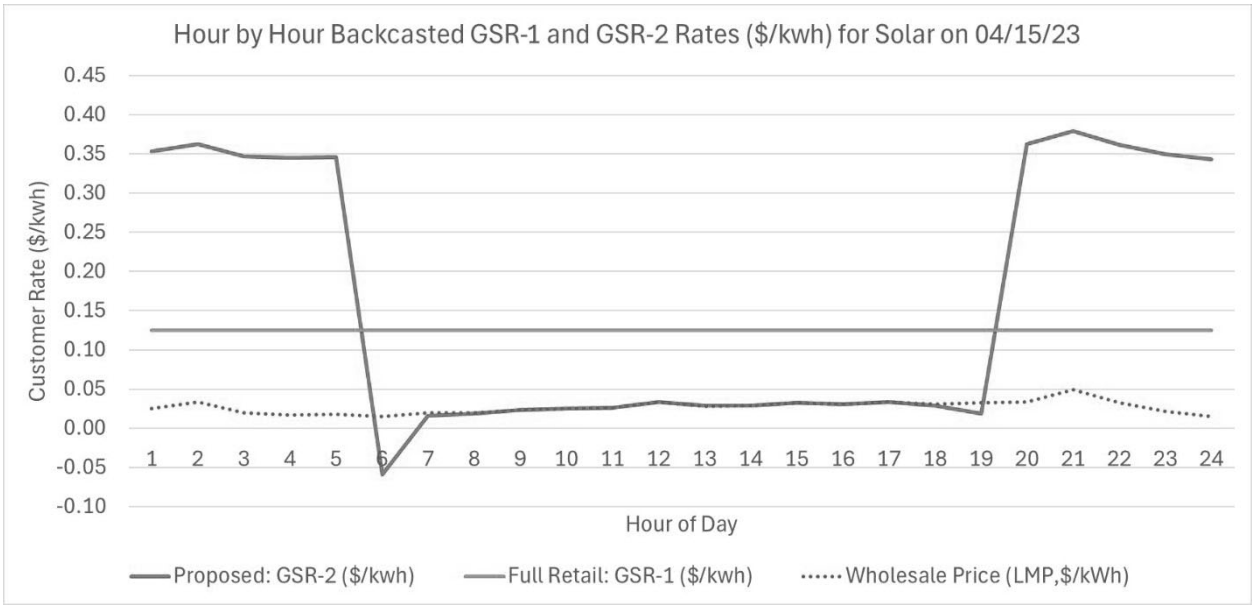

Hour by Hour Backcasted GSR-1 and GSR-2 Rates ($/kwh) for Solar on 04/15/23
Customer Rate ($/kwh)
0.45
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
-0.05
-0.10
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour of Day
Proposed: GSR-2 ($/kwh)
Full Retail: GSR-1 ($/kwh)
Wholesale Price (LMP,$/kWh)

EXHIBIT JC-12

UGI Utilities, Inc. - Electric Division
Docket No. P-2024-3049343
UGI Electric Default Service Plan
Responses to Penn Renewables Set VI (1-4)
Delivered on September 23, 2024

Question 1

Request:

On page 2 of her Rebuttal Testimony, Ms. Hazenstab discussed the schedule for review of Penn Renewables Projects. She claimed that the schedule included "Completion of the engineering models by September 14, 2024." Provide a copy of the entire engineering model developed by UGI's contractor as described in Ms. Hazenstab's testimony. Identify the date the model was provided to UGI and provide the model. Also provide any internal communication regarding the approval of the Penn Renewables Projects.

Response:

UGI Electric and Penn Renewables agreed to the following revised request: "In lieu of the model requested in Penn Renewables Set VI No. 1., we will accept the following: a summary of the inputs and outputs of the model and including the purpose and general function for the model." UGI's consultant is developing a model of its distribution system based on known UGI system parameters:

- Substation Transformer Sizes and Voltage
- Substation Circuit breakers
- Substation Feeder Relay Protection
- Distribution Pole Information
    - Height
    - Construction
        - Dead-end
        - Tangent
        - Horizontal
        - Vertical
- Distribution Conductor Size
- Distribution Phasing
- Distribution Transformer location, size, phase & loading
- Distribution Regulator location, size & phase
- Distribution Capacitors location, size, fixed or switched
- Automatic Circuit Reclosers location, type, phase, & ground pickups
- Fusing location, size & type

Once complete, the model will facilitate the completion of Feasibility, System Impact, and Facilities studies.

Question 1 (Continued)

- A Feasibility studies purpose is to evaluate any adverse system impacts based on the size and type of generation being connected to the distribution system.
- A System Impact studies purpose is to evaluate adverse conditions to the interconnected facilities without any system upgrades or modifications and will determine the impact of the interconnection on the reliability of the electric system.
- A Facilities studies purpose is to provide a cost estimate for the interconnection facilities and system upgrades required to safely interconnect the generator.

Prepared by or under the supervision of: Tracy A. Hazenstab

COMMONWEALTH OF PENNSYLVANIA

OCA Statement 1
10/1/24 G.J.

PATRICK M. CICERO
Consumer Advocate

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
Harrisburg, Pennsylvania 17101-1923
(717) 783-5048
(800) 684-6560

@pa_oca
/pennoca
FAX (717) 783-7152
consumer@paoca.org
www.oca.pa.gov

August 2, 2024

Via Electronic Mail
The Honorable Dennis J. Buckley
The Honorable Alphonso Arnold III
Office of Administrative Law Judge
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division For Approval of its Default Service Program for the Period from June 1, 2025 through May 31, 2029
Docket No. P-2024-3049343

Dear Secretary Chiavetta:

Attached for electronic filing please find a copy of the Direct Testimony being submitted on behalf of the Office of Consumer Advocate in the above-referenced proceeding, as follows:

OCA Statement 1: Direct Testimony of Dr. Serhan Ogur

Copies have been served on the parties as indicated on the enclosed Certificate of Service.

Respectfully submitted,

/s/ Harrison W. Breitman
Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
HBreitman@paoca.org

Enclosures
cc: PUC Secretary Rosemary Chiavetta (Letter and Certificate of Service Only)
Certificate of Service

CERTIFICATE OF SERVICE

Petition of UGI Utilities, Inc. – Electric Division For Approval of its Default Service Program for the Period from June 1, 2025 through May 31, 2029	: : : :	Docket No. P-2024-3049343

I hereby certify that I have this day served a true copy of the following document, the Office of Consumer Advocate's Direct Testimony as follows:

OCA Statement 1: Direct Testimony of Dr. Serhan Ogur

upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below. This document was filed electronically on the Commission's electronic filing system.

Dated this 2nd day of August 2024.

SERVICE BY E-MAIL ONLY

Lindsay Berkstresser, Esquire
UGI Utilities Inc.
500 North Gulph Rd
King of Prussia PA 19406
berkstresserl@ugicorp.com
Counsel for UGI Utilities Inc.

Steve Gray, Esquire
Forum Place
555 Walnut Street, 1st Floor Harrisburg,
Pennsylvania 17101
sgray@pa.gov
OSBA

Anthony D. Kanagy, Esquire
Nicholas A. Stobbe, Esquire
17 North Second St
Harrisburg PA 17101
aganagy@postschell.com
Counsel for UGI Utilities Inc.

Devin T. Ryan, Esquire
Post and Schell PC
One Oxford Centre
301 Grant St suite 3010
Pittsburgh PA 15219
dryan@postschell.com
Counsel for UGI Utilities Inc.

Todd Stewart, Esquire
Hawke, McKeon & Sniscak
LLP 100 N. 10th Street
Harrisburg, PA 17101
tsstewart@hmslegal.com
Counsel for Penn Renewables

/s/*Harrison W. Breitman*
Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
HBreitman@paoca.org

Counsel for:
Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923

Date: August 2, 2024

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF UGI UTILITIES, INC. – ELECTRIC DIVISION FOR APPROVAL OF A DEFAULT SERVICE PLAN (DSP V) FOR THE PERIOD OF JUNE 1, 2025 THROUGH MAY 31, 2029	**)**	**DOCKET NO. P-2024-3049343**

DIRECT TESTIMONY

OF

SERHAN OGUR

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

August 2, 2024

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. SUMMARY OF THE COMPANY's PROPOSED DSP V 5

III. ISSUES AND RECOMMENDATIONS 10

A. Proposed Wholesale Supply Product Portfolio and Related Issues 11

B. Procurement Study 23

OCA Exhibit SO-1 – UGI Electric's Response to OCA Interrogatories Set I-1

OCA Exhibit SO-2 – UGI Electric's Response to OCA Interrogatories Set I-12

APPENDIX A – Summary of Qualifications for Serhan Ogur, Ph.D.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Serhan Ogur. I am a Principal and Senior Economist at Exeter Associates, Inc. ("Exeter"). My office is located at 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. Exeter is a consulting firm specializing in issues pertaining to public utilities.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I received a B.A. degree in Economics from Bogazici University (Istanbul, Turkey) in 1996 and a Ph.D. in Economics from Northwestern University (Evanston, IL) in 2007.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have 23 years of experience in the energy industry specializing in organized wholesale and retail electricity markets. My diverse background comprises energy management and consulting; analysis, design, and reporting of Regional Transmission Organization electricity markets and products; and state and federal regulation of electric utilities. I was employed as Economic Analyst at the Illinois Commerce Commission between 2001 and 2005; Senior Economist at PJM Interconnection, LLC ("PJM") between 2005 and 2014; and Senior System Operator at Fellon-McCord & Associates, LLC between 2014 and 2015. I joined Exeter as Senior Analyst in 2015 and became a Principal of the firm in 2020. A complete description of my professional background is provided in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("COMMISSION")?

A. Yes. I testified in Docket No. P-2016-2534980 in PECO Energy Company's Default Service Program IV proceeding; Docket Nos. P-2020-3019383 and P-2020-3019384 in the joint Default Service Plan VI of Citizens' Electric Company of Lewisburg,

Pennsylvania and Wellsboro Electric Company; Docket No. P-2020-3019522 in Duquesne Light Company's Default Service Plan IX proceeding; Docket No. P-2020-3019907 in UGI Utilities, Inc. – Electric Division's Default Service Plan IV proceeding; Docket No. P-2020-3022988 in Pike County Light & Power Company's Default Service Plan; Docket Nos. A-2021-3025659 and A-2021-3025662 in the case concerning the acquisition of Pike County Light & Power Company and Leatherstocking Gas Company, LLC; Docket Nos. P-2021-3030012, P-2021-3030013, P-2021-3030014 and P-2021-3030021 in the joint Default Service Plan of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company; Docket No. A-2023-3038771 et al in the merger of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company; Docket No. P-2023-3039927 in Pike County Light & Power Company's Default Service Plan; Docket No. P-2024-3046008 in PECO Energy Company's Default Service Program VI proceeding; Docket No. P-2024-3047290 in PPL Electric Utilities Corporation's Default Service Plan VI proceeding; and in Docket No. P-2020-3048592 in Duquesne Light Company's Default Service Plan IX proceeding. All of my prior testimony before the Commission was on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

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 the issues related to residential customers only. However, my recommendations incidentally also impact small commercial customers, that is, commercial customers with annual peak loads less than 100 kilowatts ("kW") since residential and small commercial customers are part of the same default generation service rate class ("GSR-1").

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

A. My testimony addresses certain elements of the proposed Default Service Plan V ("DSP V" or "Plan") of UGI Utilities, Inc. – Electric Division ("UGI" or "UGI Electric" or "Company") for providing default service to its residential and small commercial customers for the 48-month period from June 1, 2025 through May 31, 2029. The specific issues I address include the wholesale power supply products to be procured to satisfy residential and small commercial default service requirements, GSR-1 load cap, and the structure of the Company's proposed reconciliation adjustment. In addition, I address certain issues related to the "Procurement Study" introduced by UGI that was intended to explore the relative cost of default service supply to residential and non-residential customers.

Q. ARE YOU ADDRESSING ANY IMPLEMENTATION OR POLICY ISSUES ASSOCIATED SPECIFICALLY WITH DEFAULT SERVICE FOR COMMERCIAL OR INDUSTRIAL CUSTOMERS?

A. No, I am not. My testimony relates only to issues affecting the residential and small commercial class. However, some of the recommendations I make to improve the process for residential and small commercial customers may also impact the large commercial and industrial customer class.

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 Plan as it affects the residential class. Section III, the final section of my Direct Testimony, provides a discussion of my recommendations concerning the Company's proposed DSP V, and addresses the proposed wholesale supply product portfolio, GSR-1 load cap, the operation of the reconciliation charge, and certain issues related to the

"Procurement Study" introduced by UGI that was intended to explore the relative cost of default service supply to residential and non-residential customers.

Q. ARE YOU RECOMMENDING AN ALTERNATIVE DEFAULT SERVICE SUPPLY PORTFOLIO FOR THE RESIDENTIAL AND SMALL COMMERCIAL CLASS?

A. Yes, I am. I recommend that the residential and small commercial default service supply portfolio consist of 100 percent 24-month fixed-price, full-requirements ("FPFR"), load-following supply contracts, after a 12-month FPFR contract and an 18-month FPFR contract as "catch-up" procurements to start DSP V.

Q. ARE THERE DESIRABLE FEATURES OF THE RESIDENTIAL DEFAULT SERVICE PORTFOLIO PROPOSED BY UGI?

A. I find two features of UGI's proposed residential and small commercial default service portfolio particularly desirable. First, the overlapping or laddering of the delivery terms of the supply contracts helps manage the market price risk for residential and small commercial default service customers by not subjecting them to price changes on the full portfolio at any one time. Second, the overhanging contracts, which are contracts with delivery periods that extend beyond the end of the DSP period, avoid the "hard stop" problem and the associated market price risk that residential and small commercial default service customers would otherwise face at the conclusion of DSP V.

Q. ARE YOU MAKING ANY ADDITIONAL RECOMMENDATIONS?

A. Yes, my testimony includes recommendations on: (1) setting the GSR-1 FPFR "tranche" cap (or load cap) to 75 percent if my recommended GSR-1 default service supply portfolio is also adopted; (2) clarifying UGI's proposal related to the reconciliation of any over- or under-collection of actual revenues against actual costs

for the residential and small commercial class; and (3) rejecting the Company's proposal, based on the findings of the Procurement Study, to continue conducting joint procurements for residential and non-residential GSR-1 (service with supply peak load impact of below 100 kilowatts) customers but setting an Energy Cost rate for residential default service customers that is nearly 10 percent higher than the corresponding rate for non-residential GSR-1 customers.

II. SUMMARY OF THE COMPANY'S PROPOSED DSP V

Q. HAVE YOU REVIEWED THE COMPANY'S PETITION FOR APPROVAL ("PETITION") IN THIS PROCEEDING?

A. Yes. I have reviewed the Company's Petition of the DSP V. I have also reviewed the Direct Testimony and exhibits submitted by UGI in support of its Petition.

Q. WHAT IS THE TIME PERIOD COVERED BY UGI'S PROPOSED DSP V?

A. UGI has proposed a 48-month plan to cover the period from June 1, 2025 through May 31, 2029.

Q. HOW DOES THE COMPANY PROPOSE TO PROVIDE DEFAULT SERVICE TO RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS DURING THE JUNE 1, 2025 THROUGH MAY 31, 2029 PLAN PERIOD?

A. UGI proposes to use a competitive Request for Proposals ("RFP") process to acquire a series of FPFR contracts and energy blocks to provide generation service for the residential and small commercial default service load. The Company states that it will also be responsible for procuring the load-following services (spot energy, capacity, transmission, ancillary services, congestion, Alternative Energy Credits ("AECs"), etc.) associated with the block energy purchases. The block and FPFR contracts would

be in addition to the small, long-term arrangement between UGI and the Allegheny Electric Cooperative, Inc. ("Allegheny").[1]

Q. PLEASE BRIEFLY DESCRIBE UGI'S PROPOSED PLAN AS IT RELATES TO RESIDENTIAL CUSTOMERS.

A. Residential customers are grouped with small commercial customers under UGI's DSP V. The Company proposes the base of the GSR-1 portfolio to consist of 20-megawatt ("MW") around-the-clock ("ATC") block supply (procured annually in 24-month duration contracts with 12-month overlap between two subsequent contracts) in "steady-state" (i.e., starting on November 1, 2025). The Company estimates that each 10-MW ATC block will represent approximately 12 percent load share for GSR-1 related product procurement.[2] The remaining power supply (after Allegheny supply and ATC blocks) would be provided through competitively procured, laddered, 12-month FPFR contracts, and each FPFR contract would represent one-half of the GSR-1 default service load. The FPFR contracts will be procured through RFPs every six months. The Plan proposes that solicitations be conducted between January and March, and then between July and September, in each of the four years covered by the proposed Plan.[3] The proposed procurement schedule would result in a 10-MW block contract and an FPFR contract covering a portion of the load extending past the end of the proposed Plan period (May 31, 2029).[4] The laddering proposed by UGI results in half of the approximately 76 percent of the portfolio consisting of the 12-month FPFR contracts being replaced every six months. The remaining 24 percent of the power supply will be provided through 24-month ATC blocks (20 MW combined in steady-

[1] Petition, paragraph 36.
[2] UGI Electric Statement No. 2, p. 13, line 20 through p. 14, line 2.
[3] UGI Electric Statement No. 2, p. 40, lines 1-2.
[4] UGI Electric Statement No. 2, p. 13, lines 6-9.

state) and Allegheny supply (which will consist of less than one half of one percent of total annual energy requirements of the GSR-1 class).[5] The delivery point for the energy blocks is not specified in UGI's filing, but if the block delivery point in DSP IV is any indication, it would be the PJM Western Hub. For the block energy purchases, UGI will also be responsible for acquiring any capacity, transmission, ancillary services, congestion, AECs, and all other products and services as required to provide default service.

Q. PLEASE EXPLAIN HOW UGI WOULD MEET ITS RESIDENTIAL AND SMALL COMMERCIAL DEFAULT SERVICE OBLIGATION USING FPFR CONTRACTS AND ENERGY BLOCKS.

A. First, using an RFP procurement process, UGI will procure 24-month ATC energy blocks (totaling 20 MW for each hour after November 1, 2025) between January and March in each year of DSP V. Second, using an RFP procurement process, UGI would solicit wholesale supply bids to supply load "tranches," each under a fixed-price contract. A tranche is a fixed percentage of the total residential and small commercial default service load. UGI proposes to split the residential and small commercial default service load into two equal tranches, each representing 50 percent of the total residential and small commercial class default service load in each hour after such load is offset by Allegheny supply and energy blocks.[6] The FPFR contract suppliers would bid a dollar-per-megawatt-hour ("MWh") price to supply all generation products (with certain exceptions) required to serve their share of load (after the block energy and Allegheny supply offsets) – energy, capacity, ancillary services, and required AECs. The FPFR contract price would be fixed for the 12-month contract period. Over the

[5] UGI Electric Statement No. 2, p. 14, lines 13-17.

[6] For example, if in a given clock hour, the GSR-1 load is 120.25 MW, energy blocks are 20 MW combined, and Allegheny supply is 0.25 MW, then the FPFR suppliers' combined energy obligation would be 100 MW.

course of the one-year FPFR contract period, as proposed by UGI, load responsibility measured on a MW and MWh basis can change substantially from initial expectations due to factors such as customer migration to competitive suppliers, migration back to default service from an Electric Generation Supplier ("EGS"), growth (or decline) in the number of residential and small commercial customers, and weather conditions. Under UGI's proposed approach, wholesale FPFR suppliers are exposed to the volumetric risk of uncertain load responsibility while UGI and its residential and commercial default service customers are insulated from this risk. UGI witness Mr. James M. Rouland states that the Company's GSR-1 procurement strategy includes spot market purchases.[7] However, I believe that this statement from Mr. Rouland is erroneous because the definition of the GSR-1 FPFR product's load obligation (GSR-1 load *less* energy blocks *less* Allegheny supply) does not leave any GSR-1 energy responsibility to balance in PJM spot market for UGI. Since UGI is also responsible for acquiring capacity, transmission, ancillary services, congestion (between the UGI Residual Metered Load Aggregate and the Western Hub), and AECs for energy blocks, the volumetric and price risk for these components is borne by UGI and its residential and small commercial default service customers.

Q. HOW DOES UGI PROPOSE TO TREAT CAPACITY AND NON-MARKET BASED TRANSMISSION SERVICE ("NMB") CHARGES IN FPFR CONTRACTS?

A. UGI proposes to pull back NMB charges (which include PJM's Network Integration Transmission Service, Regional Transmission Enhancement Planning, and Generation Deactivation charges) from FPFR suppliers, and assume responsibility for these

[7] UGI Electric Statement No. 2, p. 19, line 22 through p. 20, line 13.

charges.[8] The Company is also proposing to provide guidance and relief to suppliers if and when the term of the FPFR contract overlaps with a future capacity period for which PJM has not yet issued a final capacity price or for which no capacity price yet exists. UGI will credit or debit suppliers for the difference between the capacity price upon which bids are based and the actual capacity price.[9] The Company is taking these steps to reduce FPFR suppliers' unhedgeable risk, and as a result increase supplier participation in auctions and/or lower risk premiums embedded in the supplier bids.

Q. HOW OFTEN WOULD GSR-1 RATES CHANGE UNDER UGI'S DEFAULT SERVICE PROPOSAL?

A. GSR-1 rates would change semi-annually, on June 1 and December 1 of each year, starting on June 1, 2025.[10] This represents a welcome change, for rate stability-seeking residential customers, from UGI's current Default Service Plan (DSP IV), under which GSR-1 rates were adjusted quarterly.

Q. HOW OFTEN WOULD UGI CHANGE ITS REVENUE RECONCILIATION RATE?

A. The Company's filing contains contradictory information on this issue. On page 12 (lines 24-29) of her Direct testimony, UGI witness Ms. Tracy A. Hazenstab states:

> *If the ECA would result in less than (or equal to) five percent (5%) change in the average total Residential bill, the Company will calculate the ECA over six-months of sales. If the ECA would result in more than a 5% change in the system average total Residential bill for default service, UGI will refund/recover the balance over twelve months of sales.*

However, on page 14 (lines 16-18) of her Direct testimony, Ms. Hazenstab states:

> *[T]he June 1 rate will capture the actual over/under collection for the period October 1 – March 31 and the December 1 rate will calculate the actual over/under collection for the period April 1 – September 30.*

[8] UGI Electric Statement No. 2, p. 18, lines 7-16.

[9] UGI Electric Statement No. 2, p. 17, line 14 through p. 18, line 1.

[10] UGI Electric Statement No. 3, p. 14, lines 7-12.

Ms. Hazenstab's statement on page 12 of her Direct Testimony suggests that over- or under-collections over a six-month period would be amortized over either a subsequent six-month period or a subsequent 12-month period (depending on the residential rate impact of the reconciliation balance) while her statement on page 14 of her Direct Testimony suggests that over- or under-collections over a six-month period would necessarily be amortized over a subsequent six-month period. The Company should clarify its proposal. The language on page 12 of Ms. Hazenstab's Direct Testimony would be more appropriate for residential customers because of the importance of rate stability for residential customers.

However, to avoid the administrative complexity associated with determining the residential rate impact of a reconciliation balance and extending the rate stability benefit of a longer-term amortization to all rate periods, I recommend that the Commission adopt a 12-month amortization period for over- or under-collection balances reconciled over a six-month period.

III. ISSUES AND RECOMMENDATIONS

Q. WHAT ISSUES DO YOU ADDRESS IN THE REMAINDER OF YOUR DIRECT TESTIMONY?

A. In this final section of my testimony, I address: (1) UGI's proposed residential and small commercial default service supply arrangement; (2) GSR-1 load caps; and (3) certain issues related to the "Procurement Study" introduced by UGI that was intended to explore the relative cost of default service supply to residential and non-residential customers.

A. Proposed Wholesale Supply Product Portfolio and Related Issues

Q. PLEASE DESCRIBE THE GSR-1 DEFAULT SERVICE SUPPLY PORTFOLIO IN UGI'S CURRENTLY EFFECTIVE PLAN (DSP IV).

A. UGI's GSR-1 default service supply portfolio in DSP IV consists of 24-month FPFR contracts (25 percent of GSR-1 requirements); 12-month FPFR contracts (50 percent of GSR-1 requirements); shorter-term energy block contracts balanced with PJM spot market purchases and sales (25 percent of GSR-1 requirements); and Allegheny supply (less than one half of one percent of GSR-1 requirements), which is used to offset FPFR suppliers' energy obligations. UGI also procured a six-month FPFR contract as a catch-up purchase at the beginning of DSP IV.[11] It is important to note that the block-and-spot portion of the GSR-1 supply portfolio has its own 25 percent carveout, so the energy blocks do not offset or affect FPFR suppliers' energy obligations. The energy obligations of FPFR suppliers are defined as the load ratio share of each tranche (25 percent) after the Allegheny supply offset.[12]

Q. PLEASE DESCRIBE THE GSR-1 DEFAULT SERVICE SUPPLY PORTFOLIO PROPOSED BY UGI FOR DSP V.

A. UGI proposes to procure approximately 24 percent of the GSR-1 energy supply through laddered 24-month ATC energy blocks (20 MW in total starting on November 1, 2025; 10 MW before November 1, 2025), and self-supply other products and services (capacity, transmission, ancillary services, congestion, AECs) needed to provide full-requirements default service to residential and small commercial customers. The Company proposes to procure the remaining approximately 76 percent of GSR-1 full-requirements (with certain exceptions, such as NMB costs) supplies through competitively procured, laddered, 12-month FPFR contracts. Each 12-month FPFR

[11] UGI Electric Statement No. 2, p. 4, line 18 through p. 6, line 4.
[12] UGI Electric Statement No. 2, p. 5, line 22 through p. 6, line 4.

contract would represent one half of the residential and small commercial default service supply load after such load is offset by energy blocks and Allegheny supply.[13]

Q. WHAT ARE THE REASONS OFFERED BY UGI FOR PROPOSING THESE CHANGES RELATED TO THE GSR-1 DEFAULT SERVICE PORTFOLIO FROM DSP IV TO DSP V?

A. Mr. Rouland states that, in addition to meeting the statutory requirements for provision of default service, UGI has identified two specific areas of focus: (1) maximizing supplier participation by reducing risks to suppliers; and (2) providing greater price stability over time, including the period at the beginning of the subsequent plan period (DSP VI) and lowering administrative burdens.[14] Mr. Rouland also states that the small size of the Company's GSR-1 default service load compared to other Pennsylvania electric distribution companies ("EDCs") also guided the Company's portfolio design.[15] Finally, Mr. Rouland posits that supplier participation in FPFR solicitations decreased, and that UGI believes that the decline in supplier participation was due to the variance in block sizes procured for each month over the course of DSP IV.[16]

Q. DO YOU CONCUR THAT VARIABLE BLOCK SIZING WOULD AFFECT SUPPLIER RISK AND PARTICIPATION IN FPFR SOLICITATIONS IN DSP IV?

A. No. As I explained earlier, the block-and-spot portion of the GSR-1 supply portfolio in DSP IV has its own 25 percent carveout, so the energy blocks do not offset FPFR suppliers' energy obligations. Therefore, load obligation, profile, or risk of an FPFR supplier is independent of the sizing of the Company's block purchases.

[13] Petition, paragraph 46.
[14] UGI Electric Statement No. 2, p. 8, lines 14-23.
[15] UGI Electric Statement No. 2, p. 10, lines 3-10.
[16] UGI Electric Statement No. 2, p. 15, lines 9-12.

Q. DOES THE COMPANY PROVIDE A REASON FOR ELIMINATING THE 24-MONTH FPFR CONTRACT FROM THE GSR-1 SUPPLY PORTFOLIO FOR DSP V?

A. No. None of the observations made by UGI related to its procurements during DSP IV apply exclusively to the 24-month FPFR contracts. The Company appears to have experienced reduced supplier participation during and since the period of wholesale natural gas and power market volatility in 2021 and in 2022 for all FPFR products, including 12-month and 24-month FPFR contracts. Mr. Rouland also notes that pricing for the FPFR contracts continued to be within the range of market expectations despite lower participation.[17]

Q. HAVE YOU REVIEWED THE RESIDENTIAL DEFAULT SERVICE SUPPLY PRODUCT PORTFOLIOS EMPLOYED AND/OR PROPOSED BY OTHER PENNSYLVANIA EDCs?

A. Yes, I have. Duquesne Light Company's (Duquesne's) residential portfolio consists 50 percent of 12-month FPFR contracts and 50 percent 24-month FPFR contracts. The residential default service portfolio of each respective FirstEnergy EDC (Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company) relies 50 percent on 12-month FPFR contracts and 50 percent on 24-month FPFR contracts. PECO Energy Company's ("PECO's") residential portfolio comprises 38 percent 12-month FPFR contracts, 61 percent 24-month FPFR contracts, and 1 percent spot market purchases. PPL Electric's current residential portfolio features a five-year, 100-MW, around-the-clock energy block and the remaining default service load is provided through 20 percent 6-month FPFR contracts and 80 percent 12-month FPFR contracts. In its plan for the next default

[17] UGI Electric Statement No. 2, p. 8, lines 1-11.

service plan period, citing excessive volatility in its residential default service rate, PPL Electric proposed to increase the size of the energy block to 150 MW and the term of the block to 10 years (which would correspond approximately to 15 percent of the residential default service energy consumption), and rely on 24-month (for 80 percent of the requirements after the application of the 150 MW block) and 12-month (for 20 percent of the requirements after the application of the 150 MW block) FPFR contracts. Citizens' and Wellsboro currently rely 100 percent on a 48-month FPFR contract with indexed, laddered, energy pricing.

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF THE PERFORMANCE OF UGI'S CURRENT AND PROPOSED RESIDENTIAL AND SMALL COMMERCIAL DEFAULT SERVICE SUPPLY PORTFOLIO FROM A RATE STABILITY PERSPECTIVE.

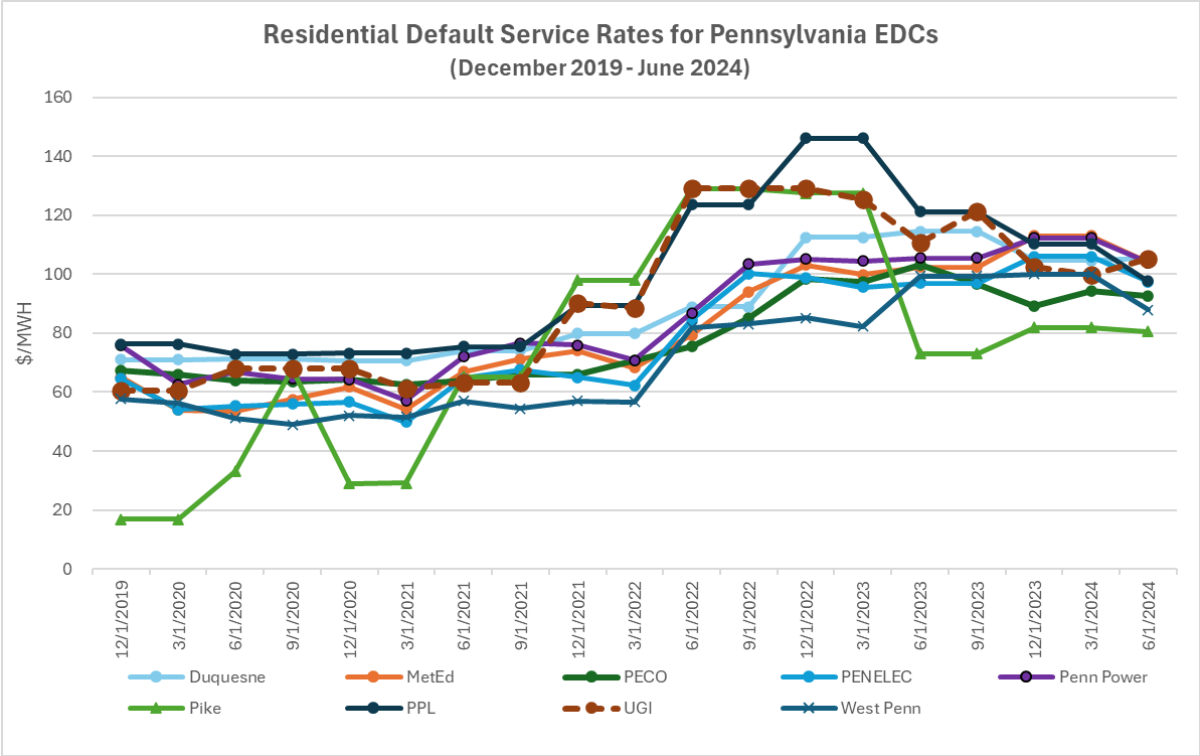
A. Table 1 and Figure 1 below show that UGI's residential default service portfolio resulted in larger default service rate (price-to-compare, or "PTC") volatility relative to other EDCs in Pennsylvania during the recent wholesale power and natural gas market volatility. Table 1 presents the relative standard deviation (the ratio of standard deviation to average) of Pennsylvania EDCs' quarterly PTC, sorted in ascending order, from December 2019 to June 2024. Figure 1 is a visual representation of the trend of PTCs of Pennsylvania EDCs. PECO had the lowest PTC volatility among Pennsylvania EDCs over the last four years, followed closely by DLC. Both PECO and Duquesne have been procuring residential default service supplies in the form of 24-month and 12-month FPFR contracts, with approximately equal share of each. I infer from Table 1 that the residential default service supply portfolio composition employed by PECO and Duquesne delivered the smallest default service rate volatility among Pennsylvania EDCs during a 4.5-year period which comprised of sub-periods of both stable and

volatile wholesale market conditions. The EDCs using shorter-term FPFR contracts and/or relying substantially on spot market pricing generated more volatile PTCs for their residential default service customers. UGI's proposal to eliminate the shorter-term blocks and spot market exposure (and replacing it with 24-month blocks) would increase the stability of the GSR-1 PTC, but elimination of the 24-month FPFR component (and replacing it with 12-month FPFR contracts) would increase rate volatility. The net effect of these two countervailing forces may not increase UGI's GSR-1 PTC stability much, if at all. I believe UGI can deliver better rate stability than this for its residential and small commercial default service customers.

Table 1

Volatility of Residential Default Service Rates of Pennsylvania EDCs			
EDC	**Standard Deviation**	**Average**	**Relative Standard Deviation**
PECO	$15.01/MWh	$78.26/MWh	19%
Duquesne	17.83	88.40	20%
Penn Power	19.54	85.58	23%
PPL	25.74	98.67	26%
PENELEC	20.64	77.82	27%
Met-Ed	21.60	80.94	27%
West Penn	19.77	71.67	28%
UGI	26.99	91.78	29%
Pike	37.66	74.87	50%

Figure 1



Q. ARE YOU RECOMMENDING ANY CHANGES TO THE WHOLESALE SUPPLY PRODUCT PORTFOLIO PROPOSED BY UGI?

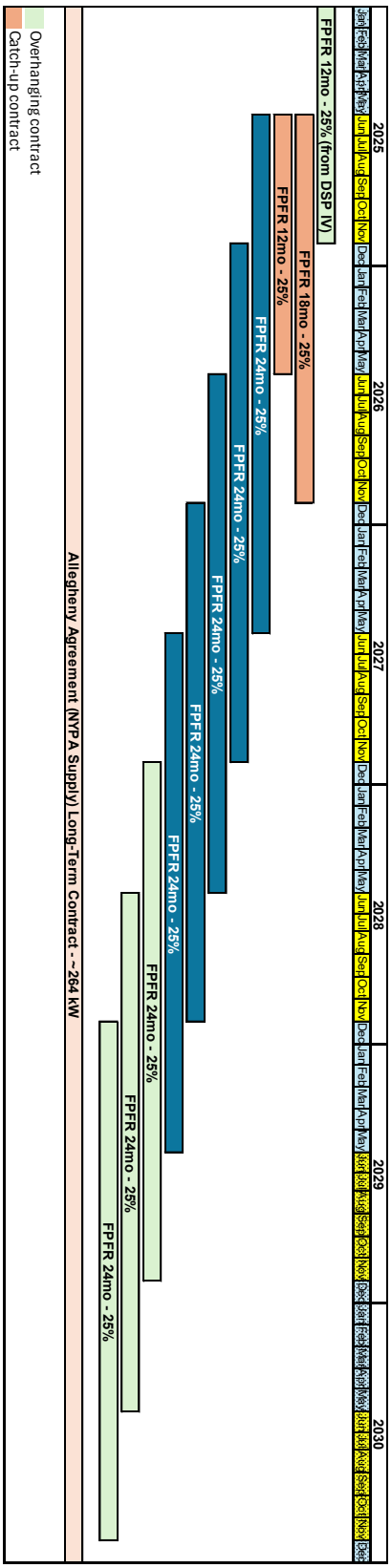
A. Yes, I am. I recommend that the residential and small commercial default service supply portfolio consist of 100 percent 24-month FPFR contracts, after a 12-month FPFR contract and an 18-month FPFR contract as "catch-up" procurements to start DSP V.

Q. HAVE YOU CREATED A PROCUREMENT SCHEDULE DETAILING THE SUPPLY PRODUCTS YOU ARE RECOMMENDING AND OPERATIONALIZING THE PROCUREMENT OF THE PORTFOLIO?

A. Yes, I have. The procurement schedule I am recommending is presented in Figure 2. I split the residential and small commercial default service load into four equal tranches, each tranche representing 25 percent of the load in each hour. All four tranches are to

be served through 24-month FPFR contracts. I am also recommending that the Company procure a 24-month FPFR contract every six months, which implies that the delivery periods of any two 24-month FPFR contracts procured subsequently to each other would overlap by six months. I am not proposing any changes to the procurement dates proposed by UGI. Thus, under my proposal, the Company would procure a 24-month FPFR contract with a delivery period starting on June 1 between January and March of the same calendar year; and a 24-month FPFR contract with a delivery period starting on December 1 between July and September of the same calendar year.

Figure 2


2025
2026
2027
2028
2029
2030
FPFR 12mo - 25% (from DSP IV)
FPFR 18mo - 25%
FPFR 12mo - 25%
FPFR 24mo - 25%
FPFR 24mo - 25%
FPFR 24mo - 25%
FPFR 24mo - 25%
FPFR 24mo - 25%
FPFR 24mo - 25%
Allegheny Agreement (NYPA Supply) Long-Term Contract - ~264 kW
Overhanging contract
Catch-up contract

Q. WHY ARE YOU RECOMMENDING THAT 24-MONTH ATC BLOCK PURCHASES PROPOSED BY UGI BE REPLACED WITH 24-MONTH FPFR CONTRACTS?

A. While I concur with Mr. Rouland that some Pennsylvania EDCs include ATC energy blocks in their residential default service supply portfolios, those blocks are typically longer-term blocks than the ones proposed by UGI. For example, PPL has procured five-year blocks during its current DSP and proposed a 10-year block for its subsequent DSP. If the term of the ATC block is limited to two years, it would be preferable to procure 24-month FPFR contracts instead because of their full-requirements nature. I also note that, since UGI proposes to use the ATC blocks to offset FPFR suppliers' energy requirements, a 24-month FPFR contract without any ATC block offsets would in effect roll the ATC block into the FPFR contract while avoiding the Company's need to self-provide non-energy attributes (e.g., capacity, ancillary services, congestion, AECs) of a full-requirements contract. However, if UGI were to propose a five-year or 10-year energy block similar to PPL, I would not necessarily be opposed to that proposal or to offsetting FPFR suppliers' energy obligations by the energy block deliveries since it is not feasible to procure a five-year or a 10-year FPFR contract, at least without paying an excessive risk premium.

Q. ARE THE 24-MONTH FPFR PRODUCTS WHICH YOU ARE RECOMMENDING FOR THE GSR-1 DEFAULT SERVICE PORTFOLIO TOO RISKY FOR WHOLESALE SUPPLIERS TO BID ON?

A. No. First, most Pennsylvania EDCs have been procuring them for their respective residential and small commercial default service portfolios successfully. Second, Mr. Rouland states that UGI successfully procured 24-month FPFR contracts during DSP IV, and the pricing for such FPFR contracts continued to be within the range of market

expectations.[18] Finally, as Mr. Rouland explains, the Company is proposing to make material changes to the FPFR products which would reduce FPFR suppliers' risk, including removing NMB costs from the wholesale suppliers' obligations and providing guidance and after-the-fact reconciliation on capacity pricing when PJM has not determined the final zonal capacity rate. These changes would make 24-month FPFR contracts less risky for wholesale suppliers in DSP V than they were in DSP IV.

Q. HOW DOES THE TRANCHE SIZE IN MWH OF ENERGY IN A 24-MONTH FPFR CONTRACT AS PROPOSED BY YOU COMPARE TO A 12-MONTH FPFR CONTRACT AS PROPOSED BY UGI?

A. I am proposing to divide the GSR-1 default service load into four equal tranches and procure a 24-month FPFR contract for each such tranche without offsetting the load by energy blocks. UGI has proposed to divide the GSR-1 default service load into two equal tranches and procure a 12-month FPFR contract for each such tranche after offsetting the load by energy blocks. The FPFR contract I am recommending would have the same MWh as the one proposed by the Company because the contract I am proposing has half the share of the load but twice the duration of the one proposed by UGI. Since the energy requirements of the wholesale supplier in the FPFR contract proposed by UGI would be reduced by the amount of block energy deliveries (approximately 24 percent of the total GSR-1 class default service energy requirements in steady-state) but not in the FPFR contract which I am proposing, the FPFR contract I am proposing would include approximately 30 percent more MWh than the one being proposed by the Company. Therefore, if tranche size or a wholesale suppliers' energy requirement size being too small is of concern, the 24-month FPFR contract I am proposing would be more attractive to wholesale suppliers.

[18] UGI Electric Statement No. 2, p. 8, lines 1-11.

Q. ARE YOU RECOMMENDING A DIFFERENT GSR-1 LOAD CAP THAN WHAT IS PPROPOSED BY THE COMPANY?

A. If my proposed GSR-1 default service supply portfolio is adopted, yes. The Company has proposed a 50 percent load cap (or tranche cap) for GSR-1 FPFR procurements.[19] Since the Company has proposed to divide the GSR-1 default service load into two equal tranches, the effective load cap could either be 50 percent or 100 percent. On the other hand, since I am proposing to divide the GSR-1 default service load into four equal tranches, in addition to 50 percent and 100 percent, 75 percent (i.e., a supplier would be limited to serving at most three GSR-1 tranches out of a total of four tranches at any given point in time) is also a possibility for a load cap under my proposed supply portfolio. If 50 percent is selected as the load cap under my proposed supply portfolio, then a supplier that is awarded the tranche in two subsequent solicitations could not participate in the two solicitations following those first two solicitations. Setting the load cap at 75 percent would restrict a supplier to sit out at most one solicitation in four semi-annual solicitations. Since UGI is concerned about, and wants to maximize, supplier participation, a 75 percent load cap would strike a better balance between maximizing competition in the solicitations and reducing counterparty risk by limiting exposure to a single wholesale supplier.

Q. WHY IS YOUR RECOMMENDED PORTFOLIO PREFERABLE TO UGI'S PROPOSED PORTFOLIO FOR RESIDENTIAL AND SMALL COMMERCIAL DEFAULT SERVIVE CUSTOMERS?

A. I find my recommended portfolio preferable to the portfolio proposed by the Company for the residential and small commercial default service customers for four reasons. First, my recommended portfolio offers better rate stability due to the product

[19] UGI Electric Statement No. 2, p. 12, lines 18-21.

durations. While approximately 44 percent of the Company's proposed portfolio would turn over every six months on average, only 25 percent of my proposed portfolio would turn over every six months. Second, my recommended portfolio reduces the administrative and operational burden on the Company. When block energy purchases are eliminated from the residential and small commercial default service supply portfolio, it also obviates the need for UGI to perform load forecasts for block size determination purposes; acquire AECs required to serve the load associated with the energy blocks; and settle capacity, congestion, and ancillary services costs in PJM. Third, my recommended portfolio reduces the number of products to be procured by UGI and increases the number of MWh in each tranche. An FPFR contract with a larger sales volume would be more appealing to wholesale suppliers than an FPFR contract with a smaller sales volume. Finally, my proposed portfolio extends the benefits of rate stability deeper into the subsequent DSP period compared to UGI's proposed portfolio.

Q. DO YOU AGREE WITH UGI'S PROPOSAL TO PROCURE OVERHANGING CONTRACTS?

A. Overhanging contracts are used to avoid the problem of a hard stop, which occurs when 100 percent of a new portfolio must be procured at the beginning of the subsequent default service plan period because all of the power purchase agreements expire at the conclusion of the prior plan period. UGI proposes procuring a 12-month FPFR contract that extends into the first six months of the subsequent DSP period and a 10-MW ATC block which extends into the first 12 months of the subsequent DSP period. I agree with the Company's proposal to procure contracts with a delivery period extending into the subsequent DSP period. In fact, my recommended procurement schedule which is presented in Figure 2 proposes to acquire three FPFR contracts (75 percent of the GSR-1 supply requirements) into the first six-month subperiod of the subsequent DSP

period; two FPFR contracts (50 percent of the GSR-1 supply requirements) into the second six-month subperiod of the subsequent DSP period; and one FPFR contract (25 percent of the GSR-1 supply requirements) into the third six-month subperiod of the subsequent DSP period. The use of overhanging FPFR contracts extends the price stability benefits of my recommended DSP IV portfolio into the beginning part of the Company's subsequent DSP period.

Q. IS UGI'S PROPOSED PROCUREMENT METHOD FOR RESIDENTIAL AND SMALL COMMERCIAL DEFAULT SERVICE CUSTOMERS ACCEPTABLE?

A. Yes, it is. UGI is proposing to employ a sealed-bid RFP approach to procure FPFR contracts and energy blocks for residential and small commercial default service loads where each accepted offer is paid its bid price. It is one of the standard procurement methods in the electricity industry. Furthermore, UGI has relied on an RFP approach in the past and, to my knowledge, has not encountered any adverse consequences that would suggest that an alternative approach should be considered.

B. Procurement Study

Q. WHY DID UGI COMMISSION THE "PROCUREMENT STUDY?".

A. As one of the conditions of UGI's DSP IV settlement, UGI agreed to file a study:

> *Before June 30, 2022, the Company will file a study of the relative cost of default service supplies for GSR-1 residential and non-residential customers. The Company may select a consultant of its choosing to perform the study. The filing will include all workpapers and assumptions used in the analysis, subject to reasonable confidentiality restrictions as necessary. The study will rely on data from DSP III, DSP IV and actual data through at least the Fall of 2021. The study will evaluate the relative costs to GSR-1 residential and non-residential customers associated with: (1) both block-and-spot and full requirements procurements methods; and (2) both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement.*[20]

[20] UGI Electric Exhibit JRT-2, Appendix A ("Procurement Study"), p.1.

The Company commissioned the study (hereafter, the "Procurement Study") to the Northbridge Group and the resulting report is provided in UGI's DSP V filing.

Q. WHAT DID THE AUTHORS OF THE PROCUREMENT STUDY CONCLUDE?

A. The authors of the Procurement Study concluded that (1) residential GSR-1 customers would be between 8 percent and 9 percent more costly (on a $/MWh of load basis) to serve than non-residential GSR-1 customers;[21] and (2) conducting separate procurements for the residential and non-residential GSR-1 customer classes would increase UGI's annual administrative costs by $24,200.[22]

Q. WHAT DID THE AUTHORS OF THE PROCUREMENT STUDY RECOMMEND BASED ON THEIR CONCLUSIONS?

A. The authors of the Procurement Study did not make explicit recommendations. They stated that "maintaining UGI's combined GSR-1 group may be the more prudent approach," and they outlined a cost allocation approach which the Commission could consider. That cost allocation approach is determining the Energy Cost ("EC") rate (in $/MWh), which is the projected direct and indirect purchased power costs incurred by UGI to acquire electric supply for the GSR-1 group, and then setting residential and non-residential GSR-1 EC rates two percent higher and seven percent lower, respectively, than this combined EC rate.

Q. WHAT DID UGI PROPOSE IN THE DSP V FILING?

A. UGI proposed to conduct combined procurements for the entire GSR-1 group and apply the residential and non-residential allocation factors of 1.02 and 0.93, respectively, to

[21] Procurement Study, p. 2.
[22] Procurement Study, p. 17.

the EC rate component in determining separate EC rates for residential and non-residential GSR-1 default service customers.

Q. CAN THE FINDINGS AND CONCLUSIONS OF THE PROCUREMENT STUDY BE RELIED UPON TO SET AN EC RATE FOR RESIDENTIAL CUSTOMERS THAT IS 10 PERCENT HIGHER THAN THE EC RATE FOR NON-RESIDENTIAL GSR-1 CUSTOMERS?

A. No. The methodology and assumptions of the Procurement Study are flawed in a way that accounts for the factors which would result in lower cost for non-residential GSR-1 customers but neglects to account for the factors which would result in lower cost for residential customers. Consequently, the Procurement Study biases the hypothetical cost of serving residential customers relative to the hypothetical cost of serving non-residential GSR-1 customers higher, Therefore, the residential and non-residential GSR-1 relative cost factors of 1.02 and 0.93, respectively, as reported in the Procurement Study, cannot be relied upon to arbitrarily increase (lower) the EC rate to residential (non-residential GSR-1) customers.

Q. WHAT ARE THE FACTORS, OR COST COMPONENTS, WHICH WOULD RESULT IN LOWER COST FOR NON-RESIDENTIAL GSR-1 CUSTOMERS?

A. Capacity and transmission (comprised mostly of the Network Integration Transmission Service, or NITS, PJM billing line item) charges are incurred based on respective measures of peak load (measured in MW). Residential customers typically have slightly lower load factors (ratio of average load to peak load) than small non-residential customers. As a result, on a $/MWh of load basis, residential customers have slightly higher capacity and transmission costs than small non-residential customers. Residential and small non-residential customers also have different load profiles (usage

patterns by time of day or season). Hourly wholesale electricity prices in PJM's spot markets vary substantially from hour to hour based on a number of factors. To the extent that residential customers increase their electricity usage during these high system load and high spot price hours more so than small non-residential customers do, energy costs on average for residential customers may also be higher than for small non-residential customers.

Q. DID THE PROCUREMENT STUDY DIRECTLY AND EXPLICITLY ACCOUNT FOR THESE COST ELEMENTS?

A. Yes. The Procurement Study directly estimated the cost of capacity, transmission, and energy separately for each GSR-1 customer group.

Q. WHAT ARE THE FACTORS WHICH WOULD RESULT IN LOWER COST FOR RESIDENTIAL GSR-1 CUSTOMERS?

A. The most important, but not the only, such factor under the FPFR procurement approach is volumetric risk. As I explained in this Direct Testimony, load responsibility measured on a MW and MWh basis can change substantially from initial expectations due to factors such as customer migration to competitive suppliers, migration back to default service from an EGS, growth (or decline) in the number of residential and small commercial customers, and weather conditions. Under UGI's proposed approach, wholesale FPFR suppliers are exposed to the volumetric risk of uncertain load responsibility while UGI and its residential and commercial default service customers are insulated from this risk. In return for assuming this risk of uncertain load responsibility, FPFR suppliers include a risk premium in their FPFR contract bids (in $/MWh). The larger the migration (or switching or shopping) risk is, the larger the corresponding risk premium would be.

Q. DID THE PROCUREMENT STUDY DIRECTLY AND EXPLICITLY ACCOUNT FOR THE COST OF THIS SWITCHING RISK?

A. No. The authors attempt to estimate it for each respective GSR-1 customer class indirectly, but their methodology is flawed and therefore their estimates are unreliable. They estimate a category they refer to as "other costs," defined as the difference between the FPFR auction price (in $/MWh) and the authors' estimation of energy, capacity, and transmission costs (in $/MWh) for PECO's FPFR auctions conducted separately for residential and small commercial customers between 2017 and 2022. They compute an "other costs" average separately for PECO's residential and small commercial default service FPFR auctions, and then use this ratio to estimate the projected ratio of the residential class "other costs" to the small non-residential class "other costs."

Q. WHY IS THIS METHODOLOGY FLAWED AND UNRELIABLE FOR ESTIMATING FORWARD-LOOKING SWITCHING RISK-DRIVEN FPFR CONRACT RISK PREMIUMS FOR EACH CUSTOMER CLASS?

A. This methodology is flawed and therefore its results are unreliable for two reasons. First, "other costs" is a very broad category which includes costs of ancillary services, customer credits associated with congestion rents (Auction Revenue Rights, or ARRs), a long list of other PJM services that are billed directly by PJM, and AECs. As the Procurement Study explains, "other costs" also include costs that result from the risks associated with default service supply. Such risks are often associated with customer migration and its effect on the default service volumes to be supplied usage and wholesale market price uncertainty, potential changes in laws and regulations that could impact costs, and credit-related costs.[23] The authors of the Procurement Study

[23] Procurement Study, p. 4.

could easily have directly estimated most of these elements (e.g., ARRs, AECs, PJM ancillary services and other line items billed directly by PJM) which were instead thrown into the "other costs" bucket. It is even more problematic to estimate relative levels of "other costs" for one EDC's (in this instance, PECO's) residential and small commercial FPFR contracts, and assume the same ratio for another EDC's (i.e., UGI's) residential and small commercial FPFR contracts.

Second, and more importantly, the Procurement Study ignored the shopping and switching characteristics of each customer class in PECO and in UGI, and the variation of inter-class differences between the two utilities.[24] Ignoring switching characteristics amounts to neglecting a major component of the risk premium. As I show below, the difference in shopping and switching propensity between PECO's residential and small commercial customers is vastly different than the difference in shopping and switching propensity between UGI's residential and small commercial customers, which renders the Procurement Study's foundational assumption invalid.

Q. DOES THE PROCUREMENT STUDY ESTIMATE RELATIVE COSTS BASED ON AN FPFR APPROACH OR A BLOCK-AND-SPOT APPROACH?

A. The authors claim that the analysis they conduct applies to both approaches, and that the results would be identical, because "the supply itself consists of the same basic components."[25]

Q. DO YOU CONCUR WITH THIS CLAIM?

A. No. This is a major flaw in the Procurement Study. As the Study's authors also acknowledge, the FPFR approach entails the incurrence of risk by the wholesale

[24] UGI's Response to OCA Set I, #1c.
[25] Procurement Study, p. 3.

supplier and the incurrence of the associated risk premium by the customers, whereas the block-and-spot approach does not entail the incurrence of a risk premium by the customers.[26] Under block-and-spot, customers incur direct costs and bear the increased cost and rate volatility associated with exposure to certain risks, but they do not pay a (implicit or explicit) risk premium to a wholesale supplier or to the EDC. Therefore, the same analysis cannot be conducted for both approaches and the results of the same analysis cannot be equally applicable for both approaches. The approach taken in the Procurement Study may be better suited for the block-and-spot approach, but it is ill-suited for the FPFR approach because it ignores the risk associated with customer switching and shopping. Since UGI is not proposing any block-and-spot component in its DSP V GSR-1 default service supply portfolio, the Procurement Study's relative cost factor estimates cannot be relied upon to set a higher EC rate for residential customers than for GSR-1 non-residential customers.

Q. WHY ARE CUSTOMER SHOPPING CHARACTERISTICS AND SWITCHING RISK IMPORTANT?

A. In his response to OCA Set I, #12, Mr. Rouland explained the importance of switching risk as follows:

> *The GSR-2 rate group includes those commercial and industrial customers that are above a 100 kW demand split. As discussed in UGI Electric Statement No. 2, the Direct Testimony of James M. Rouland, page 22, lines 8-18, this customer group includes those customers that are often more sophisticated and often shop for their electricity. Given the mobility larger commercial and industrial customers - entering and leaving default service - wholesale supplier bids for fixed product offerings, such as that which is offered for GSR-1 customers, is likely to yield a high risk premium, if obtaining a bid at all, given the load variability inherent with this customer segment. These premium increases would be a result of wholesale suppliers attempting to protect themselves from the load variability with energy products they secure as a component of their product mix - some of which may be for block products or other structured, firm supply obligations which are at risk if the load obligation drops below the expected supply amount.*

[26] Procurement Study, p. 4.

The statement made in UGI Electric Statement No. 2, the Direct Testimony of James M. Rouland, page 22, lines 20-22 and page 23, lines 1-2, were in reference to the Commission's Retail Market Investigation position with regard to implementation of a commercial and industrial customer demand split. Specifically, that without the demand split there was a risk that those customers that are both large in their relative consumption level and active in the retail market would increase the cost of fixed price default service rate offerings through wholesale supplier risk premiums, thereby causing smaller and less active retail market participant to pay for large customer's movements. Said another way, that larger commercial and industrial customers benefit from a fixed price offering at the cost of smaller less active commercial and industrial customers. In UGI Electric's case, the impact is greater as the GSR-1 rate group includes residential customers in additional to commercial and industrial customers at or below 100 kW.

While Mr. Rouland's explanation is in regards to the importance of the difference in the shopping characteristics and switching risk between GSR-1 and GSR-2 (large commercial and industrial) customer groups, the same logic and conclusion would be just as true and relevant for the difference in the shopping characteristics and switching risk between residential and non-residential GSR-1 customers because of vastly different shopping and switching profiles of residential and non-residential GSR-1 customers.

Q. PLEASE DEMONSTRATE THE DIFFERENCE BETWEEN SHOPPING AND SWITCHING PROFILES OF RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS IN PECO AND IN UGI.

A. Table 2 shows the percentage of total generation sales to residential and small commercial retail customers of UGI and PECO made by EGSs from 2015 through 2022 on an annual basis. Table 2 also depicts the eight-year standard deviation, average, and relative standard deviation (ratio of standard deviation to average) for each customer class for each utility. I note three observations from Table 2. First and foremost, UGI's residential customer shopping percentage is negligible, and it has consistently been negligible for the last eight years. Therefore, from an FPFR supplier's perspective, UGI's residential default service customers would have negligible switching risk.

Second, UGI's non-residential GSR-1 customers have much higher shopping rates (fluctuating between 21 percent and 36 percent on an annual basis from 2015 through 2022, averaging 27 percent in terms of MWh volume) than UGI's residential customers. More importantly, the variability of the EGS shopping rate of UGI's non-residential GSR-1 customers is also high (as measured by relative standard deviation of 23 percent). In comparison, the relative standard deviation of EGS shopping rate of PECO's small commercial customers is 7 percent, or less than one-third of that of UGI's small commercial customers. Among the four groups reviewed in the Procurement Study (UGI residential, UGI small commercial, PECO residential, and PECO small commercial customers), UGI small commercial customers by far have the highest shopping rate volatility as measured by relative standard deviation. The obvious conclusion from these comparisons is that UGI's non-residential GSR-1 customers constitute a much larger switching risk than UGI's residential customers for an FPFR supplier.

Finally, Table 2 invalidates the methodology of and the assumptions inherent in the Procurement Study in relation to the estimation of "other costs" differential or ratio between UGI's residential and non-residential GSR-1 customers. The Procurement Study estimated a ratio of "other costs" for PECO's residential default service customers to "other costs" for PECO's small commercial customers, and assumed the same ratio would be applicable to UGI's residential and non-residential GSR-1 customers. As Table 2 and my observations above demonstrate, the switching risk (15 percent, as measured by relative standard deviation of annual shopping rates) of PECO's residential customers is twice as high as the switching risk of PECO's small commercial customers, whereas the switching risk of UGI's small commercial customers is many times larger than the switching risk of UGI's residential

customers. Since the Procurement Study ignored this switching risk and its effect on FPFR contract risk premiums for each respective customer class, the Procurement Study underestimated the risk premium for UGI's non-residential GSR-1 customers overestimated it for UGI's residential customers.

Table 2

Shopping & Switching Trends of Residential and Small Commercial Customers, UGI and PECO				
	UGI		PECO	
	EGS Share of Total Residential Megawatt-Hours	EGS Share of Total Small Commercial Megawatt-Hours	EGS Share of Total Residential Megawatt-Hours	EGS Share of Total Small Commercial Megawatt-Hours
2015	1%	24%	35%	62%
2016	1%	23%	36%	64%
2017	1%	24%	36%	64%
2018	1%	21%	36%	61%
2019	1%	36%	36%	60%
2020	1%	36%	30%	60%
2021	1%	28%	27%	57%
2022	1%	22%	24%	52%
Standard Deviation (SD)	0%	6%	5%	4%
Average	1%	27%	33%	60%
Relative SD	0%	23%	15%	7%
Source: https://www.puc.pa.gov/filing-resources/reports/retail-choice-activity-reports/				

Q. ARE THERE ANY OTHER MAJOR OMISSIONS FROM THE LIST OF FACTORS CONSIDERED IN THE PROCUREMENT STUDY?

A. Yes, there is one other major factor that was acknowledged in the Procurement Study,[27] yet it was not included in the development of the class-based cost estimates. It may not be straightforward to quantify, but it should still be taken into consideration in qualitative decision making by the Commission. That other factor is the size of the load or the size of the tranche of each individual class load if UGI were to procure for residential and non-residential GSR-1 default service customers separately. The larger the size of the tranche and/or the larger the number of tranches being solicited in the same RFP, the more attractive it is for wholesale suppliers. Therefore, larger tranche

[27] Procurement Study, p. 16.

sizes and/or numbers attract more competitors and lower prices because suppliers spread the fixed costs associated with participating in the RFP over a larger MWh volume. In the extreme, a tranche may not receive any bids at all if it is perceived to be too small to bother with by wholesale suppliers.

Based on the load data provided by the Company in discovery, UGI's residential default service load (in annual MWh) is 2.7 times as large as the non-residential GSR-1 load as of the most recent 12-month period provided by the Company (May 2023 through April 2024).[28] Said another way, residential customers constitute 73 percent of the GSR-1 default service load while non-residential GSR-1 customers account for merely 27 percent. While combining the non-residential GSR-1 default service load with the residential default service load for procurement purposes benefits both customer classes in terms of making the volume attractive for FPFR suppliers, the non-residential GSR-1 class is clearly the larger beneficiary. Without the residential load, the non-residential GSR-1 default service load on a standalone basis would either attract no FPFR bidders or it would do so at a larger supplier embedded administrative cost. I note that the larger administrative cost that would be embedded in FPFR supplier bids would be in addition to the larger switching risk-related risk premium which would be embedded in non-residential FPFR contract bids. If the standalone non-residential GSR-1 default service load does not receive any (acceptable) FPFR contract bids, then non-residential GSR-1 default service customers would likely be forced into a spot market pricing or a block-and-spot arrangement, which would entail continuously incurring a large price risk and enduring volatile rates.

[28] Calculated from UGI's Response to OCA Set I, #13.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING UGI'S PROPOSAL TO CONDUCT A COMBINED PROCUREMENT PROCESS FOR THE TWO GSR-1 CUSTOMER GRUPS BUT SET A 10 PERCENT HIGHER EC RATE FOR RESIDENTIAL CUSTOMERS THAN FOR NON-RESIDENTIAL CUSTOMERS.

A. I recommend that the Commission reject this arbitrary and ad hoc price premium which the Company is proposing to impose on residential default service customers to the detriment of residential and to the benefit of non-residential GSR-1 customers. My recommendation is based on my conclusion that there is no basis for implementing the proposed 10 percent rate differential between residential and non-residential GSR-1 customers. For the reasons I explained in detail in this section of my Direct Testimony, the results and estimates in the Procurement Study cannot be relied upon to constitute such a basis because of all the flaws, inaccuracies, and biases inherent in the assumptions and methodology of the Procurement Study.

Since combining the loads of residential and non-residential GSR-1 customers benefits both customers classes by making UGI's GSR-1 default service load volume larger and more attractive to FPFR suppliers, but there is no basis to implement a rate differential between the two customer classes, I recommend that UGI maintain the status quo; i.e., continue to conduct a joint procurement process for the two GSR-1 customer classes, and also continue to set a single GSR-1 EC rate and a single GSR-1 PTC applicable to all (residential and non-residential) GSR-1 default service customers.

Q. IF THE COMMISSION WERE INCLINED TO APPROVE DIFFERENT EC RATES AND PTCs FOR RESIDENTIAL AND NON-RESIDENTIAL GSR-1 CUSTOMERS, HOW DO YOU RECOMMEND THAT UGI EFFECTUATE SUCH AN ARRANGEMENT?

A. Even though I am not recommending separate procurements or different rates for residential and non-residential GSR-1 default service customers, if the Commission were inclined to approve separate EC rates and PTCs for the two customer classes to ensure that each customer class incurs its true procurement cost and risk, I would recommend that the Company conduct separate procurements for the two customer classes and determine the respective EC rate and PTC for each customer class based on the respective procurement costs of each customer class. It would be unfair, unduly discriminatory, and a cost shift to residential default service customers if non-residential GSR-1 default service customers were to pay an arbitrarily determined lower rate than residential default service customers even though, for the reasons I explained above, non-residential GSR-1 default service customers are the larger beneficiaries of the joint procurement process. Even though this option would entail an estimated incremental administrative expense of $24,200 per year, this incremental expense does not appear excessive compared to the estimated annual GSR-1 administrative expense of $425,528 for DSP V, or compared to the projected increase of $221,783 in annual GSR-1 administrative expense from DSP IV to DSP V.[29]

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[29] UGI Electric Statement No. 3, p. 9, lines 16-20.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF UGI UTILITIES, INC. – ELECTRIC DIVISION FOR APPROVAL OF A DEFAULT SERVICE PLAN (DSP IV) FOR THE PERIOD OF JUNE 1, 2025 THROUGH MAY 31, 2029	**)**	**DOCKET NO. P-2024-3049343**

EXHIBIT ACCOMPANYING THE

DIRECT TESTIMONY

OF

SERHAN OGUR

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

August 2, 2024

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

UGI Utilities, Inc. - Electric Division
Docket No. P-2024-3049343
UGI Electric Default Service Plan
Responses to OCA Set I (1-16)
Delivered on July 29, 2024

Question 1

Request:

Item 1 references the Direct Testimony of UGI witness Mr. Jesse R. Tyahla.

1. Referencing page 3, lines 20 through 21.

a. Please list all cost or credit line items which are included in the "Other Costs" category in the Northbridge Group study.

b. Please list all cost and risk elements that are applicable to the cost of serving default service customers but which were excluded from the "cost of service" estimation in the Northbridge Group study.

c. Did the authors of the Northbridge Group study the shopping and switching characteristics of each customer class in GSR-1? If yes, please provide their findings.

d. Did the Northbridge Group study estimate the customer switching risk-related risk premium for each customer class? If yes, please provide these estimates and how each such estimate is calculated from raw data and underlying inputs and assumptions in live Excel spreadsheet format, with all formulae and references intact.

e. Did the Northbridge Group study factor the customer switching risk-related risk premium for each customer class into the relative "cost of service" price estimate of each respective customer class?

f. If the customer switching risk-related risk premium for each customer class were to be included in the relative "cost of service" price estimate of each respective customer class, in which direction and in what magnitude would UGI and/or the third-party consultants to which UGI commissioned this study expect that to change the relative cost of serving each customer class?

Response:

a. As noted in the Northbridge Group study, pages 11-12: "In sum, the "other costs" estimates for the UGI residential customer group and the UGI non-residential GSR-1 customer group represent the default service supply costs that are not

UGI Utilities, Inc. - Electric Division
Docket No. P-2024-3049343
UGI Electric Default Service Plan
Responses to OCA Set I (1-16)
Delivered on July 29, 2024

Question 1 (Continued)

captured in the energy, capacity, and NITS cost estimates, including costs that result from the risks associated with default service supply." By way of further response, please see the Appendix on page 21 of the study for a listing of data sources utilized in performing the relative cost analysis.

b. Please see the response to (a) above.

c. No specific shopping and switching characteristics of each customer class were identified for discussion in the Northbridge Group study.

d. Please see the response to (a) above.

e. Please see the response to (a) above.

f. Please see the response to (a) above.

Prepared by or under the supervision of: Jesse R. Tyahla

UGI Utilities, Inc. - Electric Division
Docket No. P-2024-3049343
UGI Electric Default Service Plan
Responses to OCA Set I (1-16)
Delivered on July 29, 2024

Question 12

Request:

Items 7 through 14 reference the Direct Testimony of UGI witness Mr. James M. Rouland.

12. Referencing page 22, lines 19-21.

a. Please explain why "GSR-2 customers represent significant volatility and risk for any supplier that would seek to provide UGI with GSR-2 supply" according to Mr. Rouland.

b. Please explain why "[t]his could result in high risk premiums or little to no supplier participation" according to Mr. Rouland.

c. Please explain why this could result in "potential for customer cross-subsidization" according to Mr. Rouland.

Response:

The GSR-2 rate group includes those commercial and industrial customers that are above a 100 kW demand split. As discussed in UGI Electric Statement No. 2, the Direct Testimony of James M. Rouland, page 22, lines 8-18, this customer group includes those customers that are often more sophisticated and often shop for their electricity. Given the mobility larger commercial and industrial customers - entering and leaving default service - wholesale supplier bids for fixed product offerings, such as that which is offered for GSR-1 customers, is likely to yield a high risk premium, if obtaining a bid at all, given the load variability inherent with this customer segment. These premium increases would be a result of wholesale suppliers attempting to protect themselves from the load variability with energy products they secure as a component of their product mix - some of which may be for block products or other structured, firm supply obligations which are at risk if the load obligation drops below the expected supply amount.

The statement made in UGI Electric Statement No. 2, the Direct Testimony of James M. Rouland, page 22, lines 20-22 and page 23, lines 1-2, were in reference to the Commission's Retail Market Investigation position with regard to implementation of a commercial and industrial customer demand split. Specifically, that without the demand split there was a risk that those customers that are both large in their relative consumption level and active in the retail market would increase the cost of fixed price default service

UGI Utilities, Inc. - Electric Division
Docket No. P-2024-3049343
UGI Electric Default Service Plan
Responses to OCA Set I (1-16)
Delivered on July 29, 2024

Question 12 (Continued)

rate offerings through wholesale supplier risk premiums, thereby causing smaller and less active retail market participant to pay for large customer's movements. Said another way, that larger commercial and industrial customers benefit from a fixed price offering at the cost of smaller less active commercial and industrial customers. In UGI Electric's case, the impact is greater as the GSR-1 rate group includes residential customers in additional to commercial and industrial customers at or below 100 kW.

Prepared by or under the supervision of: James M. Rouland

APPENDIX A

SUMMARY OF QUALIFICATIONS

for

SERHAN OGUR, Ph.D.

SERHAN OGUR, Ph.D.

Dr. Ogur is a Principal of Exeter Associates, Inc. with 23 years of experience in the energy industry specializing in organized wholesale (Regional Transmission Organization / Independent System Operator) and retail electricity markets. Dr. Ogur's diverse background comprises energy management and consulting; analysis, design, and reporting of RTO electricity markets and products; and state and federal regulation of electric utilities.

Dr. Ogur's coursework in graduate school focused on Microeconomic Theory, Game Theory, and Industrial Organization. His doctoral dissertation investigates imperfect competition in deregulated wholesale electricity markets and oligopolistic competition between private and public generators.

Education

Ph.D. (Economics), 2007
Northwestern University
Evanston, Illinois

B.A. (Economics), 1996
Bogazici University
Istanbul, Turkey

Previous Employment

2014-2015	Senior System Operator Fellon-McCord & Associates, LLC Louisville, KY
2005-2014	Senior Economist PJM Interconnection, LLC Audubon, PA
2001-2005	Economic Analyst Illinois Commerce Commission Springfield, IL

Professional Experience

Dr. Ogur's work at Exeter includes analysis of electricity supply contracts; utility rates and tariffs; energy markets and prices; power procurement; default electric service design; project evaluation; demand response opportunities; congestion hedging strategies; and price forecasting.

Prior to joining Exeter, Dr. Ogur's responsibilities at Fellon-McCord encompassed overseeing and performing the daily tasks of the "24/7" wholesale electricity desk, including all aspects of scheduling, managing, and monitoring direct market participant load and generation assets (mostly in ISO/RTO markets) as well as their settlements and custom reporting. He was also in charge of developing strategies and making recommendations, through

analytical, financial, and market research, for longer-term management of clients' load obligations and generation assets such as Auction Revenue Rights (ARR) nominations; participation in energy, ancillary services, and capacity markets; load forecasting; energy, basis, and capacity price forecasting; hedging; and peak load management. Dr. Ogur also served as the company's lead analyst in various special consulting projects.

In PJM Interconnection's Market Strategy and Market Analysis departments, Dr. Ogur was responsible for analyzing and reporting on all PJM-administered electricity market products, including day-ahead and real-time energy, operating reserve, regulation, synchronized reserve, virtual transactions, financial transmission rights, capacity, demand response, energy efficiency, and renewables. He was part of the team that developed the protocols and business rules for participation of energy efficiency in PJM markets as well as a lead reviewer for energy efficiency plans and post-installation measurement and verification (M&V) reports for PJM's capacity market auctions. He also has training and experience in PJM's stakeholder management process.

Dr. Ogur's responsibilities at the Illinois Commerce Commission (ICC) included monitoring all Illinois-related developments under federal jurisdiction, mostly Federal Energy Regulatory Commission (FERC) filings and rulings concerning major Illinois electric public utilities. In addition, Dr. Ogur reviewed all actions concerning Illinois public utilities at the FERC level (applications to join RTOs, market-based rate authority filings, merger applications, transmission rate cases, etc.), and developed positions and official comments for the consideration of the ICC to file in the related FERC dockets. Dr. Ogur also filed written testimony and served as staff witness (including standing cross-examination) in the ICC dockets establishing auction-based competitive wholesale energy procurement mechanisms for major Illinois electric public utilities.

Sample Major Publications and Reports

New Hampshire Solicitation and Procurement of Default Energy Service, prepared for the New Hampshire Department of Energy, March 2023 (with Matthew Hoyt, Olivia Kuykendall, Grace Koenig, and Cali Clark of Exeter Associates)

Review of the Non-Market-Based Services Riders Established by Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company and Associated Pilot Program, prepared for the Public Utilities Commission of Ohio in response to Case No. 22-391-EL-RDR, July 2023 (with Matthew Hoyt and Ari Weissfeld of Exeter Associates)

Retail Supply and Standard Offer Service Reform for Maine, prepared for Maine Office of the Public Advocate, February 2023 (with Steven Estomin, Matthew Hoyt, Olivia Kuykendall, Afton Hauer, and Cali Clark of Exeter Associates)

Expert Testimony

Before the Pennsylvania Public Utility Commission, Docket No. P-2024-3048592, Duquesne Light Company, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Pennsylvania Public Utility Commission, Docket No. P-2024-3047290, PPL Electric Utilities Corporation, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Pennsylvania Public Utility Commission, Docket No. P-2024-3046008, PECO Energy Company, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Pennsylvania Public Utility Commission, Docket No. P-2023-3039927, Pike County Light & Power Company, 2023, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Pennsylvania Public Utility Commission, Docket Nos. A-2023-3038771 *et al*, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company, 2023, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed public utility merger and acquisition issues.

Before the Pennsylvania Public Utility Commission, Docket Nos. P-2021-3030012, P-2021-3030013, P-2021-3030014 and P-2021-3030021, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company, 2022, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Ontario Superior Court of Justice, In the Matter of Just Energy Group Inc. et al, Court File No. CV-21-00658423-00CL, 2021, on behalf of the *Donin and Jordet* Plaintiffs. Testified on overcharges by a retail electric supplier in a class action suit with plaintiffs in 11 states in the U.S.

Before the Pennsylvania Public Utility Commission, Docket Nos. A-2021-3025659 and A-2021-3025662, Pike County Light & Power Company and Leatherstocking Gas Company, LLC, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed public utility merger and acquisition issues.

Before the U.S. District Court for the District of New Jersey, Civil Action No. 3:17-cv-02680-MAS- LHG, 2021, on behalf of Janet Rolland, et al. Testified on systematic overcharges by a retail electric supplier in a class action suit with plaintiffs in eight states.

Before the Pennsylvania Public Utility Commission, Docket No. P-2020-3022988, Pike County Light & Power Company, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Pennsylvania Public Utility Commission, Docket No. P-2020-3019907, UGI Utilities, Inc. – Electric Division, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Pennsylvania Public Utility Commission, Docket No. P-2020-3019522, Duquesne Light Company, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Pennsylvania Public Utility Commission, Docket Nos. P-2020-3019383 and P-2020-3019384, Citizens' Electric Company of Lewisburg, PA and Wellsboro Electric Company, 2020, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Pennsylvania Public Utility Commission, Docket No. P-2016-2534980, PECO Energy Company, 2016, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed default service issues.

Before the Illinois Commerce Commission, Docket No. 05-0159, Commonwealth Edison Company, 2005, on behalf of the Staff of Illinois Commerce Commission. Testimony addressed default service design and competitive procurement issues.

Before the Illinois Commerce Commission, Docket Nos. 05-0160, 05-0161, and 05-0162 (Consolidated), Central Illinois Light Company d/b/a AmerenCILCO, 2005, on behalf of the Staff of Illinois Commerce Commission. Testimony addressed default service design and competitive procurement issues.

Before the Illinois Commerce Commission, Docket No. 02-0428, Central Illinois Light Company and Ameren Corporation, 2002, on behalf of the Staff of Illinois Commerce Commission. Testimony addressed competition issues in a utility merger case.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Program for the Period June 1, 2025 Through May 31, 2029	: : : :	Docket No. P-2024-3049343

VERIFICATION

I, Serhan Ogur, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 1, 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: August 2, 2024

Signature:

Serhan Ogur

Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-2690

COMMONWEALTH OF PENNSYLVANIA

OCA Statement 1-R 10/1/24 G.J.

PATRICK M. CICERO
Consumer Advocate

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
Harrisburg, Pennsylvania 17101-1923
(717) 783-5048
(800) 684-6560

@pa_oca
/pennoca
FAX (717) 783-7152
consumer@paoca.org
www.oca.pa.gov

August 30, 2024

Via Electronic Mail
The Honorable Dennis J. Buckley
The Honorable Alphonso Arnold III
Office of Administrative Law Judge
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division For Approval of its Default Service Program for the Period from June 1, 2025 through May 31, 2029
Docket No. P-2024-3049343

Dear Judge Buckley and Judge Arnold:

Attached for electronic filing please find a copy of the Rebuttal Testimony being submitted on behalf of the Office of Consumer Advocate in the above-referenced proceeding, as follows:

OCA Statement 1R: Rebuttal Testimony of Dr. Serhan Ogur

Copies have been served on the parties as indicated on the enclosed Certificate of Service.

Respectfully submitted,

/s/ Harrison W. Breitman
Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
HBreitman@paoca.org

Enclosures
cc: PUC Secretary Rosemary Chiavetta (Letter and Certificate of Service Only)
Certificate of Service

CERTIFICATE OF SERVICE

Petition of UGI Utilities, Inc. – Electric Division For Approval of its Default Service Program for the Period from June 1, 2025 through May 31, 2029	: : : :	Docket No. P-2024-3049343

I hereby certify that I have this day served a true copy of the following document, the Office of Consumer Advocate's Rebuttal Testimony as follows:

OCA Statement 1R: Rebuttal Testimony of Dr. Serhan Ogur

upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below. This document was filed electronically on the Commission's electronic filing system.

Dated this 30th day of August 2024.

SERVICE BY E-MAIL ONLY

Lindsay Berkstresser, Esquire
UGI Utilities Inc.
500 North Gulph Rd
King of Prussia PA 19406
berkstresserl@ugicorp.com
Counsel for UGI Utilities Inc.

Anthony D. Kanagy, Esquire
Nicholas A. Stobbe, Esquire
17 North Second St
Harrisburg PA 17101
aganagy@postschell.com
Counsel for UGI Utilities Inc.

Todd Stewart
Hawke, McKeon & Sniscak LLP
100 N. 10th Street
Harrisburg, PA 17101
tsstewart@hmslegal.com
Counsel for Penn Renewables

Steven Gray, Esquire
Senior Attorney
Assistant Small Business Advocate
Office of Small Business Advocate
555 Walnut Street, 1st Floor
Forum Place
Harrisburg, Pennsylvania 17101
sgray@pa.gov
Counsel for OSBA

Devin T. Ryan, Esquire
Post and Schell PC
One Oxford Centre
301 Grant St suite 3010 Pittsburgh PA 15219
dryan@postschell.com
Counsel for UGI Utilities Inc.

/s/*Harrison W. Breitman*

Harrison W. Breitman
Assistant Consumer Advocate PA
Attorney I.D. # 320580
HBreitman@paoca.org

Counsel for:

Office of Consumer Advocate 555 Walnut Street
5th Floor, Forum Place Harrisburg, PA 17101-1923

Date: August 30, 2024

STATEMENT NO. 1R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF UGI UTILITIES, INC. – ELECTRIC DIVISION FOR APPROVAL OF A DEFAULT SERVICE PLAN (DSP V) FOR THE PERIOD OF JUNE 1, 2025 THROUGH MAY 31, 2029	**)** **)** **)** **)** **)**	**DOCKET NO. P-2024-3049343**

REBUTTAL TESTIMONY

OF

SERHAN OGUR

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

August 30, 2024

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. UGI'S PROPOSED DEFAULT SERVICE PRODUCT PORTFOLIO 2

II. PROCUREMENT STUDY 4

III. GSR-1 VS. GSR-2 DESIGNATION BASED ON SUPPLY PEAK LOAD IMPACTS ...7

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Serhan Ogur. I am a Principal and Senior Economist at Exeter Associates, Inc. My office is located at 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes. I submitted Direct Testimony on August 2, 2024, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

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

A. My Rebuttal Testimony responds to certain issues raised by the Office of Small Business Advocate ("OSBA") witness Mr. Mark D. Ewen in his Direct Testimony. These issues relate to (i) the proposed procurement strategy of UGI Utilities, Inc. – Electric Division ("UGI" or "UGI Electric" or "Company") for GSR-1 customers (i.e., residential customers, and non-residential customers with supply peak load impact up to 100 kilowatts); and (ii) the Company's proposed combined procurement yet separate rates for the residential and non-residential customer subgroups of the GSR-1 rate class. I also address Penn Renewables, LLC ("Penn Renewables") witness Mr. James L. Crist pertaining to his objections to the Company's proposal to assign customers to the GSR-1 and GSR-2 procurement groups based on the supply peak load impact criterion.

II. UGI'S PROPOSED DEFAULT SERVICE PRODUCT PORTFOLIO

Q. PLEASE DESCRIBE THE GSR-1 DEFAULT SERVICE SUPPLY PORTFOLIO PROPOSED BY UGI FOR DEFAULT SERVICE PLAN V ("DSP V").

A. UGI proposes to procure approximately 24 percent of the GSR-1 energy supply through laddered 24-month around-the-clock ("ATC") energy blocks (20 megawatts ["MW"] in total starting on November 1, 2025; 10 MW before November 1, 2025), and self-supply other products and services (capacity, transmission, ancillary services, congestion, alternative energy credits ["AECs"]) needed to provide full-requirements default service to residential and small commercial customers. The Company proposes to procure the remaining approximately 76 percent of GSR-1 full-requirements (with certain exceptions, such as non-market-based transmission service [NMB] costs) supplies through competitively procured, laddered, 12-month fixed-price, full-requirements ("FPFR") contracts. Each 12-month FPFR contract would represent one half of the residential and small commercial default service supply load after such load is offset by energy blocks and small, long-term supply arrangement between UGI and the Allegheny Electric Cooperative, Inc.[1]

Q. WHAT IS MR. EWEN'S ASSESSMENT OF UGI'S PROPOSED GSR-1 DEFAULT SERVICE PODUCT PORTFOLIO?

A. Mr. Ewen posits that:

- It is unclear whether the changes in the supply portfolio and procurement approach proposed by UGI from DSP IV to DSP V would translate into lower premiums and more rate stability;
- Given the Company's relatively small size and ongoing issues with supplier participation/competition, UGI Electric's procurement approach is not unreasonable in terms of balancing the goals of increasing the load procured from full-requirements contracts while keeping administrative costs and supplier risk at manageable levels, and;

[1] Petition, paragraph 46.

- Implementing more abrupt modifications to the Company's existing procurement approach, for example eliminating the block products entirely, may not be feasible or prudent at this time.[2]

Q. PLEASE STATE YOUR AGREEMENTS AND DISAGREEMENTS WITH MR. EWEN'S ASSESSMENT.

A. I concur with Mr. Ewen that it is unclear whether the changes in the supply portfolio and procurement approach proposed by UGI from DSP IV to DSP V would translate into lower premiums and more rate stability. While I do not necessarily disagree with Mr. Ewen that abrupt modifications to UGI's existing procurement approach could be infeasible or imprudent, I disagree that eliminating the block products entirely would constitute an abrupt change to the existing approach. I also disagree that eliminating the block products entirely would not be feasible or prudent at this time. Mr. Ewen does not explain why eliminating the block products entirely would be an abrupt modification to the existing approach or why it would not be feasible or prudent at this time. As I also explained in my Direct Testimony, replacing the 24-month block purchases proposed by UGI with 24-month FPFR contracts would increase the total number of megawatt-hours ("MWh") to be procured via FPFR tranches, and FPFR contracts with larger sales volumes would be more appealing to wholesale suppliers than FPFR contracts with smaller sales volumes.[3]

Q. HAVE YOU CHANGED YOUR RECOMMENDATIONS IN YOUR DIRECT TESTIMONY AFTER REVIEWING MR. EWEN'S DIRECT TESTIMONY?

A. No. In my Direct Testimony, I recommended that the residential and small commercial default service supply portfolio consist of 100 percent 24-month FPFR contracts, after a 12-month FPFR contract and an 18-month FPFR contract as "catch-up" procurements to

[2] OSBA Statement No. 1, p. 6, lines 1-17.
[3] OCA Statement No. 1, p. 22, lines 9-12.

start DSP V,[4] and provided the basis for my recommendation.[5] My recommendation remains the same after reviewing Mr. Ewen's Direct Testimony.

II. PROCUREMENT STUDY

Q. PLEASE DESCRIBE THE CONCLUSIONS AND RECOMMENDATIONS OF THE AUTHORS OF THE "PROCUREMENT STUDY" AND STATE WHAT UGI PROPOSED IN THE DSP V FILING.

A. As one of the conditions of UGI's DSP IV settlement, UGI agreed to file a study of the relative cost of default service supplies for GSR-1 residential and non-residential customers.[6] The Company commissioned the study (hereafter, the "Procurement Study") to the Northbridge Group and the resulting report is provided in UGI's DSP V filing.

The authors of the Procurement Study concluded that (1) residential GSR-1 customers would be between 8 percent and 9 percent more costly (on a $/MWh of load basis) to serve than non-residential GSR-1 customers;[7] and (2) conducting separate procurements for the residential and non-residential GSR-1 customer classes would increase UGI's annual administrative costs by $24,200.[8] The authors of the Procurement Study did not make explicit recommendations. They stated that "maintaining UGI's combined GSR-1 group may be the more prudent approach," and they outlined a cost allocation approach which the Commission could consider. That cost allocation approach is determining the Energy Cost ("EC") rate (in $/MWh), which is the projected direct and indirect purchased power costs incurred by UGI to acquire electric supply for the GSR-1 group, and then setting residential and non-residential GSR-1 EC rates two percent higher and seven percent lower, respectively, than this combined EC rate.

[4] OCA Statement No. 1, p. 16, lines 2-7.
[5] OCA Statement No. 1, pp. 19-20.
[6] UGI Electric Exhibit JRT-2, Appendix A ("Procurement Study"), p.1.
[7] Procurement Study, p. 2.
[8] Procurement Study, p. 17.

UGI proposed to conduct combined procurements for the entire GSR-1 group and apply the residential and non-residential allocation factors of 1.02 and 0.93, respectively, to the EC rate component in determining separate EC rates for residential and non-residential GSR-1 default service customers.

Q. WHAT IS MR. EWEN'S ASSESSMENT OF THE PROCUREMENT STUDY AND UGI'S PROPOSAL?

A. Mr. Ewen finds the Procurement Study's methodology and conclusion to be reasonable in terms of separate versus combined procurements for residential and non-residential GSR-1 customers. Mr. Ewen supports the approach of UGI continuing its joint procurement strategy while assigning separate GSR-1 rates to residential and non-residential customers.[9]

Q. DO YOU AGREE WITH MR. EWEN'S ASSESSMENT?

A. The only assessment of Mr. Ewen's with which I agree is that UGI should continue to conduct joint procurements for the residential and non-residential GSR-1 customers. I disagree that the Procurement Study's methodology and conclusions are reasonable. In my Direct Testimony I demonstrated in detail the assumptions and omissions in the Procurement Study which make its methodology flawed, and its results and findings unreliable.[10] The most important flaw in the Procurement Study's assumptions and methodology is that it includes the factors and cost elements which make the non-residential GSR-1 customers less costly to serve (e.g., capacity, transmission, and possibly load shape) while ignoring the factors and cost elements which make the non-residential GSR-1 customers more costly to serve (e.g., higher switching risk, small size of the load). These methodological flaws and omissions bias the estimates in the findings

[9] OSBA Statement No. 1, p. 8, lines 7-12.
[10] OCA Statement No. 1, pp. 25-25.

in favor of non-residential GSR-1 customers, and thus the Procurement Study fails to qualify to form the basis for setting different generation rates for residential and non-residential GSR-1 customers.

I note that Mr. Ewen acknowledges the importance of switching risk in the cost of serving load by recognizing that "[w]hen shopping rates vary significantly over time, more risk is associated with longer-term procurements of electricity supply."[11] However, his claim that "[d]ata segregated by residential and non- residential GSR-1 customers are not available" is incorrect.[12] As I also depicted in my Direct Testimony, the Pennsylvania Public Utility Commission ("Commission") publishes customer class specific shopping and switching data in its annual Retail Choice Activity Reports.[13] An analysis of these reports (such as the analysis which I have provided in my Direct Testimony) reveals that UGI's non-residential GSR-1 customers have much higher shopping rates (fluctuating between 21 percent and 36 percent on an annual basis from 2015 through 2022, averaging 27 percent in terms of MWh volume) than UGI's residential customers (which have a shopping rate of merely one percent that is unchanged over the same time-period). More importantly, the switching risk of UGI's small commercial customers is many times larger than the switching risk of UGI's residential customers, as measured by the relative standard deviation of each customer subgroup. Similar to the authors of the Procurement Study, Mr. Ewen appears to ignore the effect of switching risk on FPFR bids and thus respective costs of serving residential and non-residential GSR-1 customers when he endorses the methodology and conclusions of the Procurement Study.

Mr. Ewen also acknowledges that "[w]ith separate procurements for residential and non-residential GSR-1 customers, the bids may be uncompetitive, or suppliers may

[11] OSBA Statement No. 1, p. 5, lines 16-18.
[12] OSBA Statement No. 1, p. 5, lines 14-15.
[13] OCA Statement No. 1, p. 30 line 21 through p. 32, line 5.

not bid at all, given the smaller amounts of supply,"[14] and that "[t]he Company's GSR-1 non- residential customer group would have the smallest aggregate number of megawatt-hours of default service supply per solicitation for any single customer group among Pennsylvania EDCs [Electric Distribution Companies]."[15] However, in his endorsement of the Procurement Study's methodology and conclusions, he seems to ignore this additional cost element which the non-residential GSR-1 customer segment would face in a standalone procurement.

Q. HAVE YOU CHANGED YOUR RECOMMENDATIONS IN YOUR DIRECT TESTIMONY AFTER REVIEWING MR. EWEN'S DIRECT TESTIMONY?

A. No. I continue to recommend that UGI maintain the status quo; i.e., continue to conduct a joint procurement process for the two GSR-1 customer classes, and also continue to set a single GSR-1 EC rate and a single GSR-1 Price-to-Compare applicable to all (residential and non-residential) GSR-1 default service customers.

III. GSR-1 VS. GSR-2 DESIGNATION BASED ON SUPPLY PEAK LOAD IMPACTS

Q. PLEASE DESCRIBE THE CRITERION BY WHICH UGI PROPOSED TO CLASSIFY AN ACCOUNT AS GSR-1 OR GSR-2, AND ITS RATIONALE FOR PROPOSING THAT CRITERION.

A. UGI proposed to classify a customer account as GSR-1 or GSR-2 according to the "supply peak load impact" criterion.[16] Supply peak load impact will be determined on a customer's (including a net metering 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.[17] Customers with a supply peak load

[14] OSBA Statement No. 1, p. 7, lines 28-30.
[15] OSBA Statement No. 1, p. 7, line 33 through p. 8, line 3.
[16] Petition of UGI Utilities, Inc. – Electric Division For Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029 ("Petition"), paragraph 35.
[17] Petition, Appendix A, ProForma Tariff Supplement to UGI Electric Pa. P.U.C. No. 6, Page no. 39.

impact below 100 kW will be classified as GSR-1, and customers with a supply peak load impact that is greater than or equal to 100 kW will be classified as GSR-2. This approach would include reviewing net metering customer-generators based upon their net supply peak load impact.[18] In other words, both a non-residential customer with a peak demand of 100 kW or above, and a non-residential customer-generator with a peak injection into the Company's distribution grid of 100 kW or above will be classified as GSR-2 customers because both have respective supply peak load impacts of 100 KW or above. This clarification is intended to separate portfolio risk management and cost impacts to default service procurement activities, and to address potential small versus medium/large cross-subsidy concerns while providing clarity for all customers.[19]

UGI witness Mr. James M. Rouland draws a parallel between large commercial and industrial customers and large net metering customers, stating that they have similarly substantial grid impacts, and both have similar sophistication and likelihood of shopping (which, in the case of large net metering customers, Mr. Rouland refers to as wholesale market participation). According to Mr. Rouland, this assignment will appropriately ensure that GSR-1 customers will not be negatively impacted by the market activities of large customer-generators.[20]

Q. PLEASE SUMMARIZE MR. CRIST'S RESPONSE TO UGI'S PROPOSAL.

A. Mr. Crist states that UGI should not be permitted to use the proposed methodology to classify customers into the GSR-1 and GSR-2 procurement groups.[21] He provides two reasons for opposing the Company's proposed classification methodology. First, he posits that he is not aware of any other Pennsylvania EDC using peak supply to establish

[18] Petition, paragraph 35.
[19] Petition, paragraph 35.
[20] UGI Electric Statement No. 2, p. 29, line 17 through p. 30, line 5.
[21] Penn Renewables Statement No. 1, p. 20, line 17.

commodity rates that are paid to customer-generators.[22] Second, he is concerned about the proposed methodology because, according to Mr. Crist, when GSR-2 customer-generators produce power for export, PJM hourly price (Locational Marginal Price, or "LMP") for the UGI zone, and thus the customer-generator's compensation, declines. Mr. Crist claims that GSR-2 customers would pay more than the amount that net metered customer-generators will be paid for excess generation for the same hour.[23] Finally, Mr. Crist recommends that, if the Commission wishes to permit UGI to offer volatile variable rates (i.e., hourly LMP as determined by PJM) to GSR-2 customer-generators, then the GSR-2 threshold should be increased from 100 kW to 3 MW, which he claims would be in line with the Alternative Energy Portfolio Standards Act ("AEPS Act".)[24]

Q. PLEASE RESPOND TO MR. CRIST'S RECOMMENDATIONS AND REASONING.

A. I disagree with Mr. Crist's recommendation, and his associated stated reasons, that the classification of customers into GSR-1 and GSR-2 procurement groups be made based exclusively on a customer's peak demand, regardless of a customer-generator's maximum injection into the Company's distribution grid. I also disagree with Mr. Crist's recommendation that the threshold for an account to be classified as GSR-2 be raised from 100 kW to 3 MW if the Commission authorizes UGI to compensate GSR-2 customer-generators based on LMP.

First, each Pennsylvania EDC has a different default service procurement grouping reflecting the criteria which make the most logical sense for that EDC's customer and load characteristics. For example, some EDCs procure for residential and small commercial default service customers jointly, while others do so separately. Each

[22] Penn Renewables Statement No. 1, p. 20, lines 15-17.
[23] Penn Renewables Statement No. 1, p. 20, line 19 through p. 21, line 10.
[24] Penn Renewables Statement No. 1, p. 28, lines 14-19.

EDC also has a different peak demand cutoff for small commercial, medium commercial, and large commercial and industrial procurement group designations. If an EDC does not use the same classification methodology proposed by UGI, that is likely because another methodology better fits its needs and customer characteristics. If other EDCs did not propose a procurement group cutoff based on both demand and supply peak cutoff, that is likely because their systems do not have as much pending customer-generator capacity relative to their overall customer loads.

Second, it is a natural consequence of PJM's LMP construct that, all else equal, as supply increases, price falls; similarly, as demand increases, price rises. By Mr. Crist's logic, any generator could claim a higher payment rate than LMP because in the absence of that generator's output, the market price would be higher. This would be a self-conflicting element of the LMP construct because payments from load would not be sufficient to pay the resources. The LMP in any given hour in a specific location (e.g., UGI zone) is determined by the intersection point of supply and demand, and all resources are paid, and all loads pay, that same LMP. Therefore, Mr. Crist's concern is not a flaw of the compensation mechanism design for exports by customer-generators; it merely reflects the fundamental principles and rules of PJM's LMP construct in which UGI operates. In addition, Mr. Crist's concerns with the GSR-2 customer-generator compensation mechanism has no relationship with the methodology by which customers are classified into the GSR-1 and GSR-2 procurement groups, and Mr. Crist does not establish a relationship between these two concepts.

Third, and similarly, what GSR-2 customers pay for electricity and how that may differ from the compensation rate for a customer-generator's exports has no relationship with the criterion according to which customers are classified into the GSR-1 and GSR-2 procurement groups, and Mr. Crist does not establish a relationship between these two

concepts. If there is a discrepancy between what GSR-2 customers pay for electricity and the compensation rate for a customer-generator's exports, and such discrepancy violates the Commission's rules, such discrepancy should be addressed on its own merits without deviating from a proper and logical customer classification methodology. Assigning large supply peak load impact customer-generators to the GSR-1 procurement group just because Mr. Crist perceives GSR-1 rates to be higher than GSR-2 rates on average, or because GSR-1 customers are offered fixed rates but GSR-2 customers are not, is not a fair or proper remedy.

Finally, raising the threshold for an account to be classified as GSR-2 from 100 kW to 3 MW if the Commission authorizes UGI to compensate GSR-2 customer-generators based on LMP is not logical or acceptable. It is nothing more than conflating two unrelated issues and attempting to substitute one as a remedy for another without any justification and without any regard to the negative effects of such an action on the GSR-1 customers under the current definition of GSR-1 (i.e., residential customers and small commercial customers with supply peak load impacts less than 100 kW).

Q. PLEASE EXPLAIN THE EFFECT OF INCLUDING LARGE CUSTOMER-GENERATORS IN THE GSR-1 PROCUREMENT GROUP ON RESIDENTIAL CUSTOMERS.

A. The inclusion of large customer-generators in the GSR-1 procurement group would bundle residential customers (and truly small commercial customers, i.e., which have supply peak load impacts less than 100 kW) with more sophisticated, large customer-generators in the same FPFR contract procurements. This would negatively affect residential default service customers in two ways. First, because the more sophisticated, large customer-generators would entail higher switching risk for the FPFR suppliers, the FPFR suppliers would either build larger risk premiums into their FPFR contract bids or

shy away from participating in the FPFR auctions. This would have the likely effect of higher Price to Compares ("PTCs") and/or more volatile rates for residential customers due to the inclusion of large customer-generators in the GSR-1 procurement group. In addition, large customer-generators would receive the higher PTC, which would have been inflated simply by their mere participation and switching risk, for their exports, which in turn would be recovered from all GSR-1 default service customers, most of which are residential customers. Second, even the large customer-generators that stay on default service constitute volumetric risk for FPFR suppliers because of the uncertainty surrounding the level and profile of on-site generation (e.g., outages, in-service dates of on-site generators that are in UGI's distribution interconnection queue). Similar to switching risk, this volumetric risk would prompt the FPFR suppliers to either build larger risk premiums into their FPFR contract bids or shy away from participating in the FPFR auctions, resulting in higher PTCs and/or more volatile rates for residential customers.

Q. PLEASE STATE YOUR CONCLUSION AND RECOMMENDATION AFTER REVIEWING THE COMPANY'S PROPOSAL AND MR. CRIST'S OBJECTION TO IT.

A. For the reasons I explained above, I concur with the Company's proposed methodology of assigning customers to the GSR-1 and GSR-2 procurement groups according to supply peak load impact, and its rationale for it. I find Mr. Crist's objections to the Company's proposal unconvincing and recommend that the Commission dismiss Mr. Crist's objections and recommendations.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

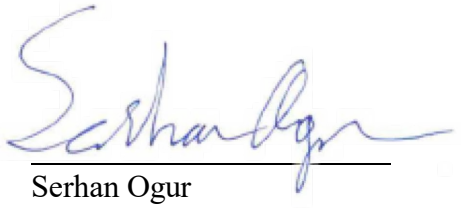
BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Program for the Period June 1, 2025 Through May 31, 2029	: : : :	Docket No. P-2024-3049343

VERIFICATION

I, Serhan Ogur, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement 1R, 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: August 30, 2024

Signature: 

Serhan Ogur

Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-2690

COMMONWEALTH OF PENNSYLVANIA

OCA Statement 1-SR 10/1/24 G.J.

PATRICK M. CICERO
Consumer Advocate

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
Harrisburg, Pennsylvania 17101-1923
(717) 783-5048
(800) 684-6560

@pa_oca
/pennoca
FAX (717) 783-7152
consumer@paoca.org
www.oca.pa.gov

September 25, 2024

Via Electronic Mail
The Honorable Dennis J. Buckley
The Honorable Alphonso Arnold III
Office of Administrative Law Judge
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division For Approval of its Default Service Program for the Period from June 1, 2025 through May 31, 2029
Docket No. P-2024-3049343

Dear ALJs Buckley and Arnold:

Please find enclosed a copy of the Surrebuttal Testimony being submitted on behalf of the Office of Consumer Advocate in the above-referenced proceeding, as follows:

OCA Statement 1SR: Surrebuttal Testimony of Serhan Ogur
(Public and **CONFIDENTIAL** Versions)

Copies have been served on the parties as indicated on the enclosed Certificate of Service.

Sincerely,

/s/*Harrison W. Breitman*
Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
HBreitman@paoca.org

Enclosures
cc: PUC Secretary Rosemary Chiavetta (Letter and Certificate of Service Only)
Certificate of Service

CERTIFICATE OF SERVICE

Petition of UGI Utilities, Inc. – Electric Division For Approval of its Default Service Program for the Period from June 1, 2025, through May 31, 2029	: : : :	Docket No. P-2024-3049343

I hereby certify that I have this day served a true copy of the following document:

OCA Statement 1SR: Surrebuttal Testimony of Dr. Serhan Ogur)
(Public and **CONFIDENTIAL** Versions)

upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below. This document was filed electronically on the Commission's electronic filing system.

Dated this 25th day of September, 2024.

SERVICE BY E-MAIL ONLY

Lindsay Berkstresser, Esquire
UGI Utilities Inc.
500 North Gulph Rd
King of Prussia PA 19406
berkstresserl@ugicorp.com
Counsel for UGI Utilities Inc.

Anthony D. Kanagy, Esquire
Nicholas A. Stobbe, Esquire
17 North Second St
Harrisburg PA 17101
akanagy@postschell.com
nstobbe@postschell.com
Counsel for UGI Utilities Inc.

Todd Stewart
Hawke, McKeon & Sniscak LLP
100 N. 10th Street
Harrisburg, PA 17101
tsstewart@hmslegal.com
Counsel for Penn Renewables

Counsel for:
Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923

Steve Gray
Office of Small Business Advocate
Forum Place
555 Walnut Street, 1st Floor Harrisburg,
Pennsylvania 17101
Sgray@pa.gov
Counsel for OSBA

Devin T. Ryan, Esquire
Post and Schell PC
One Oxford Centre
301 Grant St suite 3010
Pittsburgh PA 15219
dryan@postschell.com
Counsel for UGI Utilities Inc.

/s/*Harrison W. Breitman*
Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
HBreitman@paoca.org

Date: September 25, 2024

STATEMENT NO. 1SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF UGI UTILITIES, INC. – ELECTRIC DIVISION FOR APPROVAL OF A DEFAULT SERVICE PLAN (DSP V) FOR THE PERIOD OF JUNE 1, 2025 THROUGH MAY 31, 2029	**)))))**	**DOCKET NO. P-2024-3049343**

SURREBUTTAL TESTIMONY

OF

SERHAN OGUR

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

CONFIDENTIAL VERSION

SEPTEMBER 25, 2024

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. UGI'S PROPOSED DEFAULT SERVICE PRODUCT PORTFOLIO 2

III. PROCUREMENT STUDY 14

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Serhan Ogur. I am a Principal and Senior Economist at Exeter Associates, Inc. My office is located at 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes. I submitted Direct Testimony and Rebuttal Testimony in this proceeding on August 2, 2024 and on August 30, 2024, respectively, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

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

A. My Surrebuttal Testimony responds to certain issues raised by UGI Utilities, Inc. – Electric Division ("UGI" or "UGI Electric" or "Company") witnesses Mr. James M. Rouland, and Mr. Jesse R. Tyahla in their respective Rebuttal Testimonies; and by the Office of Small Business Advocate ("OSBA") witness Mr. Mark D. Ewen in his Rebuttal Testimony. These issues relate to (i) the proposed procurement strategy of UGI for GSR-1 customers (i.e., residential customers, and non-residential customers with supply peak load impact up to 100 kilowatts); and (ii) the Company's proposed combined procurement yet separate rates for the residential and non-residential customer subgroups of the GSR-1 rate class.

II. UGI'S PROPOSED DEFAULT SERVICE PRODUCT PORTFOLIO

Q. PLEASE DESCRIBE THE GSR-1 DEFAULT SERVICE SUPPLY PORTFOLIO PROPOSED BY UGI FOR DEFAULT SERVICE PLAN V ("DSP V").

A. UGI proposed to procure approximately 24 percent of the GSR-1 energy supply through laddered 24-month around-the-clock ("ATC") energy blocks (20 megawatts ["MW"] in total starting on November 1, 2025; 10 MW before November 1, 2025), and self-supply other products and services (capacity, transmission, ancillary services, congestion, alternative energy credits) needed to provide full-requirements default service to residential and small commercial customers. The Company proposes to procure the remaining approximately 76 percent of GSR-1 full-requirements (with certain exceptions, such as non-market-based transmission service costs) supplies through competitively procured, laddered, 12-month fixed-price, full-requirements ("FPFR") contracts. Each 12-month FPFR contract would represent one half of the residential and small commercial default service supply load after such load is offset by energy blocks and small, long-term supply arrangement between UGI and the Allegheny Electric Cooperative, Inc.[1]

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN AN FPFR CONTRACT AND AN ATC BLOCK.

A. An FPFR contract obligates the seller to satisfy a specified percentage (tranche) of all the applicable default service customers' supply requirements in every hour of the delivery period, regardless of the default service customers' instantaneous changes in energy consumption, regardless of how frequently customers switch to or from default service, and regardless of how the seller's cost to satisfy its supply obligation may change.[2] The

[1] Petition, paragraph 46.
[2] UGI Electric Exhibit JRT-2, Attachment A, page 3, footnote 5.

FPFR contract suppliers bid a dollar-per-megawatt-hour ("MWh") price to supply all generation products (with certain exceptions) required to serve their share of load – energy, capacity, transmission, ancillary services, alternative energy credits ("AECs"). FPFR contract suppliers are exposed to the volumetric risk of uncertain load responsibility while default service customers are insulated from this risk. An ATC block contract obligates the seller to provide a fixed quantity of energy (e.g., 10 MW) in each hour of a specified time period (e.g., June 2025; June 1, 2025 through May 31, 2027) at a predetermined delivery point (e.g., PJM Western Hub, UGI Zone). Unlike an FPFR contract, an ATC block contract seller's energy delivery obligation does not fluctuate with default service load. Another major difference between these two types of contracts is that an ATC block contract only requires the delivery of energy while an FPFR contract is for delivery of full requirements of default service customers including energy as well as other attributes and line items such as capacity, transmission, ancillary services, and AECs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING UGI'S PROPOSED GSR-1 DEFAULT SERVICE PODUCT PORTFOLIO.

A. In my Direct Testimony, I recommended that the residential and small commercial default service supply portfolio consist of 100 percent 24-month FPFR contracts, after a 12-month FPFR contract and an 18-month FPFR contract as "catch-up" procurements to start DSP V,[3] and provided the basis for my recommendation.[4]

Q. HOW DID MR. ROULAND RESPOND TO YOUR RECOMMENDATION?

A. Mr. Rouland summarized my four-fold rationale for my GSR-1 default service product portfolio recommendation as follows: (i) improved rate stability; (ii) reduced

[3] OCA Statement No. 1, p. 16, lines 2-7.
[4] OCA Statement No. 1, pp. 19-20.

administrative and operational burden to the Company; (iii) larger supply amount per tranche bid; and (iv) greater overlap into UGI's subsequent default service plan.[5] While Mr. Rouland concurs that my recommended portfolio consisting exclusively of 24-month FPFR contracts would provide enhanced rate stability compared to UGI's proposed portfolio,[6] he opposes the adoption of my recommended portfolio,[7] citing four reasons. First, Mr. Rouland states that the Company's proposed product mix provides most of the benefits I highlighted in support of my proposed portfolio, but also includes additional benefits such as likely lower supplier risk premiums, increased product diversity aimed at enticing more suppliers to bid, and what he claims to be a greater tranche size for FPFR products.[8] Mr. Rouland asserts that my recommended portfolio consisting exclusively of 24-month FPFR contracts would provide enhanced rate stability mainly because of the term of the contract, and not necessarily because of the nature of FPFR contracts,[9] though he does not clarify how that is relevant or how that takes away from the rate stability which customers would enjoy. Second, Mr. Rouland posits that my proposal fully relies upon relatively illiquid and high bid premium products through the 100% use of a longer-term 24-month FPFR contracts.[10] Third, Mr. Rouland seems to acknowledge that my proposal would result in reduced administrative and operational burdens for UGI, but he claims that such process improvements and solicitation simplifications would be relatively minor and associated savings would be minimal.[11] Finally, Mr. Rouland states his disagreement with my claim that my proposal would result in greater supply per tranche. According to Mr. Rouland, the FPFR tranche size under my proposal would be

[5] UGI Electric Statement No. 2-R, page 6, lines 4-10.
[6] UGI Electric Statement No. 2-R, page 6, lines 19-20.
[7] UGI Electric Statement No. 2-R, page 6, lines 12-14.
[8] UGI Electric Statement No. 2-R, page 6, lines 14-18.
[9] UGI Electric Statement No. 2-R, page 6, lines 19-21.
[10] UGI Electric Statement No. 2-R, page 7, lines 15-16.
[11] UGI Electric Statement No. 2-R, page 8, lines 5-9.

25 percent of the GSR-1 default service load while it would be 38 percent of the GSR-1 load under UGI's proposed product portfolio.[12] While he does not state it definitively, Mr. Rouland appears to continue to recommend the adoption of the GSR-1 default service product portfolio which was proposed in the Company's Petition.

Q. PLEASE COMMENT ON MR. ROULAND'S ASSERTION THAT REDUCED ADMINISTRATIVE AND OPERATIONAL BURDENS RESULTING FROM YOUR PROPOSED PORTFOLIO WOULD BE RELATIVELY MINOR.

A. UGI is a small utility with a relatively small amount of GSR-1 default service load compared to its larger peers in Pennsylvania. Therefore, even modest administrative cost savings would translate into more meaningful per-customer or per-MWh cost savings compared to the Company's larger peers in Pennsylvania.

Q. DO YOU AGREE WITH MR. ROULAND THAT THE COMPANY'S PROPOSAL ENTAILS ADDITIONAL BENEFITS COMPARED TO YOUR PROPOSAL?

A. No. The additional benefits claimed by Mr. Rouland are (i) likely lower supplier risk premiums; (ii) increased product diversity aimed at enticing more suppliers to bid; and (iii) a greater tranche size for FPFR products. First, Mr. Rouland does not provide any evidence that 12-month FPFR products, which UGI proposes to include as the largest share (approximately 76 percent) of the GSR-1 portfolio, are more liquid than 24-month FPFR products. In fact, the Company solicited both 12-month and 24-month FPFR products in the current DSP IV and they received the same number of bids for each since spring 2022 (i.e., in the last five solicitation cycles).[13] Neither does Mr. Rouland even claim, let alone demonstrate, that 24-month FPFR contracts entail significantly larger risk

[12] UGI Electric Statement No. 2-R, page 9, lines 1-9.
[13] UGI Electric's Response to OCA Interrogatory I-7, Attachment OCA-I-7.

supplier risk premiums compared to 12-month FPFR contracts. Unless the risk premium or illiquidity (lack of supplier participation) associated with 24-month FPFR contracts is significantly larger than the risk premium or illiquidity associated with 12-month FPFR contracts, 24-month FPFR contracts should be included in the residential default service supply product portfolio because of their rate stability benefits, as also acknowledged by Mr. Rouland.[14] Further, excluding a fixed MW-per-hour portion of the GSR-1 load from the FPFR contract and procuring that excluded portion as a separate energy block product does not reduce the overall risk of the portfolio, nor does it reduce the volumetric risk assumed by the FPFR suppliers. Since, by definition, the fixed-quantity energy block does not entail any volumetric risk, it merely forces the FPFR supplier to assume the entire volumetric risk and recover the associated risk premium and profit margin target from fewer MWh included in the FPFR contract. Therefore, UGI's proposed product portfolio does not reduce risk or risk premiums in this respect, either.

Second, Mr. Rouland does not substantiate his claim that diversifying the products would increase the number of entities bidding on UGI's FPFR solicitations. In fact, this claim (or hope) is demonstrably false because the entities that have been bidding on the Company's FPFR solicitations have not bid on the Company's block solicitations, and vice versa, in numerous solicitation cycles since October 2021.[15] FPFR contracts and block energy contracts are fundamentally different products in terms of content and risk profile, so it is unrealistic to expect an entity to bid on the FPFR solicitations just because the Company is also conducting a block solicitation.

Third, Mr. Rouland recognizes that my proposed 24-month FPFR contract is larger than UGI's proposed 12-month FPFR contract by total MWh in the contract.

[14] UGI Electric Statement No. 2-R, page 6, line 21 through page 7, line 5.
[15] UGI Electric's Responses to OCA Interrogatories I-5 and II-2, Attachment OCA-I-5 (Confidential) and Attachment OCA-II-2 (Confidential).

However, he posits that peak load contribution ("PLC"), rather than total MWh, should be the criterion by which to measure the size of a tranche because other Pennsylvania utilities do so. Mr. Rouland is conflating the issue of setting the number of tranches into which to divide the class load with setting the duration of the contract for a given tranche size and the attractiveness of the MWh volume of a tranche to a supplier. A supplier incurs certain fixed administrative expenses and burdens to participate in a utility's solicitation, prepare and submit bids, and execute its responsibilities under the contract as a load-serving entity in PJM Interconnection, LLC ("PJM"). The same supplier bids on the FPFR contracts on a $/MWh basis, so the larger the MWh volume of a tranche, the more attractive it is for a supplier. This is because the supplier can spread the fixed administrative expenses over a larger MWh volume while trying to keep its $/MWh bid as competitive as possible. I also note that there is large variation among Pennsylvania utilities in terms of the PLC per residential tranche. For example, PECO Energy Company had an average residential default service PLC of 3,200 MW between June 2023 and May 2024, and divided the same load into 62 tranches, resulting in an average of 51.6 MW of PLC per tranche.[16] Duquesne Light Company had an average residential (and lighting) default service PLC of 967 MW between June 2023 and May 2024, and divided the same load into 48 tranches, resulting in an average of 20.1 MW of PLC per tranche.[17] Therefore, the per-tranche PLC of residential FPFR contracts is not uniform, or even close, among Pennsylvania utilities as Mr. Rouland claims.

Finally, I note that Mr. Rouland suggests that no peer utility is equivalent to UGI in terms of default service plan or customer composition; therefore, direct comparisons cannot be made and only concepts can be gleaned from their plans.[18] However, Mr.

[16] https://www.pecoprocurement.com/index.cfm?s=dataRoom&p=monthly
[17] https://www.duquesnedsp.com/Documents/LoadandOtherData.aspx
[18] UGI Electric Statement No. 2-R, page 10, lines 15-17.

Rouland justifies measuring the size of an FPFR contract by PLC because he claims no other Pennsylvania utility measures it by MWh.[19] This appears to be an inconsistency in Mr. Rouland's approach to peer comparisons for UGI.

Q. DO YOU AGREE WITH MR. ROULAND THAT YOUR PROPOSAL SHOULD BE REJECTED BECAUSE IT FULLY RELIES UPON RELATIVELY ILLIQUID AND HIGH BID PREMIUM PRODUCTS THROUGH THE 100% USE OF A LONGER-TERM 24-MONTH FPFR CONTRACTS?

A. No. Mr. Rouland's argument is inconsistent, and therefore it should be dismissed. While Mr. Rouland criticizes my portfolio recommendation for relying exclusively on what he characterizes as relatively illiquid and high bid premium 24-month FPFR contracts, he supports the Company's proposal to procure 76 percent of the supplies through 12-month FPFR contracts. Further, Mr. Rouland acknowledges that he would consider 12-month FPFR contracts to be also relatively illiquid.[20] While Mr. Rouland asserts that 12-month FPFR contract is likely to include a lower premium than that of a 24-month or longer term FPFR product,[21] he neither demonstrates this using the FPFR bid analyses the Company already conducted, nor does he quantify the premium differential and assess whether the larger risk premium, if any, associated with the 24-month FPFR contract is worth its rate stability benefits. In light of these facts, Mr. Rouland's position is inconsistent because he is recommending the rejection of my proposed portfolio for consisting of what he claims to be relatively illiquid and high bid premium products, at the same time, he is supporting a portfolio more than three-quarters of which is also comprised of relatively illiquid and high bid premium products by his characterization.

[19] UGI Electric Statement No. 2-R, page 13, lines 16-19.
[20] UGI Electric's Response to OCA Interrogatory II-3(d).
[21] UGI Electric's Response to OCA Interrogatory II-4(g).

As I explained above, the Company's proposed portfolio does not reduce the overall risk premium by including some energy blocks because that merely forces the FPFR supplier to assume the entire volumetric risk and recover the associated risk premium and profit margin target from fewer MWh included in the FPFR contract. In summary, the same basis on which he recommends the rejection of my proposed portfolio would logically require the rejection of the portfolio proposed by the Company and supported by Mr. Rouland.

Q. MR. ROULAND POSITS THAT YOU STATED IN YOUR DIRECT TESTIMONY THAT UGI WILL BE ABLE TO EASILY PROCURE 24-MONTH CONTRACTS AND ASSERTS THAT HE DOES NOT NECESSARILY AGREE. PLEASE COMMENT.

A. I did not state that UGI will be able to procure 24-month FPFR contracts "easily." I provided three reasons why 24-month FPFR contracts are not too risky for wholesale suppliers. First, most Pennsylvania EDCs have been procuring them for their respective residential and small commercial default service portfolios successfully. Second, Mr. Rouland himself stated in his Direct Testimony that UGI successfully procured 24-month FPFR contracts during DSP IV and the pricing for such FPFR contracts continued to be within the range of market expectations. Finally, as Mr. Rouland himself explained in his Direct Testimony, the Company is proposing to make material changes to the FPFR products which would reduce FPFR suppliers' risk, including removing certain non-market-based costs from the wholesale suppliers' obligations and providing guidance and after-the-fact reconciliation on capacity pricing when PJM has not determined the final zonal capacity rate. These changes would make 24-month FPFR contracts less risky for wholesale suppliers in DSP V than they were in DSP IV. I concluded that because Mr. Rouland stated that UGI successfully procured 24-month FPFR contracts in DSP IV, and

that UGI is proposing changes to the FPFR contracts in DSP V which would make 24-month FPFR contracts less risky and more attractive for wholesale suppliers, there was no basis to believe that UGI would be unable to procure 24-month FPFR contracts in DSP V. I continue to believe that this is the most logical conclusion from these facts. It should also be noted that 24-month FPFR contracts received the same number of bids as 12-month FPFR contracts in UGI's last five solicitation cycles. Therefore, 24-month FPFR contracts appear to be as viable to procure for UGI as 12-month FPFR contracts, which the Company is proposing to include in its portfolio with a 76 percent share of the GSR-1 portfolio.

Q. DO YOU AGREE WITH MR. ROULAND THAT YOUR RECOMMENDED PORTFOLIO EXPOSES GSR-1 CUSTOMERS TO THE RISK OF A SINGLE PRODUCT?[22]

A. No. As described in Paragraph No. 76 of the Petition, the Company has a multi-layered contingency plan which includes products other than 24-month FPFR contracts. If the Commission agrees with my proposed portfolio, then the Company's contingency plan can be modified accordingly to include the procurement of a 12-month FPFR contract if the solicitation for a 24-month FPFR contract fails as the first layer, and the procurement of 12-month energy blocks as the second layer. Because the Company is proposing to conduct one auction (for delivery starting on June 1) between January and March, and another auction (for delivery starting on December 1) between July and September, each year, the Company will have sufficient time (between three months and five months) to execute multiple rounds of contingency planning. The adoption of my portfolio would enable UGI to first solicit the product (24-month FPFR) with the biggest rate stability benefit (among the alternatives which were proposed by a party in this proceeding) while

[22] UGI Electric Statement No. 2-R, page 12, lines 1-2.

also enabling the Company to procure other products if the solicitation for a 24-month FPFR contract fails.

Q. WOULD YOU SUPPORT A PORTFOLIO CONSISTING OF BOTH 24-MONTH AND 12-MONTH FPFR CONTRACTS?

A. Yes. I note that I recommended, and continue to recommend, a portfolio relying exclusively on 24-month FPFR contracts because of the Company's concern regarding dividing the load into too many tranches such that each tranche is too small to attract the interest of wholesale suppliers.[23] I would also support a portfolio consisting of both 24-month and 12-month FPFR contracts, if such a portfolio can be constructed without making the tranche size too small for supplier interest and participation. The Company estimates total GSR-1 PLC of approximately 138-140 MW,[24] so dividing the load into four tranches would result in a tranche size of 35 approximately MW, which is almost twice as large as Duquesne Light Company's residential (and lighting) default service load tranche size (20.1 MW). The Company can procure both 12-month and 24-month tranches if the GSR-1 load is divided into four tranches (as is done in the current DSP IV).

Q. PLEASE EXPLAIN WHY A PORTFOLIO CONSISTING OF A MIX OF 12-MONTH AND 24-MONTH FPFR CONTRACTS WOULD BE PREFERABLE TO THE PORTFOLIO PROPOSED BY THE COMPANY.

A. A portfolio consisting of a mix of 12-month and 24-month FPFR contracts would be preferable to the portfolio proposed by the Company for two reasons. First, procuring 24 percent of the GSR-1 default service product portfolio in the form of ATC blocks exposes 24 percent of the overall load to short-term changes in congestion costs between Western

[23] UGI Electric Statement No. 2, page 10, lines 5-10.
[24] UGI Electric Statement No. 2, page 10, lines 5-7.

Hub and UGI Zone (because UGI is proposing to buy ATC blocks for delivery at PJM Western Hub), and PJM ancillary services costs because the Company would not hedge these costs and pay spot market prices for them under the Company's proposed portfolio. If the Company procures all supplies in the form of FPFR contracts, then these costs (along with energy and AEC costs) are fixed for 12-month or 24-month periods. Therefore, a portfolio consisting exclusively of 12-month and 24-month FPFR contracts would deliver more stable rates than a portfolio which includes 24 percent in ATC blocks. Second, removing 20 MW (corresponding to 24 percent of total GSR-1 default service MWh) of the load from FPFR contracts shrinks the total MWh served by FPFR suppliers by 24 percent and makes FPFR contracts less attractive to wholesale suppliers. This appears to contradict the Company's goal of making the overall solicited load and each solicited tranche as large as possible to attract more FPFR suppliers.

Q. DID YOU CHANGE YOUR RECOMMENDATIONS ON THE GSR-1 DEFAULT SERVICE SUPPLY PORTFOLIO AFTER REVIEWING MR. ROULAND'S REBUTTAL TESTIMONY?

A. No. For the reasons I explained above, I continue to recommend that the residential and small commercial default service supply portfolio consist of 100 percent 24-month FPFR contracts, after a 12-month FPFR contract and an 18-month FPFR contract as "catch-up" procurements to start DSP V.

Q. IF THE COMMISSION WERE TO APPROVE UGI'S PROPOSED PORTFOLIO CONSISTING OF 12-MONTH FPFR CONTRACTS AND ENERGY BLOCKS, ARE YOU RECOMMENDING ANY CHANGES TO THE PROPOSED PROCUREMENT PLAN WHICH RELATE TO THAT SPECIFIC PRODUCT MIX?

A. Yes. I would recommend two modifications specific to that mix of products. First, I would recommend that UGI procure one 10-MW block with a five-year term and one 10-MW block with rolling 24-month terms. This configuration differs modestly from the Company's proposal, which is to procure both 10-MW blocks with rolling 24-month terms. The five-year block would enhance rate stability by fixing the price of energy for approximately 12 percent of the GSR-1 load for five years while also allowing UGI to satisfy the requirement of procuring long-term purchase contracts of more than 4 and not more than 20 years.[25] Other Pennsylvania utilities (e.g., PPL Electric Utilities Corporation) have successfully procured long-term purchase contracts in their respective default service plans.

Second, I would recommend that the Company's 50 percent load cap proposal applicable to FPFR contracts be rejected. While a load cap as an abstract concept may be a desirable feature of a default service plan due to its counterparty risk mitigation attributes, it is realistically viable only if the supplier participation in the FPFR solicitation process is consistently robust. In UGI's case, based on the numbers of bids the Company has been receiving in its FPFR solicitations in the last three years, implementing a load cap would come at the expense of materially reducing competition and/or even eliminating all potential offerors in certain auctions. Implementing a load cap at this point is likely to materially increase the awarded FPFR contract prices and/or

[25] Petition, Paragraph 8.

result in failed FPFR solicitations, which in turn increases the risk of exposing a large share of GSR-1 load to the volatile PJM spot market. If and when competition in UGI's FPFR solicitations reaches a robust level, such as the ones enjoyed by UGI's larger peers in Pennsylvania, a load cap could be a viable addition to the Company's default service plan.

Q. IN YOUR DIRECT TESTIMONY, YOU RECOMMENDED A 75 PERCENT LOAD CAP. IS THAT STILL YOUR RECOMMENDATION?

A. Yes. In my Direct Testimony I recommended a 75 percent load cap for the specific GSR-1 default service product portfolio which I recommended (i.e., 24-month FPFR contracts procured every six months for a quarter of the GSR-1 default service load). If the Commission adopts my recommended portfolio, I continue to recommend a 75 percent load cap associated with the procurement of that portfolio. My recommendation above that there should not be a load cap until UGI gets a robust level of competition in the FPFR solicitations is for the Company's proposed product mix and it is conditional on the Commission approving that specific mix of products.

III. PROCUREMENT STUDY

Q. PLEASE PROVIDE A BACKGROUD ON THE "PROCUREMENT STUDY" AND THE COMPANY'S PROPOSAL IN ITS PETITION ON THIS ISSUE.

A. As one of the conditions of UGI's DSP IV settlement, UGI agreed to file a study of the relative cost of default service supplies for GSR-1 residential and non-residential customers.[26] The Company commissioned the study (hereafter, the "Procurement Study") to the Northbridge Group and the resulting report is provided in UGI's DSP V filing.

[26] UGI Electric Exhibit JRT-2, Appendix A ("Procurement Study"), p.1.

The authors of the Procurement Study concluded that (1) residential GSR-1 customers would be between 8 percent and 9 percent more costly (on a $/MWh of load basis) to serve than non-residential GSR-1 customers;[27] and (2) conducting separate procurements for the residential and non-residential GSR-1 customer classes would increase UGI's annual administrative costs by $24,200.[28]

The authors of the Procurement Study did not make explicit recommendations based on their conclusions. They stated that "maintaining UGI's combined GSR-1 group may be the more prudent approach," and they outlined a cost allocation approach which the Commission could consider. That cost allocation approach is determining the Energy Cost ("EC") rate (in $/MWh), which is the projected direct and indirect purchased power costs incurred by UGI to acquire electric supply for the GSR-1 group, and then setting residential and non-residential GSR-1 EC rates two percent higher and seven percent lower, respectively, than this combined EC rate.

UGI proposed to conduct combined procurements for the entire GSR-1 group and apply the residential and non-residential rate allocation factors of 1.02 and 0.93, respectively, to the EC rate component in determining separate EC rates for residential and non-residential GSR-1 default service customers.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS REGARDING THE PROCUREMENT STUDY AND UGI'S PROPOSAL.

A. In my Direct Testimony, I made the following recommendations:

- The Commission should reject the arbitrary and ad hoc price premium which the Company is proposing to impose on residential default service customers to the detriment of residential and to the benefit of non-residential GSR-1 customers because there is no basis for implementing the proposed 10 percent rate differential between residential and non-residential GSR-1 customers.[29]

[27] Procurement Study, p. 2.
[28] Procurement Study, p. 17.
[29] OCA Statement No. 1, page 34, lines 7-12.

- Since combining the loads of residential and non-residential GSR-1 customers benefits both customer classes by making UGI's GSR-1 default service load volume larger and more attractive to FPFR suppliers, but there is no basis to implement a rate differential between the two customer classes, I recommend that UGI maintain the status quo; i.e., continue to conduct a joint procurement process for the two GSR-1 customer classes, and also continue to set a single GSR-1 EC rate and a single GSR-1 Price-to-Compare ("PTC") applicable to all (residential and non-residential) GSR-1 default service customers.[30]

I made these recommendations based on the following summary findings, which were fully explained and substantiated on pages 23-34 of my Direct Testimony:

- The methodology and assumptions of the Procurement Study are flawed in a way that accounts for the factors which would result in lower cost for non-residential GSR-1 customers (capacity, transmission) but neglects to account for the factors which would result in lower cost for residential customers (switching risk). Consequently, the Procurement Study biases the hypothetical cost of serving residential customers relative to the hypothetical cost of serving non-residential GSR-1 customers higher, Therefore, the residential and non-residential GSR-1 relative cost factors of 1.02 and 0.93, respectively, as reported in the Procurement Study, cannot be relied upon to arbitrarily increase (lower) the EC rate to residential (non-residential GSR-1) customers.[31]
- The approach taken in the Procurement Study is ill-suited for the FPFR approach because it ignores the risk associated with customer switching and shopping. Since UGI is not proposing any block-and-spot component in its DSP V GSR-1 default service supply portfolio, the Procurement Study's relative cost factor estimates cannot be relied upon to set a higher EC rate for residential customers than for GSR-1 non-residential customers.[32]
- The switching risk of UGI's small commercial customers is many times larger than the switching risk of UGI's residential customers. Since the Procurement Study ignored this switching risk and its effect on FPFR contract risk premiums for each respective customer class, the Procurement Study underestimated the risk premium for UGI's non-residential GSR-1 customers overestimated it for UGI's residential customers.[33]

[30] OCA Statement No. 1, page 34, lines 16-23.
[31] OCA Statement No. 1, page 34, lines 7-12.
[32] OCA Statement No. 1, page 29, lines 7-13.
[33] OCA Statement No. 1, page 31, line 24 through page 32, line 5.

Q. HOW DID OSBA WITNESS MR. EWEN RESPOND TO YOUR RECOMMENDATION?

A. Mr. Ewen disagreed with my critiques of the Procurement Study and with my recommendations, for four reasons. First, Mr. Ewen claims that my concerns about the calculation of "other costs," which include shopping or switching risk, are overstated because of the magnitudes of "other costs" as presented in the Procurement Study.[34] Second, Mr. Ewen posits that my analysis of differences between shopping and switching profiles of UGI's residential and small commercials customers is misleading because my analysis entails annual shopping percentages over an eight-year period while the FPFR suppliers are concerned only with one-year or two-year switching risk because those are the durations of the FPFR contracts on which they bid.[35] Third, Mr. Ewen criticizes me for not providing a $/MWh estimate of the switching or shopping risk premium.[36] Finally, Mr. Ewen states that my line of reasoning concerning the relative size of each customer class in GSR-1 would be relevant only if conducting separate procurements for residential and non-residential GSR-1 customers is necessary or reasonable.[37]

Q. HOW DID MR. TYAHLA RESPOND TO YOUR ANALYSES AND RECOMMENDATION?

A. UGI witness Mr. Tyahla acknowledges that the nature of certain procurement cost elements being quantified are ultimately subjective, observes that there are clear benefits to both residential and non-residential GSR-1 customers of combined procurement, and proposes the elimination of rate allocation factors. Mr. Tyahla's conclusion and ultimate recommendation on behalf of the Company would maintain the status quo; i.e., continuing to conduct a joint procurement process for the two GSR-1 customer classes,

[34] OSBA Statement No. 1-R, page 4, lines 15-19.
[35] OSBA Statement No. 1-R, page 5, lines 7-12.
[36] OSBA Statement No. 1-R, page 4, lines 12-15.
[37] OSBA Statement No. 1-R, page 6, lines 2-4.

and also continuing to set a single GSR-1 EC rate and a single GSR-1 PTC applicable to all (residential and non-residential) GSR-1 default service customers.[38]

Q. DO YOU CONCUR WITH MR. EWEN'S ASSERTION THAT YOUR CONCERNS REGARDING THE CALCULATION OF "OTHER COSTS," WHICH INCLUDE SHOPPING OR SWITCHING RISK, ARE OVERSTATED?

A. No. The Procurement Study's analysis period covered the period from 2017 through Spring 2022.[39] As UGI's Response to OCA Set II, #4 (Confidential) shows, **[BEGIN CONFIDENTIAL]** [redacted]

[38] UGI Electric Statement No. 1-R, page 7, line 4 through page 8, line 2.
[39] UGI Electric Statement No. 1-R, page 5, lines 9-11.

[redacted]

[redacted] **[END CONFIDENTIAL]**

Q. DO YOU CONCUR WITH MR. EWEN'S CLAIM THAT YOUR ANALYSIS OF DIFFERENCES BETWEEN SHOPPING AND SWITCHING PROFILES OF UGI'S RESIDENTIAL AND SMALL COMMERCIALS CUSTOMERS IS MISLEADING?

A. No. Mr. Ewen claims that my analysis of differences between shopping and switching profiles of UGI's residential and small commercials customers is misleading because my analysis entails annual shopping percentages over an eight-year period while the FPFR suppliers are concerned only with one-year or two-year switching risk because those are the durations of the FPFR contracts on which they bid.[40] I note that Mr. Ewen does not dispute the data which I present or my conclusion that the switching risk of UGI's small commercial customers is many times larger than the switching risk of UGI's residential customers. I disagree with Mr. Ewen that the standard deviation and relative standard deviation statistics which I presented are irrelevant. They measure the variability in shopping load percentage from one year to the next. Since the FPFR contracts are for either a one-year term or a two-year term, the variability of the shopping load percentage from one year to the next is the appropriate statistic by which to assess switching risk for FPFR suppliers.

[40] OSBA Statement No. 1-R, page 5, lines 7-12.

Q. HAVE YOU CONDUCTED A COMPARATIVE SHOPPING AND SWITCHING PROFILE ANALYSIS FOR RESIDENTIAL AND NON-RESIDENTIAL CUSTOMERS ON A MORE GRANULAR TIME SCALE AS SUGGESTED BY MR. EWEN?

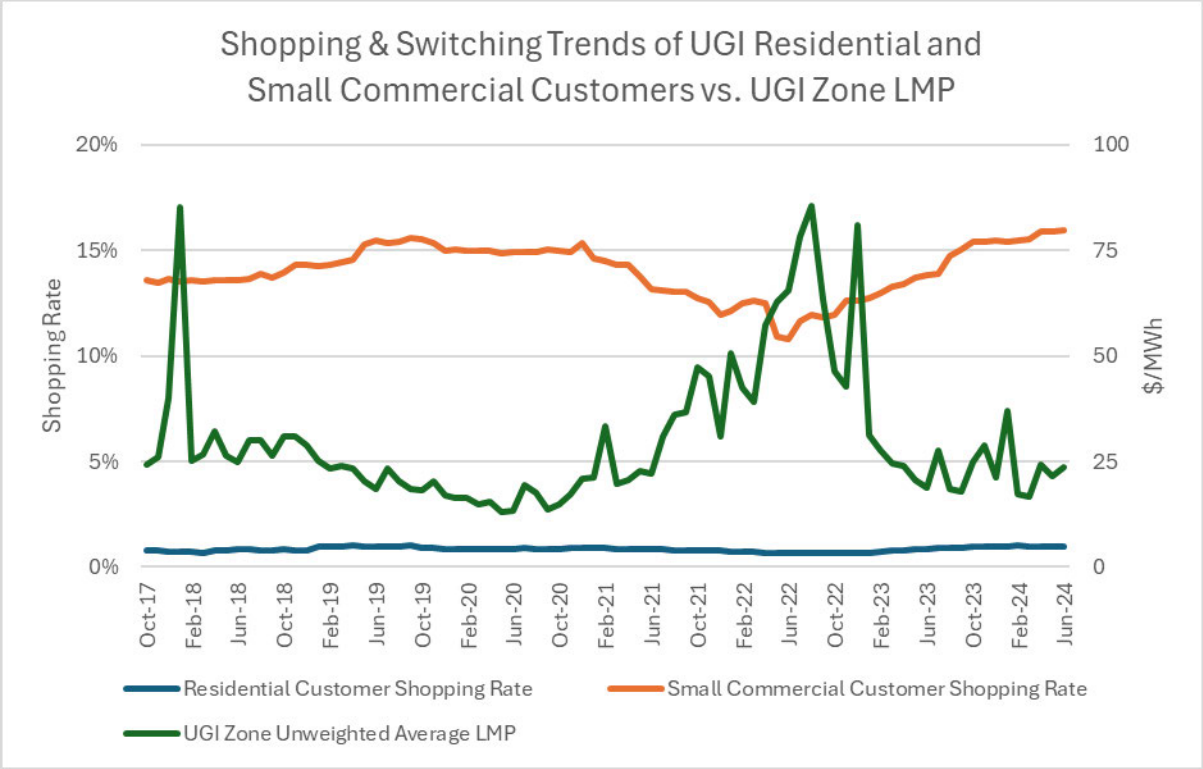
A. Yes. Figure 1 depicts the results of that analysis and confirms the conclusion of the analysis which was presented in my Direct Testimony as Table 2. I would like to highlight two observations from Figure 1. First, small commercial customers have both a higher shopping rate and a larger variability of that shopping rate even when measured within Mr. Ewen's preferred time intervals (such as one year and two years, which are the terms of the FPFR contracts procured by UGI in the current DSP IV). The shopping rate, as measured by the PLC of shopping customers to the PLC of all customers, of small commercial customers declined from 15.4 percent in December 2020 to 10.8 percent in June 2022 (down by 4.6 percentage points in 18 months) and increased to 15.5 percent in December 2023 (up by 4.7 percentage points in 18 months). The shopping rate of residential customers over the same period remained between 0.7 percent and 1.0 percent, negligible compared to the variability in the small commercial customer shopping rate.

Second, small commercial customers switch from electric generation supplier ("EGS") supply to default service when wholesale market prices rise (e.g., from end-2020 to mid-2022), and they switch from default service to EGS supply when wholesale market prices fall (e.g., from mid-2022 to end-2023). Therefore, small commercial customers are increasing FPFR suppliers' load when the cost of serving that load is rising (forcing FPFR suppliers to procure additional supplies at the now higher market rates) and they are reducing FPFR suppliers' load when the cost of serving that load is falling (forcing FPFR suppliers to liquidate some of their hedges at the now lower market rates). Given this correlation between load changes and wholesale market prices, FPFR

suppliers would include a risk premium to cover this potential risk, particularly during volatile market conditions such as the ones PJM market has been experiencing since 2021. I note that this volumetric risk, correlated with wholesale prices in a way that increases FPFR suppliers' risk of loss, is due almost exclusively to the shopping and switching behavior of small commercial customers since residential customer shopping remains at negligible levels between 0.7 percent and 1.0 percent under all market conditions.

The conclusion I reach from Figure 1 and the above observations is that Mr. Ewen's objection to my analysis is meritless and demonstrably false. UGI's small commercial customers impose major switching risk on the FPFR suppliers, which leads to higher risk premiums and higher PTCs, which is also incurred by residential customers even though their contribution to the shopping and switching risk and risk premiums is negligible.

Figure 1



Source: Revised Attachment OCA-I-14; S&P Global Capital IQ Pro. LMP: Locational Marginal Price.

Q. PLEASE RESPOND TO MR. EWEN'S CRITICISM THAT YOU DID NOT PROVIDE A $/MWH ESTIMATE OF THE SWITCHING OR SHOPPING RISK PREMIUM.

A. Providing that estimate is not incumbent on me or the OCA. Under the DSP IV settlement, it was the Company's responsibility to file a study of the relative cost of default service supplies for GSR-1 residential and non-residential customers. Since the relative cost of default service supplies for GSR-1 residential and non-residential customers also entails risk premium associated with switching and shopping risk, the study should have provided a sound and reliable estimate of switching or shopping risk to justify its rate allocation factor estimates. I demonstrated in my Direct, Rebuttal, and Surrebuttal Testimonies that the study filed by the Company did not provide a sound and

reliable estimate of switching or shopping risk, and therefore the rate allocation factors in the filed study were biased and unreliable. Since I demonstrated the bias in, and thus unreliability of, the rate allocation factors, it follows that the rate allocation factors in the filed study cannot be relied upon to arbitrarily increase (lower) the EC rate to residential (non-residential GSR-1) customers. The fact that I did not provide rate allocation factors, which was not incumbent upon me or on the OCA to do to begin with anyway, does not make the ones included in the filed study reliable. The fact is that because the rate allocation factors in the procurement study are demonstrated to be biased and unreliable, there is no basis for implementing the proposed 10 percent rate differential, or any rate differential, between residential and non-residential GSR-1 customers.

Q. PLEASE COMMENT ON MR. EWEN'S ASSERTION THAT YOUR LINE OF REASONING CONCERNING THE RELATIVE SIZE OF EACH CUSTOMER CLASS IN GSR-1 WOULD BE RELEVANT ONLY IF CONDUCTING SEPARATE PROCUREMENTS FOR RESIDENTIAL AND NON-RESIDENTIAL GSR-1 CUSTOMERS IS NECESSARY OR REASONABLE.

A. In my Direct Testimony, I demonstrated that, while combining the non-residential GSR-1 default service load with the residential default service load for procurement purposes benefits both customer classes in terms of making the volume attractive for FPFR suppliers, the non-residential GSR-1 class is clearly the larger beneficiary because, without the residential load, the non-residential GSR-1 default service load on a standalone basis would either attract no FPFR bidders or it would do so at a larger supplier embedded administrative cost. I noted that the larger administrative cost that would be embedded in FPFR supplier bids would be in addition to the larger switching risk-related risk premium which would be embedded in non-residential FPFR contract bids. If the standalone non-residential GSR-1 default service load does not receive any

(acceptable) FPFR contract bids, then non-residential GSR-1 default service customers would likely be forced into a spot market pricing or a block-and-spot arrangement, which would entail continuously incurring a large price risk and enduring volatile rates.[41]

Even though I did not recommend separate procurements or different rates for residential and non-residential GSR-1 default service customers as my first preference, I clearly stated that, if the Commission were inclined to approve separate EC rates and PTCs for the two customer classes to ensure that each customer class incurs its true procurement cost and risk, I would recommended that the Company conduct separate procurements for the two customer classes and determine the respective EC rate and PTC for each customer class based on the respective procurement costs of each customer class because it would be unfair, unduly discriminatory, and a cost shift to residential default service customers if non-residential GSR-1 default service customers were to pay an arbitrarily determined lower rate than residential default service customers even though, as I explained above, non-residential GSR-1 default service customers are the larger beneficiaries of the joint procurement process.[42]

In his rebuttal Testimony, Mr. Ewen misrepresents my recommendation for a joint procurement for the two classes. I did not recommend joint procurement under all circumstances. It is clearly stated in my Direct Testimony that I recommended joint procurement only if the rate allocation factors are eliminated and the status quo of charging the same EC rate and PTC to both customer classes is maintained. As I explained above, if rate allocation factors are determined based on "other costs" from more recent UGI FPFR auctions, the rate allocation factors can even dictate a lower rate for residential customers and a higher rate for small commercial customers. Therefore,

[41] OCA Statement No. 1, page 33, lines 10-22.
[42] OCA Statement No. 1, page 35, lines 5-16.

separate procurements are reasonable and may be necessary if the rate allocation factors are not eliminated.

Q. MR. ROULAND DISAGREES WITH YOUR PROPOSAL TO CONDUCT SEPARATE PROCUREMENTS FOR RESIDENTIAL AND NON-RESIDENTIAL GSR-1 CUSTOMERS IF THE RATE ALLOCATION FACTORS ARE NOT ELIMINATED.[43] PLEASE RESPOND.

A. Mr. Rouland disagrees with my proposal to conduct separate procurements for residential and non-residential GSR-1 customers if the rate allocation factors are not eliminated because he believes that conducting separate procurements would be detrimental to both residential and non-residential customers in the GSR-1 rate group. I would concur with that statement only if there are no rate allocation factors. As I explained above, if rate allocation factors are determined based on "other costs" from more recent UGI FPFR auctions, the rate allocation factors can result in a lower rate for residential customers and a higher rate for small commercial customers. Therefore, separate procurements would not necessarily lead to a detrimental result for residential customers if the rate allocation factors are not eliminated. There is no guarantee that the cost of residential customer-only FPFR contracts would be higher than the cost of FPFR contracts for the current GSR-1 group because the reduction in the supplier premium due to a reduction in switching risk (because, as demonstrated in Figure 1, small commercial customers pose a larger switching risk than residential customers do) may overwhelm the potentially modestly larger supplier administrative cost premium due to slightly smaller load of the residential class compared to the current GSR-1 group. Therefore, I disagree with Mr. Rouland and continue to recommend that, if the Commission were inclined to approve separate EC rates and PTCs for the two customer classes to ensure that each customer class incurs its

[43] UGI Electric Statement No. 2-R, page 16, lines 4-14.

true procurement cost and risk, the Company should conduct separate procurements for the two customer classes and determine the respective EC rate and PTC for each customer class based on the respective procurement costs of each customer class.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

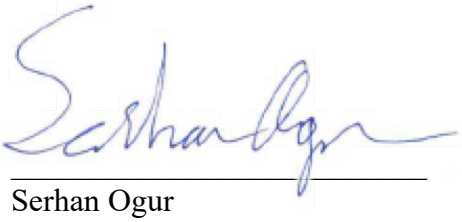
BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division For Approval of its Default Service Program for the Period from June 1, 2025, through May 31, 2029	:	Docket No. P-2024-3049343

VERIFICATION

I, Serhan Ogur, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 1SR, 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: September 25, 2024

Signature: 

Serhan Ogur

Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-2690

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	**Docket Nos. P-2024-3049343**
	:	**G-2024-3049351**
	:	
v.	:	
Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029 & Affiliated Interest Agreements of UGI Utilities, Inc	:	

ADMITTED TESTIMONY AND EXHIBITS
OF THE
OFFICE OF SMALL BUSINESS ADVOCATE

The Office of Small Business Advocate ("OSBA") admitted the enclosed testimony and exhibits as evidence into the evidentiary record at the Evidentiary Hearing on October 1, 2024, in the above-captioned proceedings:

- Direct Testimony of Mark D. Ewen, labelled OSBA Statement No. 1 with associated Exhibit IEc-1, with signed Verification by Mark D. Ewen.
- Rebuttal Testimony of Mark D. Ewen, labelled OSBA Statement No. 1-R, with signed Verification by Mark D. Ewen.
- Surrebuttal Testimony of Mark D. Ewen, labelled OSBA Statement No. 1-S, with signed Verification by Mark D. Ewen.

Date: October 2, 2024

COMMONWEALTH OF PENNSYLVANIA

August 2, 2024

The Honorable Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

The Honorable Alphonso Arnold III
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025, through May 31, 2029 / Docket Nos. P-2024-3049343, G-2024-3049351

Dear Presiding Judges:

Enclosed please find the Direct Testimony of Mark D. Ewen, labelled OSBA Statement No. 1 with associated Exhibit IEc-1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceedings.

Copies will be served on all known parties in these proceedings, as indicated on the attached Certificate of Service.

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 Chiavette (Cover Letter & Certificate of Service Only)
Mark D. Ewen
Parties of Record

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. (Electric Division) for Approval of its Default Service Program (DSP V) for the Period of June 1, 2025 Through May 31, 2029	:	**Docket No. P-2024-3049343**

Direct Testimony of

MARK D. EWEN

On Behalf of the

Pennsylvania Office of Small Business Advocate ("OSBA")

Date Served: August 2, 2024

Date Submitted for the Record: _____

DIRECT TESTIMONY OF MARK D. EWEN

1. Introduction

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

A. My name is Mark D. Ewen. I am a Principal and President of Industrial Economics, Incorporated ("IEc"), a consultancy of 165 professionals headquartered at 2067 Massachusetts Avenue, Cambridge, MA 02140. My consulting practice focuses on regulatory and environmental economics, expert case management and economic damages estimation in a variety of litigation contexts, and financial analysis. I obtained a B.A degree in Economics and Political Science from the University of North Dakota, and a Master of Public Policy degree from the University of Michigan. I have participated and provided testimony in a variety of proceedings before the Pennsylvania Public Utilities Commission ("the Commission"), including electric and gas base rates cases, 1307(f) purchased gas cost filings; energy efficiency and conservation cases, merger and acquisition cases, and default service plan ("DSP") petitions. My résumé and a listing of the expert testimony that I have filed in various litigation and utility regulatory proceedings are attached in Exhibit IEc-1.

Q. Please describe your assignment in this matter.

A. OSBA requested that I review the petition of UGI Utilities, Inc. Electric Division ("UGI Electric" or the "Company") for approval of its DSP for the period from June 1, 2025 through May 31, 2029 ("DSP V Petition"), to determine whether the proposal is consistent with sound economics and regulatory policy, and fairly treats small business customers.

Q. Please provide an overview of the salient features of the Company's proposed DSP V.

A. UGI Electric's proposed DSP V has much in common with DSP IV. Below, I list the key features of the plan.

- The Company proposes to retain two default service rate class groups, GSR-1 and GSR-2. GSR-1 includes residential and non-residential customers with maximum peak demand up to 100 kW. GSR-2 includes non-residential customers with maximum demand above 100 kW.

- The 100-kW demarcation would be determined on an annual basis, with the following analysis providing the initial customer classification in DSP V. Consistent with the Company's Settlement commitments in DSP IV, UGI Electric evaluated the classification of customers to the applicable GSR rate using each customer's highest billing demand in the 12-month period ending September 30, 2020. Any over/under collection, plus related interest, existing as of May 31, 2021, applicable to GSR-2 customers that migrated from rate GSR-1 was refunded/recovered from those customers directly over 12 billing periods beginning September 1, 2021. Under DSP IV, the initial customer classification would remain in effect for the duration of the DSP.

- The Company proposes to eliminate migration and reverse migration charges for customers transitioning from GSR-1 to GSR-2 and for customers transitioning from GSR-2 to GSR-1.

- Like in DSP IV, GSR-2 default service customers with load in excess of 100 kW will be supplied through hourly spot market purchases, supplemented by capacity, ancillary service, other transmission and AEPS credit purchases.[1]

- In DSP IV, default service purchases for the GSR-1 class are based 25 percent on a "block-and-spot" approach and 75 percent on a full-requirements load-following ("FRLF") approach. The Company represents that it experienced limited participation and higher risk premiums for its full requirements contracts over the past several years. In DSP V, the Company seeks to procure more supply for its GSR-1 customers through FRLF contracts. To reduce supplier risk, the Company proposes several modifications to its block and full requirements products, which I describe below. The Company also proposes to exclude the non-market transmission costs from its load-following contracts, which should have no impact on the PJM Interconnection LLC ("PJM") costs included in rates for GSR-2 customers.[2]

[1] "AEPS" credits refer to electricity supplier requirements under the Alternative Energy Portfolio Standards Act, primarily with respect to the purchase of Tier I, Tier II, and Solar alternative energy credits ("AECs") for specified percentages of the load served.

[2] Petition Statement No. 3, at 7.

- The block-and-spot approach under DSP IV involves the purchase of 6-month 7x24 and 5x16 energy block contracts twice per year based on forecast GSR-1 load, supplemented by Company procurement of the necessary capacity, transmission, ancillary services, and AEPs requirements. Energy variances between actual loads and block supplies are met by spot market purchases and sales. In the DSP V Petition, the Company proposes to implement a fixed MW around-the-clock block ("ATC") product to improve longer-term rate stability for GSR-1 customers and the marketability of full requirements products by creating a more stable and forecastable load. Once in steady-state, the base of the GSR-1 portfolio would consist of 20 MW of ATC block supply. The Company would procure laddered 10 MW ATC block contracts with 24-month terms annually. The 24-month block products will replace the existing 24-month FRLF product in DSP IV. This change would increase the FPFR tranche size to approximately 60 MW (from 40 MW in DSP IV), while increasing the total value proposal of the block product for block bidders.

- Under DSP IV, FRLF procurements were based on laddered 12-month or 24-month terms. In this proceeding, the Company proposes procurement of two tranches of 12-month FRLF contracts (eliminating the 24-month contracts), with each contract securing 50 percent of FRLF supply above the 20 MW ATC block purchases. The 12-month FRLF contracts would be staggered at 6-month intervals with the aim of providing rate stability for GSR-1 customers.

- To increase supplier participation and diversity in FRLF bids, the Company proposes to implement a FRLF tranche cap to limit the number of suppliers that can be awarded FRLF tranches to one supplier for a single 12-month tranche. By implementing a fixed MW ATC block product, FRLF suppliers will have pre-defined block terms throughout the course of the contract term. No limit would be placed on block supply. Thus, in theory, a single supplier may win one tranche of FRLF and all 20 MW of block supply.

- GSR-1 rates include a forecast cost component ("EC") and a reconciliation component ("ECA"). Under DSP IV, rates are reconciled on a quarterly basis. In this proceeding, UGI Electric proposes that rates be reconciled on a semi-annual basis, with a two-month lag. For example, the balance in the revenue-cost variance account as of March 31 will

be recovered in rates in the June 1 to November 30 period. However, if the variance would result in a more than 5 percent change on a total bill basis, the recovery period will be extended to 12 months.

- Currently, GSR-1 rates for residential and non-residential customers are the same on a per-kWh basis, and the Company does not issue separate procurements for residential and non-residential GSR-1 customers. Pursuant to the terms of UGI Electric's DSP IV Settlement, the Company hired a consultant to conduct a procurement study to evaluate the relative costs of default service supply to residential and non-residential customers.[3] The study concluded that the costs (measured in dollars per MWh) for residential GSR-1 customers are approximately 2% higher than the composite GSR-1 default service supply cost, and costs for non-residential customers are approximately 6-7% lower than the composite GSR-1 default service supply cost. The study also determined that separate procurements would increase cost-related risks and increase administrative costs. As a result, the Company proposes to continue combined residential/non-residential procurements, but it also proposes to utilize relative cost factors (based on the relative costs differential described above) to calculate separate default service rates for residential and non-residential GSR-1 customers, which would only apply to the EC component. To calculate the residential default service rate, the EC component will be multiplied by 1.02. A factor of 0.93 would be applied to the EC component to calculate the non-residential rate.

- Consistent with these default service rate modifications, the Company also proposes to calculate a separate price-to-compare ("PTC") for residential and non-residential customers served under GSR-1. The Company's tariff is updated to reflect separate PTC-1 rates. The PTC-1 is calculated as the GSR-1 rate plus the State Tax Adjustment Surcharge. UGI Electric maintains a separate PTC for GSR-2 customers ("PTC-2").

- UGI Electric is obligated to purchase excess supplies from its net metered customers as part of its default service portfolio. The Company expects a material increase in default

[3] The analysis, conducted by The NorthBridge group, is included as Exhibit JRT-2 in the Petition.

supply from these customers over the next three years, up to 186 kW in GSR-1 and up to 22 MW in GSR-2.

- Certain administrative costs are included in default service charges, forecast at $557,891 per year.[4] The major administrative cost items are the hiring of an Auction Manager ($150,000) for DSP V[5], load research costs ($126,000), and outside legal expenses ($62,500). Administrative costs are allocated between the two default service rate class groups based on either direct assignment or kWh load. In this proceeding, the Company plans to allocate 76 percent of costs to GSR-1 and 24 percent to GSR-2.

- Although the Company has a Standard Offer Program ("SOP") to which customers may be referred, no electric generation suppliers ("EGSs") currently participate in the program.

Q. Please describe the current state of shopping for smaller UGI Electric customers.

A. According to the Company, customer shopping levels for the GSR-1 rate schedule have fluctuated between five and seven percent. Data segregated by residential and non-residential GSR-1 customers are not available. Customer shopping levels for the GSR-2 rate schedule have been consistently higher and just below 50 percent. When shopping rates vary significantly over time, more risk is associated with longer-term procurements of electricity supply.

Q. What issues do you address in this testimony?

A. Section 2 addresses whether the Company's proposed procurement strategy for GSR-1 customers is reasonable. Section 3 addresses combined procurement for residential and non-residential customers below 100 kW and if the Company's proposed separate rates for the subgroups are reasonable. To the extent that I have not addressed an issue, it should not be concluded that I approve of the Company's proposal.

[4] Exhibit TAH-2.

[5] The Company will hire an Auction Manager whose role will subsume and expand on that of the existing market monitor. The Auction Manager would help improve the auction process and increase supplier participation. See Statement No. 1 at 7.

2. Procurement Approach for GSR-1

Q. Do you agree with the Company's proposed procurement strategy for GSR-1?

A. I continue to evaluate this issue. UGI Electric reports inconsistent supplier participation in DSP IV for both 12-month and 24-month FRLF contracts, in part due to variable block sizing which changed throughout the course of the contracts. Under DSP V, the Company proposes a series of modifications in an effort to improve supplier participation, competition, and diversity and to reduce contract premiums. In general, the Company seeks to secure more supply for its GSR-1 customers through FRLF contracts, a goal supported by the parties in the DSP IV Settlement. UGI Electric proposes to maintain block products, with a longer term of 24 months, ostensibly to reduce supplier risk and to increase supplier participation in the FRLF products. It is unclear if these changes will translate into lower premiums and more rate stability. However, given the Company's relatively small size and ongoing issues with supplier participation/competition, UGI Electric's procurement approach is not unreasonable in terms of balancing the goals of increasing the load procured from full-requirements contracts while keeping administrative costs and supplier risk at manageable levels. Implementing more abrupt modifications to the Company's existing procurement approach, for example eliminating the block products entirely, may not be feasible or prudent at this time.

3. Residential versus Non-Residential GSR-1 Rates

Q. Please provide the background to default service rates for smaller customers.

A. As a general rule, Pennsylvania electric distribution companies ("EDCs") serving as default service providers purchase default service supplies separately for their residential and small/medium non-residential customers. While there are certain administrative costs that apply to both customer groups, the rates for each group are effectively set based on the actual cost of providing service to that group. As such, the assignment of costs between classes is more precise than any arbitrary cost allocation method would produce.

However, because of the relatively small size of UGI Electric, it is generally believed that the cost for separate procurements would be material and outweigh the benefits of better cost assignment Thus, supplies for the combined group of residential and smaller non-

residential customers have been procured together, and the rates have been set on a per-MWh basis for all customers within the combined group.

The Settlement of the DSP IV proceeding (Docket No. P-2020-3019907) required the Company to file a study by June 30, 2022 evaluating the relative cost of default service supplies for GSR-1 residential and non-residential customers:

> *"The study will rely on data from DSP III, DSP IV, and actual data through at least the Fall of 2021. The study will evaluate the relative costs to GSR-1 residential and non-residential customers associated with: (1) both block-and-spot and full requirements procurements methods; and (2) both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement."*

The NorthBridge Group, a consulting firm, conducted the procurement study on behalf of UGI Electric.

Q. Did you review The NorthBridge Group's analysis?

A. Yes. Using a mix of historical data and price forecasts, the study identified the individual cost components associated with default service supply for UGI Electric's residential and non-residential GSR-1 customers under both block-and-spot and FRLF procurement methods. The cost components are Energy, Capacity, Network Integration Transmission Service, and Other Costs. The study found that the costs of UGI Electric's residential and non-residential GSR-1 default service supply are about 2 percent higher, and 6 to 7 percent lower, respectively, as compared to the composite GSR-1 default service supply cost.

The study also evaluated the relative merits, costs, and risks of combined versus separate default supply procurements for residential and non-residential GSR-1 customers. The consultants concluded there was insufficient data to quantify the different procurement strategies with a reasonable degree of confidence. As a result, the study illustrates the likely costs and complications if an EDC of UGI Electric's size were to implement separate default supply procurements. With separate procurements for residential and non-residential GSR-1 customers, the bids may be uncompetitive, or suppliers may not bid at all, given the smaller amounts of supply. UGI Electric's history of unsuccessful solicitations with relatively small supply provides supporting evidence for this hypothesis. The study also estimated default service supply amounts per solicitation for other Pennsylvania EDCs for separate residential and smaller non-residential groups. The Company's GSR-1 non-

residential customer group would have the smallest aggregate number of megawatt-hours of default service supply per solicitation for any single customer group among Pennsylvania EDCs. Finally, the study estimates that separate procurements for residential and non-residential groups would increase administrative costs by approximately $25,000 annually. The study concludes that maintaining UGI Electric's combined procurement strategy is the more prudent approach.

Q. Are the study's results reasonable?

A. I continue to evaluate this review and the study's supporting electronic workpapers. In terms of separate versus combined procurements for residential and non-residential GSR-1 customers, I find the study's methodology and conclusion to be reasonable. I support the approach of UGI Electric continuing its procurement strategy while assigning separate GSR-1 rates to residential and non-residential customers. However, I reserve the right to comment on the appropriate rate differential as I continue to evaluate the analysis of the relative costs of procuring default service supplies.

Q. Are the Company's proposed GSR-1 rate changes consistent with the results of the study?

A. Yes, the Company uses the cost differentials identified in the study to calculate separate default service rates for residential and non-residential GSR-1 customers. To calculate the residential default service rate, the EC component will be multiplied by 1.02. A factor of 0.93 would be applied to the EC component to calculate the non-residential rate.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

MARK D. EWEN

IEc

MARK D. EWEN **PRINCIPAL AND PRESIDENT**

Overview

Mr. Ewen has a strong background in applied economics, empirical methodologies, and financial analysis. As a Principal at Industrial Economics, Incorporated (IEc), he focuses on expert case management and economic damages estimation in a variety of litigation contexts, regulatory and environmental economics, and financial analysis. Within his areas of expertise, Mr. Ewen has been qualified as an expert witness before judicial and regulatory bodies (see schedule of testimony and appearances). He has also served as a Managing Director of the firm.

Education

Master of Public Policy, University of Michigan

Bachelor of Arts, summa cum laude in Economics and Political Science, University of North Dakota

Project Experience

Examples of his project work include the following:

Mr. Ewen has participated in various proceedings concerning energy markets and regulated utilities. These efforts, which focus on issues related to cost allocation and rate design, include working on behalf of industry and consumer intervenor groups in rate-making cases before the public utility commissions in Pennsylvania and Alberta, Canada, and the U.S. Postal Rate Commission. For example, for the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**, he has provided consulting and analytic support relating to electricity and natural gas tariff design, revenue requirements, and other regulatory initiatives concerning electrical and natural gas distribution utilities. For the **RHODE ISLAND ATTORNEY GENERAL,** Mr. Ewen conducted a due diligence review of PPL's proposed acquisition of Narragansett Electric Company and its potential impacts on the state's ratepayers.

For the **NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA) AND DEPARTMENT OF PUBLIC SERVICE (DPS)**, Mr. Ewen provided expert services assessing the economic impacts to municipal governments of extended electricity outages related to Tropical Storm Isaias. As part of this work, he constructed a model to estimate various costs of incremental staffing requirements for over 500 localities, including excess overtime, surge time (i.e., bringing on extra staff for outage response coordination and logistics), and idle time (e.g., crews waiting extended periods for downed lines to be de-energized). The review also included consideration of other direct costs, including, among others: effects to water systems; delivery of bottled water; operation of generators; and other constraints on the provision of essential governmental services. The litigation was settled to the satisfaction of the involved parties.

For the **NYSERDA AND NEW YORK DPS,** Mr. Ewen directed the development of a Generic Environmental Impact Statement (GEIS), pursuant to the requirement of the State Environmental Quality Review Act (SEQRA) that assessed the environmental and economic impacts of the "Reforming the Energy Vision" and "Clean Energy

Fund" initiatives within the state. He also directed the preparation of a Supplemental EIS to assess the environmental and economic impacts of the newly proposed Clean Energy Standard (CES). The CES is being developed to support the state's goal of supplying 50 percent of electricity demand with renewable generation resources by the year 2030. More recently, he directed the development of a model to assess the financial viability of various waste-to-energy technologies, and related social welfare benefits. This model uses detailed capital budgeting scenarios for specific facilities to generate forecast scenarios.

For the **U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF OCEAN ENERGY MANAGEMENT (BOEM)**, directing an assessment of the Bureau's approach to calculating and presenting the operating fee included in offshore wind leases under BOEM's jurisdiction. As part of this engagement, IEc provided a number of recommendations for simplifying the implementation of the operating fee formula and identified available data sources and approaches to estimating individual components of the fee formula. The review also addressed the structure and levels of fees associated with operations of renewable wind energy projects in the U.S. and worldwide. More recently, IEc has been supporting the development of Standard Operating Procedures for the fee calculation and lease management process. The overall goal is to provide information resources and a methodological approach that will allow lessees to derive accurate data for fee equation variables efficiently and consistently, and for BOEM to present the fee calculation clearly in the lease.

For **NYSERDA,** conducting a market analysis examining the potential economic development opportunities that could accrue in New York from hydrogen playing a role in achieving components of its Climate Leadership and Community Protection Act.

For the **U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF OCEAN ENERGY MANAGEMENT**, managed the development of a model to assess the economic and fiscal impacts of offshore oil and gas activity in the Gulf of Mexico and other BOEM OCS regions. This model, the Lifecycle Impacts Model (LCIM), assesses the economic and fiscal impacts associated with a specific lease or group of leases, over the time horizon of the lease(s). IEc's framework for the model was to build a capital budgeting forecasting tool for lease development, yielding estimates of industry expenditures, OCS revenues, industry profits, and employment impacts for a single lease or a set of leases. A key component of model development was to dynamically simulate the complex and unique timing parameters of lease development, incorporating the influence of critical exogenous factors like market prices and lease geology.

For the **U.S. COAST GUARD, NATIONAL POLLUTION FUNDS CENTER**, Mr. Ewen provides ongoing support to the NPFC in adjudicating damages claims resulting from oil spills. These claims include damages for business interruption, lost profits, property damage or value diminution, increased costs, and lost wages or employment, among other categories. Cases have also included damages for contract delays to construction projects and shipping demurrage. Industry sectors that Mr. Ewen has evaluated include: *electricity generation (nuclear and coal); railroads; cruise ships; oil ship transport; lodging and tourism; food and beverage; gambling; fisheries; marinas; real estate development, oil and gas development; and oil refining.*

Mr. Ewen's analytic work includes expert financial analysis and economic damages estimation in the context of general litigation and environmental enforcement actions. These efforts include assessing damages in breach of contract, nuisance, and cost recovery actions, and assessing the financial capabilities and economic benefit of noncompliance of firms accused of environmental violations. Clients in this area of his practice include the **U.S. DEPARTMENT OF JUSTICE**, **U.S. COAST GUARD**, **U.S. ENVIRONMENTAL PROTECTION AGENCY, STATES,** and private parties.

Testimony and Appearances

Mr. Ewen has provided testimony or appeared in the following cases and regulatory proceedings.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning the distribution system improvement charge (DSIC) case for PPL Electric Utilities Corporation (Docket No. R-2024-3048732, July 2024).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning cost allocation, revenue allocation, and rate design in the base rates case for First Energy of PA (Docket No. R-2024-30447068, June 2024).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning cost allocation, revenue allocation, and rate design in the base rates case for PECO Gas (Docket No. R-2024-3046932, June 2024).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning cost allocation, revenue allocation, and rate design in the base rates case for Columbia Gas of Pennsylvania (Docket No. R-2024-3046519, June 2024).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning the Default Service Plan for PPL Electric (Docket No. P-2024-3047290, June 2024).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning the Default Service Plan for PECO Energy Company (Docket No. P-2024-3046008, April/May 2024).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for National Fuel Gas Distribution Corporation (Docket No R-2024-3045177, March 2024).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning the Default Service Plan for Pike County Light and Power Company (Docket No. P-2023-3039927, July 2023).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning cost allocation, revenue allocation, and rate design in the base rates case for Columbia Gas of Pennsylvania (Docket No. R-2022-3031211, June 2022).

On behalf of Attorney General of the State of Rhode Island, submitted testimony before the Rhode Island Division of Public Utilities and Carriers concerning due diligence and related reviews of PPL Corporation's proposed acquisition of Narragansett Electric Company from National Grid USA (Docket No. D-21-09, November 2021).

Expert report and deposition testimony concerning economic damages and related financial matters, *Seaplane Adventures, LLC, vs. County of Marin, California*; expert report filed September 2021, deposition testimony given September 2021.

Expert reports and deposition testimony on bankruptcy reorganization plan feasibility and related financial matters, *in re: First Energy Solutions Corp., et al., Debtors, Case No. 18-50757*; expert reports filed July 2019, deposition testimony given August 9, 2019.

Expert declaration concerning economic damages and related financial matters, *in re: Outer Banks Power Outage Litigation, all actions, No. 4:17-CV-141-D*, March 2018.

Expert report and deposition testimony on Economic Damages in *State of Alaska v. Williams Alaska Petroleum, Inc., et al*., *Case No. 4FA-14-01544 CI;* expert report filed December 2016, deposition testimony given February 15, 2017.

Expert reports and deposition testimony on Economic Benefit in *Sierra Club v. Energy Future Holdings Corp. et al.*, *Case No. 5:10-cv-156 (E.D. Tex.)* and *Sierra Club v. Energy Future Holdings Corp. et al.*, *Case No. 6:12-cv-108 (W.D. Tex.)*; expert reports filed in June and July 2013, deposition testimony given August 2013. Trial testimony given in Case No. *6:12-cv-108 (W.D. Tex.) in March 2014*.

Expert testimony on ability-to-pay provided, in the matter of Mercury Vapor Processing Technologies, Inc., et al. (No. RCRA-05-2010-0015), July 2011.

Expert Declaration in a patent case concerning economic and financial matters in the context of environmental credits valuation -- In re Patent Application of: Jeff Andrilenas et al., Application No.: 12/328,219, For: VALUING ENVIRONMENTAL CREDITS, submitted June 2011.

Export report and deposition testimony on financial matters in Evansville Greenway and Remediation Trust v. Southern Indiana Gas and Electric Company, Inc., et al. (03:07-cv-0066-SEB-WGH); expert report filed July 2009, deposition testimony given January 2010.

Expert testimony on ability-to-pay provided, in the matter of Robert J. Heser, Andrew J. Heser, and Heser Farms (No. CWA-05-2006-0002), May 2007.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning tariff design issues for Columbia Gas of Pennsylvania (Docket No. R-00049783, May 2005).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning cost allocation, revenue assignment, and rate design for Pennsylvania Power and Light (Docket No. R-00049255, August 2004).

Expert report on economic damages in United States v. Southern California Edison No. CIV. F-01-5167 OWW DLB (E.D. Cal)., July 2004; deposition testimony provided September 2004.

Expert testimony on ability-to-pay provided in U.S. v. Peter Thorson, Managed Investments, Inc., Construction Management, Inc., and Gerke Excavating, Inc. (No. 03-C-0074), May 2004.

Expert testimony on ability-to-pay provided in U.S. v. Paul A. Heinrich and Charles Vogel Enterprises, Inc. (No. 03-C-0075-S), October 2003.

Expert testimony on ability-to-pay provided in the matter of Dearborn Refining Company (No. RCRA-05-2001-0019), February 2003.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for PFG Gas and Northern Penn Gas (Docket No. R-00027389, July 2002).

Expert report and testimony on economic damages in Carol Marmo et al. v. IBP, Inc.; expert report filed March 2002, deposition testimony given June 2002, September 2004, and testimony at trial given February 2005.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for National Fuel Gas Distribution Corporation (Docket No. R-00016789, March 2002).

On behalf of the Office of the Consumer Advocate, providing testimony before the United States Postal Rate Commission regarding cost allocation of city carrier street time costs. Docket No. R2000-1, July 11, 2000.

Expert report and declaration on ability-to-pay in re Indspec Chemical Corporation and Associated Thermal Services, Inc., and related testimony in U.S. EPA administrative court on February 24, 1998 (No. CAA-III-086).

Expert report on ability-to-pay in re Harrisburg Hospital and First Capital Insulation, Inc. and related testimony in U.S. EPA administrative court on October 8, 1997 (No. CAA-III-076).

2024

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. (Electric Division) for Approval of its Default Service Program (DSP V) for the Period of June 1, 2025 Through May 31, 2029	:	**Docket No. P-2024-3049343**

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Direct Testimony labelled OSBA Statement No. 1 with associated Exhibit IEc-1 is 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 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: 8/1/2024

Mark Ewen

Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket Nos. P-2024-3049343**
	:	**G-2024-3049351**
Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029	:	

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 Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
debuckley@pa.gov

The Honorable Alphonso Arnold III
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
alphonarno@pa.gov

Allison Kaster, Esquire
Director
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
akaster@pa.gov

Lindsay Berkstresser, Esquire
Counsel, Energy & Regulatory
UGI Corporation
500 North Gulph Road
King of Prussia, PA 19406
Berkstresserl@ugicorp.com

Harrison W. Breitman, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
HBreitman@paoca.org

Anthony D. Kanagy, Esquire
Nicholas A. Stobbe, Esquire
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101-1601
akanagy@postschell.com
nstobbe@postschell.com

Devin T. Ryan, Esquire
Post & Schell, P.C.
One Oxford Centre
301 Grant Street, Suite 3010
Pittsburgh, PA 15219
dryan@postschell.com

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak, LLC
100 N 10th Street
Harrisburg, PA 17101
tsstewart@hmslegal.com

DATE: August 2, 2024

/s/ Steven C. Gray

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

COMMONWEALTH OF PENNSYLVANIA

August 30, 2024

The Honorable Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

The Honorable Alphonso Arnold III
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025, through May 31, 2029 / Docket Nos. P-2024-3049343, G-2024-3049351

Dear Presiding Judges:

Enclosed please find the Rebuttal Testimony of Mark D. Ewen, labelled OSBA Statement No. 1-R, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceedings.

Copies will be served on all known parties in these proceedings, as indicated on the attached Certificate of Service.

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 Chiavette (Cover Letter & Certificate of Service Only)
Mark D. Ewen
Parties of Record

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. (Electric Division) for Approval of its Default Service Program (DSP V) for the Period of June 1, 2025 Through May 31, 2029	:	**Docket No. P-2024-3049343**

Rebuttal Testimony of

MARK D. EWEN

On Behalf of the

Pennsylvania Office of Small Business Advocate ("OSBA")

Date Served: August 30, 2024

Date Submitted for the Record: _____

REBUTTAL TESTIMONY OF MARK D. EWEN

1. Introduction

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

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

Q. What is the purpose of this rebuttal testimony?

A. This rebuttal testimony responds to the direct testimony of Pennsylvania Office of Consumer Advocate ("OCA") witness Serhan Ogur. I cover issues related to the Procurement Study that UGI Utilities, Inc. Electric Division ("UGI Electric" or the "Company") commissioned and included as part of its petition for approval of its DSP for the period from June 1, 2025 through May 31, 2029 ("DSP V Petition").

2. Residential versus Non-Residential GSR-1 Rates

Q. Please summarize the purpose and results of the Procurement Study.

A. UGI Electric's supplies default service to residential and small/medium non-residential customers (up to 100 kW in peak load) under a fixed per-kWh Rate GSR-1, and larger non-residential customers (over 100 kW) under hourly priced Rate GSR-2. Rate GSR-1 is currently updated quarterly, and it consists of a current energy cost ("EC") rate and a reconciliation rate (inclusive of interest).

As a general rule, Pennsylvania electric distribution companies ("EDCs") serving as default service providers purchase default service supplies separately for their residential and small/medium non-residential customers. However, because of the relatively small size of UGI Electric, the cost for separate procurements would be material and outweigh the benefits of better cost assignment. Thus, UGI Electric has procured supplies for the combined group of residential GSR-1 customers and non-residential GSR-1 customers together, and the rates have been set on a per-MWh basis for all customers within the combined GSR-1 group.

The Settlement of the DSP IV proceeding (Docket No. P-2020-3019907) required the Company to file a study by June 30, 2022 evaluating the relative cost of default service supplies for GSR-1 residential and non-residential customers:

> *"The study will rely on data from DSP III, DSP IV, and actual data through at least the Fall of 2021. The study will evaluate the relative costs to GSR-1 residential and non-residential customers associated with: (1) both block-and-spot and full requirements procurements methods; and (2) both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement."*

The NorthBridge Group conducted the Procurement Study for UGI Electric. Using a mix of historical data and price forecasts, the Procurement Study identified the individual cost components associated with default service supply for UGI Electric's residential and non-residential GSR-1 customers under both block-and-spot and full-requirements load-following ("FRLF") procurement methods. The cost components are energy, capacity, Network Integration Transmission Service ("NITS"), and "other costs". Energy, capacity and NITS costs are derived from PJM market data. To derive "other" costs for UGI Electric, NorthBridge Group relies on auction price data for PECO Energy Company ("PECO"). The Procurement Study found that the total costs of UGI Electric's residential and non-residential GSR-1 default service supply are about 2 percent higher, and 6 to 7 percent lower, respectively, as compared to the composite GSR-1 default service supply cost.

Q. Are the Company's proposed GSR-1 rate changes consistent with the results of the Procurement Study?

A. Yes, the Company uses the cost differentials identified in the study to calculate separate default service rates for residential and non-residential GSR-1 customers. To calculate the residential default service rate, the EC rate will be multiplied by 1.02. A factor of 0.93 would be applied to the EC component to calculate the non-residential rate. The Company proposes to continue combined residential/non-residential procurements for GSR-1.

Q. Please summarize Witness Ogur's critique of the Procurement Study.

A. Overall, Witness Ogur concludes that the findings of the Procurement Study are invalid and should not be relied upon to set different EC rates for residential and non-residential GSR-1 customers. According to OCA Statement 1 at page 25: "The methodology and

assumptions of the Procurement Study are flawed in a way that accounts for the factors which would result in lower cost for non-residential GSR-1 customers but neglects to account for the factors which would result in lower cost for residential customers." Witness Ogur cites two main issues with the Procurement Study.

First, Witness Ogur claims that the Procurement Study did not directly and explicitly account for the differences in switching or shopping risk between residential and non-residential GSR-1 customers. Electric generation suppliers ("EGSs") will demand a higher risk premium from customers with a higher propensity to shop or switch suppliers. Witness Ogur objects to the Procurement Study's methodology for calculating the "other costs" of providing default service to residential and non-residential customers; this category includes costs that results from supply risk.

Second, Witness Ogur argues that the Procurement Study did not incorporate the size of the load or the size of the tranche of each individual class load if UGI Electric were to procure supplies for residential and non-residential GSR-1 default service customers separately.

I address these points in detail below.

Q. Are Witness Ogur's concerns about the Procurement Study's treatment of "other costs" reasonable?

A. As noted above, the "other costs" category consists of a number of relatively small cost items that cannot be directly derived for UGI Electric, including a risk premium associated with a variety of risks incurred by default service suppliers. These risks include volume risk, switching risk, transmission cost risks, and unhedged price risks. Witness Ogur is correct that, as a matter of finance theory, higher shopping risk should result in a demand for a higher risk premium from suppliers. Because none of the "other costs" can be measured directly, it is necessary to use a reasonable proxy for those costs.

In the Procurement Study, "other costs" are calculated as the difference between the FRLF auction price (in $/MWh) and estimates of energy, capacity, and transmission costs for PECO's FRLF auctions conducted separately for residential and small commercial customers between 2017 and 2022. Witness Ogur argues that the "other costs" category is overly broad, as they include the costs of ancillary services, customers credits associated

with congestion rents, various PJM services, Alternative Energy Credits ("AEC"), and costs that result from the risks associated with default service supply.

In the Procurement Study, "other costs" are $5.98/MWh, or 7.0 percent of total calculated default service costs of $84.92/MWh for UGI's composite GSR-1 class (for the June 2024 – May 2025 auction period). Note that the value for "other costs" includes costs that are not part of the risk premium, and that the risk premium itself reflects certain risks that are common to both residential and non-residential customers.

Segregated by customer type, "other costs" are $5.78/MWh (between 4-7 percent of total costs) for residential GSR-1 customers and $6.63/MWh (between 5-8 percent of total costs) for non-residential GSR-1 customers, based on the three studied auction periods.[1] "Other costs" are 15 percent *higher* for non-residential customers than for residential customers, according to the Procurement Study. Witness Ogur does not provide a dollar per MWh estimate of the switching or shopping risk premium that would have a material impact on the Procurement Study's findings that residential customers are materially more costly to serve. Given the relatively minor contribution of "other costs" to total default service costs and the many costs unrelated to risk premiums that are included under "other costs", Witness Ogur's concerns about the calculation of "other costs" are thus over-stated in terms of the impact that shopping or switching risk has on the relative costs of service for UGI Electric's residential and non-residential customers.

Q. Witness Ogur analyzes the differences between shopping and switching profiles of UGI Electric's residential and small commercial customers. Does this analysis invalidate the methodology in the Procurement Study in relation to the estimation of the "other costs" differential or ratio between UGI Electric's residential and non-residential GSR-1 customers?

A. No, it does not. Witness Ogur's analysis is misleading and omits key factors that influence default service volumes and supplier risk. OCA Statement 1, Table 2 reports the percentage of total generation sales to residential and small commercial retail customers of UGI Electric

[1] Study of the Relative Cost of Default Service Supply for Residential and Non-Residential GSR-1 Customers dated June 24, 2022, page 14. The three auction periods are June 2022 – May 2023, June 2023 – May 2024, and June 2024 – May 2025.

and PECO made by EGSs from 2015 through 2022 on an annual basis. The table includes the 8-year standard deviation, average, and relative standard deviation (ratio of standard deviation to average) for each customer class. Witness Ogur concludes from these statistics that UGI Electric's non-residential GSR-1 customers have higher shopping rates than residential GSR-1 customers, and that the former has a higher switching rate (as measured by the relative standard deviation of 23 percent).

The comparison of volatility (standard deviation and relative standard deviation) over an 8-year period would be relevant if the analysis was intended to evaluate contracts with an 8-year procurement term. However, the only volatility with which an EGS is concerned is that which occurs within the procurement periods, namely from the bid date to the end of the contract. In this case, the relevant timeframe would be within each of the Company's proposed laddered 12-month and 24-month procurement periods.

Further, it is not shopping volumes alone that matter for this analysis, but the effect of shopping changes on the volumes for default service customers. For example, if customers with lower load factors are more likely to shop, then one would expect volumetric shopping rates to go up in peak seasons and down in off-peak seasons, even if there is no change in the number of customers who shop. Looking simply at the volatility in annual shopping rates over the entire period does not provide useful information.

Q. Moving on to Witness Ogur's argument that the relatively small size of the non-residential GSR-1 tranche implies larger administrative costs for this group compared to residential customers. Is this argument reasonable?

A. Since non-residential GSR-1 customers account for 27 percent of the total GSR-1 default service load, Witness Ogur argues that "the non-residential GSR-1 default service load on a standalone basis would either attract no FPFR bidders or it would do so at a larger supplier embedded administrative cost."

Witness Ogur acknowledges that combining the residential and non-residential GSR-1 default service loads for procurement purposes benefits both groups and recommends that the Company continue this practice. However, Witness Ogur also argues that the non-residential customer group is "clearly the larger beneficiary" since the Company would

purportedly pay more in administrative cost and risk premiums if it procured supply for this customer group alone. This line of reasoning would only be relevant if the objective of this exercise was only to evaluate whether conducting separate procurements for residential and non-residential GSR-1 customers is necessary or reasonable. There is broad agreement among the parties (including OCA), with supporting evidence provided in the Procurement Study, that such a strategy is not necessary or reasonable. The relevant determination is thus how costs should be reasonably allocated *given that* combined procurement is necessary for a utility of UGI Electric's size.

Q. Please summarize your conclusions and recommendations regarding UGI Electric's proposed EC rates for residential and non-residential GSR-1 customers.

A. I conclude that, because the Procurement Study's methodology and assumptions are sound, the Company's proposed rates for residential and non-residential GSR-1 customers are reasonable and consistent with the findings of the Procurement Study. Witness Ogur does not provide sufficient evidence that challenges or invalidates the results of the Procurement Study. I recommend that the Commission approve the Company's proposed rate structure for the GSR-1 class.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. (Electric Division) for Approval of its Default Service Program (DSP V) for the Period of June 1, 2025 Through May 31, 2029	:	**Docket No. P-2024-3049343**

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Rebuttal Testimony labelled OSBA Statement No. 1-R 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: 8/29/2024

Mark Ewen

Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	**Docket Nos. P-2024-3049343**
	:	**G-2024-3049351**
v.	:	
	:	
Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029	:	

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 Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
debuckley@pa.gov

The Honorable Alphonso Arnold III
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
alphonarno@pa.gov

Allison Kaster, Esquire
Director
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
akaster@pa.gov

Lindsay Berkstresser, Esquire
Counsel, Energy & Regulatory
UGI Corporation
500 North Gulph Road
King of Prussia, PA 19406
Berkstresserl@ugicorp.com

Harrison W. Breitman, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
HBreitman@paoca.org

Anthony D. Kanagy, Esquire
Nicholas A. Stobbe, Esquire
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101-1601
akanagy@postschell.com
nstobbe@postschell.com

Devin T. Ryan, Esquire
Post & Schell, P.C.
One Oxford Centre
301 Grant Street, Suite 3010
Pittsburgh, PA 15219
dryan@postschell.com

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak, LLC
501 Corporate Circle, Suite 302
Harrisburg, PA 17110
tsstewart@hmslegal.com

DATE: August 30, 2024

/s/ Steven C. Gray

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

COMMONWEALTH OF PENNSYLVANIA

September 25, 2024

The Honorable Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

The Honorable Alphonso Arnold III
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025, through May 31, 2029 & Affiliated Interest Agreements of UGI Utilities, Inc. / Docket Nos. P-2024-3049343 & G-2024-3049351

Dear Presiding Judges:

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

Copies will be served on all known parties in these proceedings, as indicated on the attached Certificate of Service.

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 Chiavette (Cover Letter & Certificate of Service)
Mark D. Ewen
Parties of Record

OSBA Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	**Docket Nos. P-2024-3049343**
	:	**G-2024-3049351**
	:	
v.	**:**	
Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029 & Affiliated Interest Agreements of UGI Utilities, Inc	**:**	

Surrebuttal Testimony

of

MARK D. EWEN

On Behalf of the

Pennsylvania Office of Small Business Advocate ("OSBA")

Date Served: September 25, 2024

Date Submitted for the Record: _____

1. Introduction

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

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

Q. What is the purpose of this surrebuttal testimony?

A. This surrebuttal testimony responds to the rebuttal testimony of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") witnesses Jesse Tyahla, James Rouland, and Tracy Hazenstab. I organize this testimony as follows:

First, I address the Procurement Study that forms the basis for the rate allocation factors that the Company proposed for application to residential and non-residential GSR-1 customers. The Company commissioned and included the Procurement Study in its petition for approval of its DSP for the period from June 1, 2025, through May 31, 2029 ("DSP V Petition"). In rebuttal, Witness Tyahla and Witness Rouland responded to my direct testimony and that of Pennsylvania Office of Consumer Advocate ("OCA") witness Serhan Ogur.

Second, I support the Company's ongoing defense of its proposal to classify GSR-1 and GSR-2 customers based upon their supply peak load impact, while offering certain points of clarification.

2. Residential versus Non-Residential GSR-1 Rates

Q. Between the DSP V Petition and rebuttal, has the Company changed its position regarding the application of separate rates for residential and non-residential GSR-1 customers?

A. Yes, it has. Consistent with the results of NorthBridge Group's Procurement Study, the Company proposed in the DSP V Petition to calculate separate default service rates for residential and non-residential GSR-1 customers (up to 100 kW in peak load). To calculate the residential default service rate, the current energy cost ("EC") rate will be multiplied by 1.02. A factor of 0.93 would be applied to the EC component to calculate the non-residential rate. The Company proposed to continue combined residential/non-residential procurements for GSR-1.

However, the Company withdrew this proposal in Witness Tyahla's rebuttal testimony and proposed to maintain the status quo of combined procurements while not implementing separate rate allocation factors for residential and non-residential GSR-1 customers.

Q. What reasons does the Company offer for withdrawing its proposal to apply separate residential and non-residential GSR-1 procurement factors to set rates?

A. The Company's decision appears to be based largely on general expediency. Although Witness Tyahla defends the Procurement Study and rebuts OCA Witness Ogur's arguments thereof, Witness Tyahla represents that maintaining the status quo of combined procurements and rates "would be less administratively burdensome" and represent "a reasonable balance of all interests."

Witness Tyahla offers similar critiques of Witness Ogur's direct testimony as I did in my rebuttal testimony. Namely, Witness Tyahla: a) defends the Procurement Study's estimation of the differences in the "other costs" of procuring default supply for residential and non-residential customers; and b) notes that Witness Ogur does not any offer any alternative calculation or estimate of the rate allocation factors for the residential and non-residential customer groups.

Q. Please summarize your conclusions and recommendations regarding UGI Electric's proposed EC rates for residential and non-residential GSR-1 customers.

A. I maintain that because the Procurement Study's methodology and assumptions are sound, the Company's proposed rates in the DSP V Petition for residential and non-residential GSR-1 customers are reasonable and consistent with the findings of the Procurement Study. I recommend that the Commission approve the Company's proposed rate structure for the GSR-1 class. I explained the basis of my recommendation in detail in my rebuttal testimony.

I thus object to the Company withdrawing its original proposal and to Witness Tyahla's characterization that maintaining the status quo of default service procurements is "a reasonable balance of all interests." Maintaining the status quo is unfair to small business customers and inconsistent with cost causation principles for ratemaking in Pennsylvania. The Company supported the methodology and findings of the Procurement Study in its DSP V Petition and in rebuttal. The Settlement of the DSP IV proceeding (Docket No. P-2020-3019907) required the Company to file a study evaluating the relative cost of default

service supplies for GSR-1 residential and non-residential customers. The Company complied with this requirement, developed a reasonable proposal to apply separate EC rates for residential and non-residential customers based on the results of the Procurement Study, but now inexplicably wishes to withdraw the proposal. UGI Electric determined that procuring supply is costlier for residential customers than for non-residential customers in GSR-1. Further, in the DSP V Petition the Company represented that implementing the separate rate structure for the two customer groups was feasible and not overly burdensome. The Company should stand by its original proposal based on the findings of the Procurement Study.

3. Classification of Large Customer-Generators in GSR-2

Q. Please summarize UGI Electric's proposal to classify GSR-1 and GSR-2 customers based upon their supply peak load impact.

A. The Company outlined its proposal in the DSP V Petition. Where a customer's (including a net metering customer's) supply peak load impact is less than 100 kW, that customer will be included in GSR-1. Where a customer's (including a net metering customer's) supply peak load impact is greater than or equal to 100 kW, that customer will be included in GSR-2. GSR-2 customers will be placed on a mandatory variable rate that will not include the same cost recovery as GSR-1.

Q. Please summarize Penn Renewables Witness Crist's position on classifying customers based on their peak supply.

A. Witness Crist generally objects to large customer-generators being classified as GSR-2 customers and argues that it is unreasonable to classify customers based on their peak supply.

Q. Please state OSBA's position on UGI Electric's proposal to classify GSR-1 and GSR-2 customers based upon their supply peak load impact.

A. OSBA supports the Company's proposal and agrees with the points laid out in the rebuttal testimonies of Witness Rouland and Witness Hazenstab.

Q. Do you have any concerns with the Company's proposal?

A. I do have one point that may require the Company's confirmation or clarification. In rebuttal testimony (page 15), Witness Hazenstab states that, if the Commission deems it

necessary in order to approve the classification scheme for GSR-1 and GSR-2 customers, UGI Electric requests a waiver of the 25 kW peak load threshold in order for large customer generators to be classified as GSR-2 default service customers for the reasons set forth by the Company in this proceeding." Counsel has expressed concern that a waiver of the protections for customers with less than 25 kW registered peak load (52 Pa Code section 54.187(h) could allow the Company to place small business customers in GSR-1 on a variable rate at the Company's discretion.

My reading is that the Company cannot move a small business customer in GSR-1 into GSR-2 at its discretion because the customer would not meet the tariff criteria. According to the Company's filed Tariff (DSP V Petition, Appendix A, page no. 39), GSR-2 shall apply to all non-residential customers if either the net load or the net supply exceeds 100 kW. I suspect that Witness Hazenstab is requesting this waiver because there may be customer-generators with large net supply loads but still with less than 25 kW of consumption load. I respectfully request confirmation from UGI Electric that the waiver Witness Hazenstab proposes would not give the Company license to move non-residential GSR-1 customers into the GSR-2 class unless such customers qualify for the latter according to the Company's filed Tariff.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	**Docket No. P-2024-3049343**
v.	:	G-2024-3049351
Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029 & Affiliated Interest Agreements of UGI Utilities, Inc	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Surrebuttal Testimony labelled OSBA Statement No. 1-S 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: 9.24.2024

Mark Ewen

Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	**Docket Nos. P-2024-3049343**
	:	**G-2024-3049351**
v.	:	
	:	
Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029 & Affiliated Interest Agreements of UGI Utilities, Inc.	:	

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 Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
debuckley@pa.gov

The Honorable Alphonso Arnold III
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
alphonarno@pa.gov

Allison Kaster, Esquire
Director
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
akaster@pa.gov

Harrison W. Breitman, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
HBreitman@paoca.org

Lindsay Berkstresser, Esquire
Counsel, Energy & Regulatory
UGI Corporation
500 North Gulph Road
King of Prussia, PA 19406
Berkstresserl@ugicorp.com

Anthony D. Kanagy, Esquire
Nicholas A. Stobbe, Esquire
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101-1601
akanagy@postschell.com
nstobbe@postschell.com

Devin T. Ryan, Esquire
Post & Schell, P.C.
One Oxford Centre
301 Grant Street, Suite 3010
Pittsburgh, PA 15219
dryan@postschell.com

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak, LLC
501 Corporate Circle, Suite 302
Harrisburg, PA 17110
tsstewart@hmslegal.com

DATE: September 25, 2024

/s/ Steven C. Gray
Steven C. Gray
Senior Attorney
Assistant Small Business Advocate
Attorney I.D. No. 77538