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File #: 205959

October 22, 2024

VIA ELECTRONIC FILING

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

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 and G-2024-3049351

Dear Secretary Chiavetta:

Attached for filing is the Joint Petition for Approval of Non-Unanimous Settlement and associated Statements in Support thereof on behalf of UGI Utilities, Inc. – Electric Division in the above-referenced proceeding. Copies will be provided as indicated on the Certificate of Service.

Respectfully submitted,

Anthony D. Kanagy

ADK/dmc
Attachments

cc: Honorable Dennis J. Buckley (*via email*)
Honorable Alphonso Arnold, III (*via email*)
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served 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-MAIL

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Date: October 22, 2024

Anthony D. Kanagy

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the period of June 1, 2025 through May 31, 2029	:	Docket Nos. P-2024-3049343 G-2024-3049351
Penn Renewables LLC v. UGI Utilities, Inc. – Electric Division	:	~~C-2024-3049617~~ C-2024-3049618-AEL-10/22/24

JOINT PETITION FOR APPROVAL OF
NON-UNANIMOUS SETTLEMENT

TO ADMINISTRATIVE LAW JUDGES DENNIS J. BUCKLEY AND ALPHONSO ARNOLD III:

I. INTRODUCTION

UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company"), the Office of Consumer Advocate ("OCA"), and the Office of Small Business Advocate ("OSBA"), parties to the above-captioned proceeding (hereinafter, collectively the "Joint Petitioners" or the "Parties"),[1] hereby file this "Joint Petition for Approval of Non-Unanimous Settlement" ("Non-Unanimous Settlement") and respectfully request that presiding Administrative Law Judges Dennis J. Buckley and Alphonso Arnold III (collectively, the "ALJs") and the Pennsylvania Public Utility Commission ("Commission") approve UGI Electric's above-captioned Petition for Approval of Its Default Service Plan for the Period From June 1, 2025 through May 31, 2029 ("Petition" or

[1] The Company notes that Penn Renewables, LLC ("Penn Renewables") is the only party to this proceeding not joining the Non-Unanimous Settlement. The items in this proceeding being litigated are delineated in the Company's Main Brief submitted on October 15, 2024, and in the Company's Reply Brief to be submitted on October 25, 2024.

"DSP V") subject to the terms and conditions of the Non-Unanimous Settlement including the *pro forma* tariff provided as **Appendix A** to be filed on or before May 2, 2025 to become effective June 1, 2025.

Accompanying the Non-Unanimous Settlement are Statements in Support provided by: UGI Electric, the OCA, and the OSBA. These Statements in Support are included, respectively, as **Appendices B** through **D** to the Non-Unanimous Settlement.

In support of the Non-Unanimous Settlement, the Joint Petitioners state the following:

II. BACKGROUND

1. On May 31, 2024, UGI Electric filed the above-captioned petition with the Commission requesting approval for a Default Service Plan ("DSP") for the period of June 1, 2025 through May 31, 2029.

2. In the DSP, UGI Electric proposes to: (1) procure a competitive mix of default service supplies through load-following, block and spot market purchases, and related Alternative Energy Portfolio Standards ("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 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.

3. On June 5, 2024, the Commission issued an Initial Call-In Telephone Hearing Notice, scheduling a Prehearing Conference in this proceeding for Friday, June 28, 2024, at 10:00 a.m. before the ALJs.

4. On June 11, 2024, the Commission issued a Notice to Be Published, directing that Formal Protests, Petitions to Intervene, and Answers must be filed in accordance with Title 52 of the Pennsylvania Code on or before July 12, 2024.

5. On June 13, 2024, the ALJs issued a Prehearing Order directing, among other things, the submission of Prehearing Conference Memorandums on or before June 25, 2024.

6. Also on June 13, 2024, OSBA filed a Notice of Appearance.

7. On June 18, 2024, Penn Renewables filed a Formal Complaint.

8. On June 21, 2024, OCA filed an Answer.

9. On June 25, 2024, UGI Electric, the OCA, the OSBA, and Penn Renewables filed Prehearing Memoranda.

10. On June 28, 2024, the Prehearing Conference took place as scheduled. All parties were present.

11. On July 2, 2024, the ALJs issued a Post Conference Order establishing, among other things, certain modifications to the Commission's discovery rules and a Procedural Schedule.

12. On August 2, 2024, the OCA, OSBA, and Penn Renewables served their respective direct testimonies.

13. On August 19, 2024, the Commission issued a Telephonic Evidentiary Hearings Notice, scheduling telephonic Evidentiary Hearings for September 30, 2024 and October 1, 2024.

14. On August 28, 2024, UGI Electric filed a Motion for Protective Order.

15. On August 30, 2024, UGI Electric, OCA, and OSBA served Rebuttal Testimony. That same day, Penn Renewables filed a letter indicating that it would not be serving Rebuttal Testimony.

16. On September 23, 2024, UGI Electric served Revised UGI Electric Statement Nos.

2 and 2-R – the Direct and Rebuttal Testimony of Stan C. Faryniarz and associated exhibits. Mr. Faryniarz assumed the Direct and Rebuttal Testimony and exhibits previously sponsored by James M. Rouland.

17. On September 25, 2024, OSBA and Penn Renewables served Surrebuttal Testimony.

18. Also on September 25, 2024, Counsel for UGI Electric requested that the ALJs cancel the September 30, 2024 Evidentiary Hearing. Later that day, the ALJs indicated that the request would be granted, and maintained the October 1, 2024 evidentiary hearing date. That day, a Hearing Cancellation Notice was issued for the September 30, 2024 hearing date.

19. On September 26, 2024, the ALJs issued a Protective Order.

20. On October 1, 2024, UGI Electric served written Rejoinder Testimony.

21. Also on October 1, 2024, the Evidentiary Hearing took place as scheduled. There, each party moved to have their witnesses' testimony and exhibits entered into the record. Further, UGI Electric, OCA, and OSBA advised the ALJ that they had reached a Non-Unanimous Settlement Agreement, with Penn Renewables opposing.

22. On October 7, 2024, the ALJs issued a Post-Hearing Order, delineating the briefing schedule, among other things.

23. On October 8, 2024, UGI Electric submitted a Motion to Admit an on the Record Data Request made by Penn Renewables.

24. On October 10, 2024, the ALJs issued an Order Granting Motion to Admit on the Record Data Request.

25. On October 15, 2024, UGI Electric, OCA and Penn Renewables filed Main Briefs. OSBA submitted a letter indicating that it would not be submitting a Main Brief in this proceeding.

26. In support of this Settlement, the Joint Petitioners state as follows:

III. <u>SETTLEMENT TERMS AND CONDITIONS</u>

27. UGI Electric's DSP V filing is approved except as modified herein:

A. DSP V PROGRAM TERM

28. The DSP V program term will be the four-year period beginning on June 1, 2025, through May 31, 2029.

B. PROCUREMENT ISSUES

29. UGI Electric will procure a 10 MW around-the-clock ("ATC") block tranche with a five-year term. UGI Electric will procure another 10 MW ATC block tranche with a two-year term on a rolling basis through the term of DSP V and into the term of DSP VI. UGI Electric's remaining proposed procurement methodologies for GSR-1 and GSR-2 customers as set forth in UGI Electric's Petition for Approval of a DSP for the period of June 1, 2025 through May 31, 2029 and in UGI Electric St. No. 2, the Direct Testimony of Stan C. Faryniarz, pages 12-23, are approved as filed. The bid documents appended to UGI Electric St. No. 2 as Exhibits SCF-4 through SCF-10 are also approved, with the changes to implement the above modification.

30. UGI Electric will continue to procure supplies for GSR-1 residential and non-residential customers on a combined basis. For the DSP V period, the Company will apply rate allocation factors of 1.01 for residential customers and 0.97 for small commercial customers. The allocation factors will expire on May 31, 2029 at the end of DSP V and will not continue into the next DSP period. These provisions do not prevent any party from proposing, or waiving their right to propose, rate allocation factors in the DSP VI proceeding.

31. UGI Electric's 50 percent load cap proposal applicable to fixed-price full-requirements ("FPFR") tranches shall be conditional and apply prospectively to future FPFR

solicitations after the point where UGI receives at least three independent bids for a FPFR solicitation (i.e., not apply to such initial solicitation where three bids are received but thereafter conditionally apply to all future FPFR solicitations). Absent three or more bids, the load cap shall not apply in such future solicitations.

C. RECONCILIATION ISSUES

32. For the GSR-1 customer group, UGI Electric will utilize a 12-month amortization period for over- or under-collections balances reconciled for each six-month period.

33. The GSR-2 reconciliation process will be as set forth in UGI Electric St. No. 3-R, the Rebuttal Testimony of Tracy A. Hazenstab, page 15, and Exhibit TAH-2R.

D. GSR-1/GSR-2 CUSTOMER CLASSIFICATION

34. UGI Electric's proposal to classify GSR-1 and GSR-2 customers based upon their supply peak load impact is approved. UGI Electric St. No. 2, p. 29.

E. STATUTORY FINDINGS

35. As set forth in Paragraph 92 of the Petition, the Joint Petitioners request that the ALJs and the Commission make the findings under 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.

IV. <u>UNRESOLVED ISSUES</u>

36. As noted above, Penn Renewables opposed the Non-Unanimous Settlement. Penn Renewables' issues are being briefed by the parties. UGI Electric submitted a Main Brief

addressing these issues separately on October 15, 2024, and will submit a Reply Brief responsive to Penn Renewables Main Brief on October 25, 2024.

V. <u>THE NON-UNANIMOUS SETTLEMENT IS IN THE PUBLIC INTEREST</u>

50. Commission policy promotes settlements. *See* 52 Pa. Code § 5.231. Settlements lessen the time and expense the Parties must expend litigating a case and, at the same time, conserve administrative resources. The Commission has indicated that settlement results are often preferable to those achieved at the conclusion of a fully litigated proceeding. *See id.* § 69.401. In order to accept a settlement, the Commission must first determine that the proposed terms and conditions are in the public interest. *Pa. PUC v. York Water Co.*, Docket No. R-00049165 (Order entered Oct. 4, 2004); *Pa. PUC v. C.S. Water and Sewer Assocs.*, 74 Pa. P.U.C. 767 (1991).

51. This Non-Unanimous Settlement was achieved by the Joint Petitioners after an extensive investigation of UGI Electric's filing, including extensive formal discovery and the filing of substantial testimony by the active Parties.

52. The Joint Petitioners will further supplement the reasons that the Non-Unanimous Settlement is in the public interest in their Statements in Support. The Statements in Support are attached to this Non-Unanimous Settlement as Appendices B through D. In their respective Statements in Support, each Joint Petitioner explains why, in its view, the Non-Unanimous Settlement is fair, just, and reasonable and reflects a reasonable compromise of the disputed issues in this proceeding.[2]

VI. <u>SETTLEMENT CONDITIONS</u>

53. The Joint Petition for Non-Unanimous Settlement is conditioned upon the Commission's approval of the terms and conditions contained herein without modification. If the

[2] It is noted that, because certain Joint Petitioners only participated with regard to certain issues in this proceeding, some of the Statements in Support may be limited in the scope of issues addressed.

Commission modifies the Joint Petition for Non-Unanimous Settlement, any Settlement Party may elect to withdraw from the Joint Petition for Non-Unanimous Settlement and may proceed with litigation and, in such event, the Settlement shall be void and of no effect. Such election to withdraw must be made in writing, filed with the Secretary of the Commission and served upon all Parties within five (5) business days after the entry of an Order modifying the Non-Unanimous Settlement.

54. This Non-Unanimous Settlement is proposed by the Settlement Parties to this Joint Petition for Non-Unanimous Settlement to settle and forever resolve all issues in the instant proceeding. If the Commission does not approve the Non-Unanimous Settlement and the proceedings continue, the Settlement Parties reserve their respective procedural rights. The Joint Petition for Non-Unanimous Settlement is made without any admission against, or prejudice to, any position which any Settlement Party may adopt in the event of any subsequent litigation of these proceedings, or in any other proceeding.

55. The Settlement Parties acknowledge and agree that this Non-Unanimous Settlement, if approved, shall have the same force and effect as if the Settlement Parties had fully litigated these proceedings.

56. This Non-Unanimous Settlement and its terms and conditions may not be cited as precedent in any future proceeding, except to the extent required to implement this Non-Unanimous Settlement.

57. The Joint Petitioners acknowledge that the Joint Petition for Non-Unanimous Settlement reflects a compromise of competing positions and does not necessarily reflect any party's position with respect to any issues raised in this proceeding. The Settlement Parties agree that the Joint Petition for Non-Unanimous Settlement shall not constitute or be cited as precedent

in any other proceeding, except to the extent required to implement the Joint Petition for Non-Unanimous Settlement.

58. The Settlement Parties agree to support this Joint Petition for Non-Unanimous Settlement in any Statements in Support.

59. The Joint Petition for Non-Unanimous Settlement may only be amended by a written document duly agreed to and executed by the Settlement Parties.

60. The Settlement Parties will present their reasons why the Joint Petition for Non-Unanimous Settlement is in the public interest in their Statements in Support of Settlement, attached hereto as Appendices B through D.

VII. CONCLUSION

WHEREFORE, the Joint Petitioners respectfully request that the Honorable Administrative Law Judges Dennis J. Buckley and Alphonso Arnold III and the Pennsylvania Public Utility Commission: (1) approve the default service program set forth in the Petition as modified by this Non-Unanimous Settlement; (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, if necessary, 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 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; (8) make the findings set forth in Paragraph 92 of the Petition and Paragraph 35 of this Non-Unanimous Settlement, and (9) grant such other relief as the Commission deems appropriate.

Respectfully submitted,

Date: October 22, 2024

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Date: 10/22/2024

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APPENDIX A

Pro Forma Tariff

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 or not larger than 3,000 kilowatts at other **(C)** customer service locations, except for a Customer whose system is above 3 megawatts and **(C)** 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.

(4) Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy **(C)** 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 final billing period on or before the end of the PJM year (May of **(C)**
each year). At the end of each PJM year, the Company will compensate the customer-generator for **(C)**
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 Customer's applicable Price to Compare (PTC-1 or PTC-2). Applicable PTC-2 rates shall be applied to the respective hours of **(C)**
excess generation. The customer-generator is responsible for the customer charge, demand charge **(C)**
and other applicable charges under the applicable Rate Schedule.

(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 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 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, 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 in accordance with the following: **(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)**

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. For new Customers without a twelve-month billing history, the 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 six months beginning June 1, 2025. The GSR-1 rate shall be filed with the Commission with at least thirty days' notice prior to each 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-1 = (((EC*F)/SEC) + (ECA/SECA) + (Int/Sint)) * (1/(1-T)) **(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 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. **(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	1.01	0.97

(C)

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 based on actual EC revenues received and actual EC costs incurred for the six-month period ending two months prior to the filed GSR effective date. The ECA shall be amortized over a twelve-month period for balances reconciled for each six-month period. **(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 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 next computation period, in kilowatt hours. **(C)**

(C)

The current GSR-1 rate (in ¢/kWh) is: **(C)**

Residential	Non-Residential
x.xx	x.xx

(C)

(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 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. **(C)**

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 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)**

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 Compare ("PTC") for GSR-1 (PTC-1) shall 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. 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 the preceding 12 months ending May 31. **(C)**

(C) Indicates Change

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)**

$$GSR\text{-}1 = (((EC*F)/SEC) + (ECA/SECA) + (Int/Sint)) * (1/(1-T))$$ **(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	1.01	0.97

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 based on actual EC revenues received and actual EC costs incurred for the six-month period ending two months prior to the filed GSR effective date. The ECA shall be amortized over a twelve-month period for balances reconciled for each six-month period. ~~The ECA will be reconciled quarterly based on actual EC revenues received and actual EC costs incurred for the three-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-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)**

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)** **(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)** **(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)**

(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) Indicates Change

Issued:	Effective for Service Rendered on and after

APPENDIX B

Statement In Support

UGI Utilities, Inc. – Electric Division

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the period of June 1, 2025 through May 31, 2029	:	Docket Nos. P-2024-3049343 G-2024-3049351
Penn Renewables LLC v. UGI Utilities, Inc. – Electric Division	:	C-2024-3049617

UGI UTILITIES, INC. – ELECTRIC DIVISION'S STATEMENT IN SUPPORT OF JOINT PETITION FOR NON-UNANIMOUS SETTLEMENT

TO ADMINISTRATIVE LAW JUDGES DENNIS J. BUCKLEY AND ALPHONSO ARNOLD III:

I. INTRODUCTION

UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") hereby files this Statement in Support of the Joint Petition for Non-Unanimous Settlement ("Non-Unanimous Settlement") entered into by the Company, the Office of Consumer Advocate ("OCA"), and the Office of Small Business Advocate ("OSBA") (hereinafter, collectively the "Joint Petitioners" or the "Parties").[1] As explained herein, the Non-Unanimous Settlement resolves all of the issues that have been raised concerning UGI Electric's fifth Default Service Plan ("DSP V" or the "Plan") as between the Company, OCA, and OSBA. DSP V establishes the terms and conditions under which the Company will acquire default service supplies, including Alternative Energy Portfolio

[1] The Company notes that Penn Renewables, LLC ("Penn Renewables") is the only party to this proceeding not joining the Non-Unanimous Settlement. The items in this proceeding being litigated are delineated in the Company's Main Brief submitted on October 15, 2024, and in the Company's Reply Brief to be submitted on October 25, 2024, as noted in Section III (F), *infra*.

Standards ("AEPS") credits, from June 1, 2025, through May 31, 2029 ("DSP V Term").

UGI Electric respectfully requests that Administrative Law Judges Dennis J. Buckley and Alphonso Arnold III (collectively, the "ALJs") and the Pennsylvania Public Utility Commission ("Commission") approve the above-captioned Petition for Approval of a Default Service Plan for the Period of June 1, 2025 through May 31, 2029 ("Petition") subject to the terms and conditions of the Non-Unanimous Settlement. The Non-Unanimous Settlement reflects a carefully balanced compromise of the Joint Petitioners' interests and the issues they raised in this proceeding.

For these reasons and as explained in more detail below, the Non-Unanimous Settlement is in the public interest, just and reasonable, and supported by substantial evidence and, therefore, should be approved without modification.

II. STANDARD FOR APPROVAL OF A SETTLEMENT

Commission policy promotes settlements. *See* 52 Pa. Code § 5.231. Settlements reduce the time and expense that the parties must expend litigating a case, and at the same time, conserve precious administrative resources. The Commission has indicated that settlement results are often preferable to those achieved at the conclusion of a fully litigated proceeding. *See* 52 Pa. Code § 69.401. The Commission has explained that parties to settled cases are afforded flexibility in reaching amicable resolutions, so long as the settlement is in the public interest. *Pa. PUC v. MXenergy Electric Inc.*, Docket No. M-2012-2201861, 2013 Pa. PUC LEXIS 789 (Opinion and Order entered Dec. 5, 2013). In order to accept a settlement, the Commission must first determine that the proposed terms and conditions are in the public interest. *Pa. PUC v. Windstream Pennsylvania, LLC*, Docket No. M-2012-2227108, 2012 Pa. PUC LEXIS 1535 (Opinion and Order entered Sept. 27, 2012); *Pa. PUC v. C.S. Water and Sewer Assoc.*, Docket No. R-881147, 74 Pa. PUC 767 (Opinion entered Jul. 22, 1991).

The Commission's policy permits parties to enter "partial" or "non-unanimous" settlements. *See* 52 Pa. Code § 69.401. *See also* 52 Pa. Code § 5.232, § 69.406. As with full settlements, partial settlements, whether involving a partial settlement of issues or a partial settlement of the parties involved (non-unanimous), must be reasonable and in the public interest. *See Pa. PUC v. City of Bethlehem – Water Department*, Docket No. R-2020-3020256, 2021 Pa. PUC LEXIS 116 (April 15, 2021) ("*City of Bethlehem Water*"). The Commission has approved non-unanimous settlements as being just and reasonable and in the public interest and has not rejected or disfavored settlements because they are non-unanimous. *See, e.g. Pa. PUC v. Peoples Natural Gas Company* LLC, Docket Nos. R-2023-3044549, *et al*. (Order entered Sept. 12, 2024); *Pa. PUC v. Columbia Gas of Pa., Inc.*, Docket Nos. R-2022-3031211, *et al.* (Opinion and Order entered Dec. 8, 2022); *City of Bethlehem Water*; *Pa. PUC v. Pike County Light and Power Company – Electric*, Docket No. R-2020-3022135 (Recommended Decision May 5, 2021; Order entered June 23, 2021) ("*Pike County*"); *Pa. PUC v. Pennsylvania-American Water Company*, Docket No. R-2020-3019369 (Order entered Feb. 25, 2021).

The standards for approving the terms of non-unanimous settlements are the same as those for deciding a fully contested case, *i.e.* the parties to the non-unanimous settlement must demonstrate that the proposed settlement is supported by substantial evidence and that the rates agreed to are just and reasonable and in conformity with the Commission's orders and regulations. *See* 66 Pa C.S. § 1301; *Pike County*, Docket No. R-2020-3022135. Also relevant to the Commission's approval of a non-unanimous settlement is the due process afforded to non-settling parties, such as whether non-settling parties were provided an opportunity to object to the settlement and to present their positions on the issues, and the range of interests represented in the non-unanimous settlement. *City of Bethlehem Water*, 2021 Pa. PUC LEXIS 116. In this case, the non-settling party to the Joint Petition for Non-Unanimous Settlement, *i.e.*, Penn Renewables, is given an opportunity to submit briefs on the issues addressed in the Non-Unanimous Settlement. In addition, the Non-Unanimous Settlement will be served on all parties to the proceeding, and the ALJs have established procedures for filing comments in opposition thereto. *See Post-Hearing Order*, ¶ 2, Docket Nos. P-2024-3049343, *et al*., (Order issued October 7, 2024). As explained in the next section of this Statement in Support, UGI Electric believes that the Non-Unanimous Settlement is just, reasonable, in the public interest, and should be approved without modification.

III. THE SETTLEMENT IS IN THE PUBLIC INTEREST

The Non-Unanimous Settlement is just, reasonable, in the public interest, and is supported by substantial evidence. The Non-Unanimous Settlement was achieved only after a comprehensive investigation of UGI Electric's DSP V. In addition to a comprehensive filing, UGI Electric responded to numerous formal discovery requests (many of which had multiple subparts). In support of their respective positions, UGI Electric, OCA, and OSBA served testimony and accompanying exhibits.[2] The Joint Petitioners participated in numerous settlement discussions and formal negotiations, which ultimately led to the Non-Unanimous Settlement.

The Non-Unanimous Settlement reflects a carefully-balanced compromise of the interests of all of the Joint Petitioners. (Non-Unanimous Settlement ¶ 52.) The Joint Petitioners, as well as their experts and counsel, have considerable experience in default service proceedings. Their knowledge, experience, and ability to evaluate the strengths and weaknesses of their litigation positions provided a strong base upon which to attempt to build a consensus in this proceeding. The fact that the Non-Unanimous Settlement is supported by Joint Petitioners representing

[2] Penn Renewables, who is opposing the Non-Unanimous Settlement, also submitted Direct and Surrebuttal Testimony.

different constituents and interests, in and of itself, provides strong evidence that the Non-Unanimous Settlement is reasonable and in the public interest.

For these reasons and the more specific reasons set forth below, the Non-Unanimous Settlement, as a whole, is just, reasonable, and in the public interest. Therefore, the terms and conditions of the Settlement should be approved without modification. (Non-Unanimous Settlement ¶¶ 27-35; 53-60.).

A. DSP V PROGRAM TERM

In its DSP V Petition, UGI Electric proposed that the DSP V program term will be the four-year period beginning on June 1, 2025, through May 31, 2029. UGI Electric St. No. 1, p. 4. The Commission previously approved a four-year term for the Company's DSP III and DSP IV plans. UGI Electric St. No. 1, p. 5. Furthermore, UGI Electric noted that the Commission has approved four-year default service plans for other default service suppliers, including: (1) PPL Electric Utilities Corporation, (2) Duquesne Light Company; (3) the FirstEnergy Companies, and (4) PECO Energy Company. *Id.*

No party took issue with or opposed the Company's proposed four-year DSP V term. As such, the Non-Unanimous Settlement reflects UGI Electric's proposal to implement a four-year DSP V term, as has been the case for both UGI Electric's DSP III and IV terms. (Non-Unanimous Settlement ¶ 28.) UGI Electric submits that this Non-Unanimous Settlement term is just, reasonable, and in the public interest and should be approved without modification as it merely confirms and accepts UGI Electric's proposal consistent with UGI Electric's past two DSP terms, and consistent with other Electric Distribution Companies' ("EDC") DSP terms.

B. PROCUREMENT ISSUES

1. GSR-1 PROCUREMENT GROUP

UGI Electric's GSR-1 procurement group includes residential and small commercial customers with up to 100 kW of supply peak load impact ("SPLI"). UGI Electric has historically procured power for residential and small commercial customers on a combined basis due to the relatively small load sizes of both groups. One of the primary if not the primary goal of the GSR-1 procurement plan is to ensure that load size and tranches are large enough to attract sufficient wholesale bidder interest and reduce bid premiums.

To pursue its goals and obligations under DSP V, the Company proposed certain differences between the Commission-approved DSP IV Plan and the proposed DSP V Plan. The Company's proposed changes as between DSP IV and DSP V are delineated in the table below:

	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
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
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.

UGI Electric St. No. 2, pp. 11-12; UGI Electric Exh. No. SCF-2.

The changes to the proposed product mix from DSP IV to DSP V include relying more on fixed price full requirements ("FPFR") contracts and longer-term block purchases. As noted above, the primary goal was to ensure sufficient load and tranche sizes to maximize supplier participation for all products by reducing risk for suppliers due to product/portfolio design, increasing competition for those products and reducing costs for GSR-1 customers. This will provide greater price stability over time and ensure that GSR-1 rates are least cost over time. UGI Electric St. No. 2, p. 8. UGI Electric St. No. 3, p. 11.

In response to the Company's proposed procurement plans and methodology, OCA, OSBA, and Penn Renewables all submitted responsive testimony in accordance with the procedural schedule adopted in the case.

In Direct Testimony, the OCA recommended that the residential and small commercial default service supply portfolio consist of 100 percent 24-month 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. OCA St. No. 1, p. 4. Further, the OCA recommended that: (1) the Company set the GSR-1 FPFR "tranche" cap to 75% if the OCA's recommended GSR-1 default service supply portfolio is adopted to "strike a better balance" between maximizing competition and limiting exposure to a single wholesale supplier; (2) the Company clarify its 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) the Commission reject the Company's proposal, based on the findings of its Procurement Study, to adopt rate allocation factors that were approximately 10% higher for residential customers than for non-residential GSR-1 customers. OCA St. No. 1, pp. 4-5; 21. Additionally, the OCA recommended that the Commission adopt a 12-month amortization period for over- or under-collection balances reconciled over a six-month period for the GSR-1 customer class. OCA St. No. 1, p. 10.

In Direct Testimony, the OSBA indicated that it was continuing to evaluate the Company's proposal with respect to its GSR-1 procurement strategy. OSBA St. No. 1, p. 6. The OSBA also noted that it found that UGI Electric's Procurement Study's conclusion related to separate versus combined procurements for residential and non-residential GSR-1 customers to be reasonable. OSBA St. No. 1, p. 8. In doing so, the OSBA supported the assignment of separate GSR-1 rates to residential and non-residential GSR-1 customers. OSBA St. No. 1, p. 8.

In Rebuttal Testimony, UGI Electric addressed the various issues raised by OCA, OSBA, and Penn Renewables. First, in response to OCA and OSBA, UGI Electric witness Tyahla explained that the Company believed that maintaining the status quo of combined procurements for residential and non-residential GSR-1 customers was appropriate and that the Company proposed to remove rate allocation factors. UGI Electric St. No. 1-R, pp. 7-8.

Next, UGI Electric witness Mr. Faryniarz disagreed with the OCA's recommendation to move to 100% 24-month FPFR contracts, explaining that UGI Electric's proposal included a detailed approach to stabilize the risk of PJM capacity in the event market-based prices are not established for the term being bid on in a given solicitation, thereby reducing risk. UGI Electric St. No. 2-R, p. 7. Mr. Faryniarz also disagreed with OCA's contention that the Company could easily procure 24-month FPFR contracts. UGI Electric St. No. 2-R, p. 12. The Company further disagreed with OCA's recommendation to implement a 75% load cap for its FPFR portfolio, as doing so would require bifurcation of the 50% tranche(s), undermining the Company's intent to maintain a larger tranche MW size, which would likely reduce cost and increase supplier interest in bidding. UGI Electric St. No. 2-R, pp. 14-15.

Additionally, through rebuttal, UGI Electric disagreed with the OCA's proposal to conduct separate procurements for residential and non-residential GSR-1 customers if the rate allocation factors are not eliminated. UGI Electric St. No. 2-R, p. 16. Mr. Faryniarz explained that doing so would be detrimental to both residential and non-residential customers in the GSR-1 rate group, because it would reduce tranche size and limit the types of products to be procured, thereby likely resulting in increased costs and/or failed bids resulting in a default to the volatile spot market supply. The Company agreed with OCA's recommendation to utilize a 12-month amortization period for over- or under-collections balances reconciled over a six-month period for GSR-1 customers. UGI Electric St. No. 3-R, pp. 14-15.

In Rebuttal Testimony, the OCA continued to recommend that the residential and small commercial default service supply portfolio consist of 100 percent 24-month PFPR contracts, after a 12-month FPRP contract and an 18-month FPFR contract as "catch-up procurements to start DSP V, OCA St. No. 1R, pp. 3-4. OCA also argued that UGI Electric should continue to conduct a joint procurement process for residential and small commercial GSR-1 customers and establish a single GSR-1 EC rate and a single GSR-1 PTC applicable to all GSR-1 customers. OCA St. No. 1R, p. 7.

The OSBA also submitted Rebuttal Testimony responsive to the OCA's Direct Testimony. Specifically, OSBA argued that OCA's concerns about the Procurement Study were over-stated. OSBA St. No. 1-R, p. 4. In rebuttal, the OSBA continued to argue that the Company's Procurement Study's methodology and assumptions are sound, and that OCA failed to provide "sufficient evidence that challenges or invalidates the results of the Procurement Study." OSBA St. No. 1-R, p. 6. Therefore, OSBA continued to recommend that the Commission approve the as filed Company's proposed rate structure for the GSR-1 class with separate rate allocation factors for residential and small commercial GSR-1 customers. OSBA St. No. 1-R, p. 6.

In Surrebuttal, OCA continued to recommend that the Company transition into 100% 24-month FPFR contracts. OCA St. No. 1SR, pp. 5-9. OCA also continued to argue that 24-month FPFR contracts are not too risky for wholesale suppliers. OCA St. No. 1SR, p. 9. OCA also explained that its recommendation does not expose GSR-1 customers to the risk of a single product, arguing that "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. OCA St. No. 1SR, pp. 11-12. OCA further recommended that, should the Commission approve UGI Electric's proposed portfolio, then UGI Electric should procure one 10 MW block with a five-year term and one 10 MW block with rolling 24-month terms. OCA St. No. 1SR, pp. 13-14. Further, OCA continued to recommend that the Company's 50% load cap proposal for FPFR contracts be rejected, and a 75% load cap be implemented. OCA St. No. 1SR, p. 14. OCA also continued to disagree with OSBA's positions with respect to the procurement study. OCA St. No. 1SR, pp. 17-26.

In Surrebuttal, the OSBA acknowledged the Company's agreement to withdraw its EC multiplier component proposal and disagreed with the same because doing so would be unfair to small business customers and be inconsistent with cost causation. OSBA St. No. 1-SR, pp. 2-3. OSBA also reaffirmed its support for the Company's proposed classification of GSR-1 and GSR-2 customers, and requested a point of clarification from the Company with respect to its waiver request of the 25 kW peak load threshold in order for large customer generators to be classified as GSR-2 default service customers.

Through Rejoinder Testimony, the Company confirmed that the requested waiver included as part of the DSP Petition 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, responsive to the OSBA's request for clarification in Surrebuttal Testimony. UGI Statement No. 3-RJ, p. 13.

The Non-Unanimous Settlement resolves all of the above-identified procurement issues as between the Joint Petitioners and reflects a carefully crafted compromise of the competing interests present in this proceeding. Specifically, under the Non-Unanimous Settlement, the Joint Petitioners agree that UGI Electric will procure a 10 MW ATC block tranche with a five-year term. UGI Electric will procure another 10 MW ATC block tranche with a two-year term on a rolling basis through the term of DSP V and into the term of DSP VI. (Non-Unanimous Settlement ¶ 29.) This reflects a compromise as between the Company's and the OCA's litigation positions on this issue. This provision serves to enhance rate stability and mirrors similar procurements made by other Pennsylvania EDCs and, therefore, are just, reasonable, in the public interest, and should be approved without modification.

Similarly, the Non-Unanimous Settlement confirms that the Company's other remaining procurement methodologies for GSR-1 and GSR-2 customers as set forth in UGI Electric's Petition for Approval of a Default Service Plan for the period of June 1, 2025 through May 31, 2029 and in UGI Electric St. No. 2, the Direct Testimony of Stan C. Faryniarz, pages 12-23, are approved as filed. (Non-Unanimous Settlement ¶ 29.) Furthermore, the Non-Unanimous Settlement dictates that the bid documents appended to UGI Electric St. No. 2 as Exhibits SCF-4 through SCF-10 are also approved, with the changes to implement the above modification. (Non-Unanimous Settlement ¶ 29.) The Company designed its procurement methodologies to improve supplier participation, competition, and overall supplier diversity which, ultimately, will provide more reliable competitive products and achieve price benefits for UGI Electric's default service customers. The Non-Unanimous Settlement confirms the efficacy of the proposal as modified; as a result, UGI Electric submits that these provisions are just, reasonable, in the public interest, and should be approved without modification.

In its filing, the Company proposed a residential rate allocation factor of 1.02, and a non-residential rate allocation factor of 0.93. UGI Electric St. No. 3, p. 11. Under the Non-Unanimous Settlement, the Joint Petitioners have agreed that UGI Electric will continue to procure supplies for GSR-1 residential and non-residential customers on a combined basis. (Non-Unanimous Settlement ¶ 30.) However, the Joint Petitioners have also agreed that, in doing so, the Company will also apply rate allocation factors of 1.01 for residential customers and 0.97 for small commercial customers and that the allocation factors will expire on May 31, 2029 at the end of DSP V and will not continue into the next DSP period. (Non-Unanimous Settlement ¶ 30.) These provisions do not prevent any party from proposing, or waiving their right to propose, rate allocation factors in DSP VI. (Non-Unanimous Settlement ¶ 30.)

This represents a fulsome compromise between the Company and the OCA's litigation positions by bringing both allocation factors closer to even. In turn, this lowers the costs for residential customers, and slightly increases the costs for non-residential customers as compared to the as-filed Petition, while still adhering to the spirit of the conclusions reached in the Company's procurement study in reviewing EC rates for both customer groups. Therefore, this provision is just, reasonable, in the public interest and should be approved without modification.

Lastly, under this section of the Non-Unanimous Settlement, the Joint Petitioners have agreed that UGI Electric's 50 percent load cap proposal applicable to FPFR tranches shall be conditional and apply prospectively to future FPFR solicitations after the point where UGI Electric receives at least three independent bids for a FPFR solicitation (i.e., not apply to such initial solicitation where three bids are received but thereafter conditionally apply to all future FPFR solicitations). Absent three or more bids, the load cap shall not apply in such future solicitations. (Non-Unanimous Settlement ¶ 31.) This Non-Unanimous Settlement provision reflects a compromise between the Company's and the OCA's respective litigation positions on this issue and addresses the OCA's concerns that a lower cap may decrease supplier participation. OCA St. No. 1, p. 21. Therefore, this provision is just, reasonable, in the public interest and should be approved without modification.

2. GSR-2 PROCUREMENT

In this proceeding, UGI Electric proposed to continue to procure supplies for GSR-2 customers (customers with SPLI of 100 kW or higher) through the spot market. UGI Electric St. No. 2, pp. 21-22. The Commission has approved hourly spot market pricing for GSR-2 customers since its DSP II proceeding. UGI Electric M.B., p. 13. UGI Electric procures default supplies for GSR-2 customers through the spot market pursuant to the Commission's End State Order. UGI Electric M.B., p. 13. No party challenged the Company's proposal to continue to procure spot market supplies for GSR-2 customers. However, Penn Renewables has challenged the Company's proposal to classify GSR-1 and GSR-1 customers based upon their respective SPLI. This issue is discussed further below and in the Company's Main and Reply Briefs.

C. RECONCILIATION ISSUES

In this proceeding, the Company proposed that over- or under-collections over a six-month period for the GSR-1 customer class would be amortized over a subsequent 6-month period. UGI Electric St. No. 3, p. 14. In doing so, the Company proposed to recover the over/under collection for January 1, 2024 – March 31, 2025, over the six-month period of June 1, 2025 – November 30, 2025. *Id.* Thereafter, the June 1 rate would capture the actual over/under collection for the period of October 1 – March 31 and the December 1 rate would calculate the actual over/under collection for the period April 1 – September 30. *Id.*

In response, the OCA recommended that, for the GSR-1 class: "to avoid the administrative complexity associated with determining the residential rate impact of a reconciliation balance and ending the rate stability benefit of a longer-term amortization to all rate periods, [OCA] recommend[s] that the Commission adopt a 12-month amortization period for over- or under-collection balances reconciled over a 6-month period." OCA St. No. 1, p. 10.

Through the Non-Unanimous Settlement, the Company agreed with the OCA's recommendation on this point with the respect to the GSR-1 customer class. As such, the Non-Unanimous Settlement requires the Company to utilize a 12-month amortization period for over- or under-collections reconciled for each six-month period. (Non-Unanimous Settlement ¶ 32.) The Settlement also memorializes UGI Electric's proposal with respect to reconciliation of the GSR-2 customer class as outlined by Ms. Hazenstab. UGI Electric St. No. 3-R, p. 15; Exhibit No. TAH-2R. (Non-Unanimous Settlement ¶ 33.) Both of these commitments extend the rate stability of longer-term amortization, and avoids administrative complexity, thereby addressing the OCA's concerns. Therefore, UGI Electric submits these provisions are just, reasonable, in the public interest and should be approved without modification.

D. GSR-1/GSR-2 CUSTOMER CLASSIFICATION

In the Petition, UGI Electric proposed to classify customers into the GSR-1 and GSR-2 groups based upon their SPLI. UGI Electric St. No. 3, p. 3. UGI Electric proposed to classify customers into the GSR-1 group if they have a SPLI of less than 100 kW and into the GSR-2 group if they have an SPLI greater than or equal to 100 kW. UGI Electric St. No. 3, p. 4. This change was explained by Ms. Hazenstab, who reasoned that:

> 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.

UGI Electric St. No. 3, p. 5.

In Direct Testimony, Penn Renewables disagreed with UGI Electric's proposal to classify customer-generators with more than 100 kW of SPLI as GSR-2 customers. Penn Renewables St. No. 1, pp. 19-20. Further, Penn Renewables recommended that the threshold for an account to be classified as GSR-2 be raised from 100 kW to 3MW. Penn Renewables St. No. 1, p. 28.

In rebuttal, Ms. Hazenstab and Mr. Faryniarz addressed and disagreed with Penn Renewables objections to UGI Electric's proposed classification of GSR-1 and GSR-2 customers. See UGI Electric St. No. 3-R, pp. 3-14. UGI Electric St. No. 2-R, pp. 18-33. Mr. Faryniarz explained 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 perspective. UGI Electric St. No. 2-R, p. 18. Large customer-generators are likely to export a substantial amount of energy and are likely to impact the overall default supply (MW and MWh) which is also likely to impact the competitiveness of bids from wholesale suppliers. UGI Electric St. No. 2-R, p. 18. Indeed, of the 30 new large customer-generator applications received, the total prospective generation would represent approximately 6% of UGI Electric's GSR-1 load, which would likely result in higher bid prices and/or lower supplier participation for a GSR-1 program that is challenged with both issues already. UGI Electric St. No. 2-R, p. 19. These are precisely the problems that UGI Electric seeks to resolve through its DSP V Plan, and by the Non-Unanimous Settlement. *Id.*

In rebuttal, the OCA also disagreed with Penn Renewables' conclusions with respect to the classification of customers into the GSR-1 and GSR-2 procurement groups, as doing so 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." OCA St. No. 1R, p. 11. In doing so, this would negatively impact residential default service customers by: (1) the FPFR suppliers building larger risk premiums into their contract bids or shying away from participating in FPFR auctions, thereby likely creating higher PTCs and/or more volatile rates for residential customers; and (2) increasing volumetric risk for FPFR suppliers because of the uncertainty surrounding the level and profile of on-site generation. OCA St. No. 1R, pp. 11-12. The OCA also rejected Penn Renewables recommendation that the threshold for an account to be classified as GSR-2 be raised from 100 kW to 3MW if the Commission authorizes to compensate GSR-2 customer-generators based on Locational Marginal Price ("LMP"). OCA St. No. 1R, p. 9.

Penn Renewables submitted Surrebuttal Testimony on the issues identified in its Direct Testimony. *See* Penn Renewables St. No. 1-SR.

OSBA also submitted Surrebuttal Testimony supporting UGI Electric's proposal to classify large customer-generators as GSR-2 customers, noting that "OSBA supports the Company's proposal and agrees with the points laid out in the rebuttal testimonies of Witness [Faryniarz][3] and Witness Hazenstab." OSBA St. No. 1-SR, p. 3.

UGI Electric submitted responsive written Rejoinder Testimony again refuting Penn Renewables' contentions and claims related to the Company's timely development of customer-generator projects on its system and its proposal to classify large customer-generators as GSR-2 customers. *See* UGI Electric St. No. 2-R; UGI Electric St. No. 2-R, pp. 2-13.

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[3] On September 23, 2024, UGI Electric submitted the Direct and Rebuttal Testimony of Stan C. Faryniarz – UGI Electric Statement Nos. 2 (Revised) and 2-R (Revised). The revisions to both UGI Electric Statement Nos. 2 and 2-R accounted for Mr. Faryniarz's assumption of what was previously served as UGI Electric Statement Nos. 2 and 2-R – the Direct and Rebuttal Testimony of James. M. Rouland. Mr. Faryniarz replaced Mr. Rouland as a witness in this proceeding due to the fact that Mr. Rouland took another job and was no longer available to testify. The substantive content of the testimony was not revised. The revisions primarily accounted for the change in the witness sponsoring each piece of aforementioned testimony, as well as adjustments to the titling of those testimonies' associated exhibits.

The Penn Renewables' issues related to the classification of the GSR-1 and GSR-2 customer classes are addressed fully in the Company's Briefs and will not be wholly addressed here. However, UGI Electric notes that the Company's proposals with respect to the classification of GSR-1 and GSR-2 customers based on their SPLI is supported by both OCA and OSBA. (Non-Unanimous Settlement ¶ 34.) As such, and because the Company's proposal: (1) is necessary for the Company to meet its statutory requirement to provide least cost rates over time; and (2) would prevent subsidization of large customer generators by residential and small commercial customers, this settlement provision is just, reasonable, in the public interest, and should be approved without modification.

E. STATUTORY FINDINGS

As a result of the Non-Unanimous Settlement, the Joint Petitioners agree that the Commission should make the statutory findings under 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.

(Non-Unanimous Settlement ¶ 35.)

These recommended statutory findings are reflective of the carefully compromised Non-Unanimous Settlement detailed above, which was reached as a result of the submission of Direct Testimony by the Company, OCA, and OSBA, the Rebuttal testimony of the Company, OCA, and OSBA, the Surrebuttal Testimony of OCA and OSBA, and the Rejoinder Testimony of the Company. As noted in Sections III (A)-(D) above, substantial concessions have been made between the Joint Petitioners' respective litigation positions, and those concessions are memorialized in the Non-Unanimous Settlement agreed to by the Joint Petitioners, all of whom have significant experience and expertise in evaluating default service proposals. Therefore, UGI Electric submits that the Settlement Provisions related to the requested statutory findings included in Non-Unanimous Settlement ¶ 35 are just, reasonable, in the public interest and should be approved without modification.

F. UNRESOLVED ISSUES

As noted above, Penn Renewables is opposing the Non-Unanimous Settlement with respect to certain issues. Penn Renewables' issues are being briefed by the parties. UGI Electric submitted a Main Brief addressing these issues separately on October 15, 2024, and will submit a Reply Brief responsive to Penn Renewables Main Brief on October 25, 2024.

IV. CONCLUSION

This Non-Unanimous Settlement is the result of detailed examination of UGI Electric's proposed DSP V filing, extensive discovery by the parties, multiple rounds of testimony, and reasonable compromise by knowledgeable Joint Petitioners. The Company believes that a fair and reasonable compromise of all issues has been achieved in this case as between the Joint Petitioners. UGI Electric fully supports the Non-Unanimous Settlement and respectfully requests that Administrative Law Judges Dennis J. Buckley and Alphonso Arnold III recommend, and the Pennsylvania Public Utility Commission approve, the Company's DSP V filing as modified by the Non-Unanimous Settlement without any modification to the terms proposed in the Non-Unanimous Settlement. Further, UGI Electric requests that the ALJs and Commission grant any necessary waivers of the Commission's regulations, if any, for UGI Electric to implement its default service plan as modified by the Non-Unanimous Settlement.

Respectfully submitted,

Date: October 22, 2024

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APPENDIX C

Statement In Support

Office of Consumer Advocate

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the period of June 1, 2025 through May 31, 2029	:	Docket No. P-2024-3049343

STATEMENT OF THE OFFICE OF CONSUMER ADVOCATE
IN SUPPORT OF THE JOINT PETITION FOR APPROVAL OF SETTLEMENT

The Office of Consumer Advocate (OCA), a signatory party to the Joint Petition for Approval of Non-Unanimous Settlement (Settlement) in the captioned proceeding, respectfully requests that the terms and conditions of the Settlement be approved without modification by Administrative Law Judges (ALJs) Dennis Buckley and Alphonso Arnold, and the Pennsylvania Public Utility Commission (Commission). The OCA supports the Settlement as it is supported by substantial evidence in the record, is in the public interest, and in the interests of the residential customers of UGI Utilities, Inc. – Electric Division (UGI or the Company).

I. BACKGROUND

The OCA adopts the Background as set forth in the Joint Petition for Approval of Settlement, Paragraphs 1 through 26. In addition to the background outlined in the Settlement, the OCA notes simply that it engaged in multiple rounds of discovery, analyzed both the Company's filing, as well as the discovery responses provided by the Company and other parties, the testimony and information of other parties, as well as the advice and counsel of our expert witnesses. Through this analysis the OCA developed its positions in this case, and its decision to support this settlement as it is in the public interest.

II. TERMS AND CONDITIONS OF THE SETTLEMENT

A. General

At the evidentiary hearing on October 1, 2024, the parties informed the ALJs that a non-unanimous settlement in principle was reached between the OCA, UGI, and OSBA. The OCA submitted a Main Brief on October 15, 2024, regarding the litigated issues in this proceeding. Under the Settlement, the parties agree that the Settlement terms, as modified by the Settlement, include and/or address all of the required elements of Section 2807 of the Public Utility Code, the Commission's regulations, and the Commission's policies for a Default Service Plan. Settlement ¶ 35. For the reasons stated below, the OCA submits that the non-unanimous settlement is supported by substantial evidence in the records as is in the public interest and should be approved.

B. Procurement

UGI proposed a 48-month plan to cover the period from June 1, 2025 through May 31, 2029. OCA St. 1 at 5. UGI proposed to use a competitive Request for Proposals (RFP) process to acquire a series of fixed-price, full-requirement (FPFR) contracts and energy blocks to provide generation service for the residential and small commercial default service load. *Id.*[1]

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

[1] The Company 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. OCA St. 1 at 5.

the seller's cost to satisfy its supply obligation may change. OCA St. 1SR at 2. The 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). *Id.* at 2-3. FPFR contract suppliers are exposed to the volumetric risk of uncertain load responsibility while default service customers are insulated from this risk. *Id.* at 3.

An around-the-clock (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). OCA St. 1SR at 3. 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. *Id.*

Residential customers are grouped with small commercial customers under UGI's DSP V. OCA St. 1 at 6. The Company proposed the base of the GSR-1 portfolio to consist of 20-megawatt (MW) ATC block supply (procured annually in 24-month duration contracts with 12-month overlap between two subsequent contracts). *Id.* The Company estimated that each 10-MW ATC block will represent approximately 12 percent load share for GSR-1 related product procurement. *Id.* The remaining power supply 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. *Id.* The FPFR contracts will be procured through RFPs every six months. *Id.*

UGI's 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. OCA St. 1 at 6. The laddering proposed by UGI would have resulted in half of the approximately 76 percent of the portfolio consisting of the 12-month FPFR contracts being replaced every six months. *Id.* The remaining 24 percent of the power supply would be provided through 24-month ATC blocks (20 MW combined in steady-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). *Id.* at 6-7.

UGI proposed 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. OCA St. 1 at 7. The FPFR contract suppliers would bid a dollar-per-MWh price to supply all generation products required to serve their share of load (after the block energy and Allegheny supply offsets) – energy, capacity, ancillary services, and required AECs. *Id.* at 7-8. The FPFR contract price would be fixed for the 12-month contract period. *Id.* at 8. Over the 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 EGS, growth (or decline) in the number of residential and small commercial customers, and weather conditions. *Id.* Under UGI's proposed approach, wholesale FPFR suppliers would be exposed to the volumetric risk of uncertain load responsibility while UGI and its residential and commercial default service customers are insulated from this risk. *Id.*

OCA witness Ogur recommended that residential and small commercial default service supply portfolio consist of 100 percent 24-month 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. OCA St. 1 at 4.

Using 24-month FPFR contracts is fairly common among Pennsylvania's EDCs. For example, Duquesne Light Company's (Duquesne's) residential portfolio consists 50 percent of 12-month FPFR contracts and 50 percent 24-month FPFR contracts. OCA St. 1 at 14. 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. OCA St. 1 at 14. 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. *Id.* 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. *Id.* In its plan for the next default 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. *Id.* at 13-14. Citizens' and Wellsboro currently rely 100 percent on a 48-month FPFR contract with indexed, laddered, energy pricing. *Id.* at 14.

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. The following table 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:

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%

OCA St. 1 at 15. UGI has the second highest volatility for default service rates in the Commonwealth. *Id.*

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. OCA witness Ogur testified that 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. OCA St. 1 at 15. Dr. Ogur further testified that the net effect of these two countervailing forces may not increase UGI's GSR-1 PTC stability much, if at all. *Id.* UGI can deliver better rate stability than this for its residential and small commercial default service customers. *Id.*

Under the Settlement, UGI will procure a 10 MW around-the-clock ATC block tranche with a five-year term. UGI will procure another 10 MW around-the-clock ATC block tranche with a two-year term on a rolling basis through the term of DSP V and into the term of DSP VI. Settlement ¶ 29. UGI's remaining proposed procurement methodologies for GSR-1 and GSR-2 customers as set forth in UGI's Petition for Approval of a Default Service Plan for the period of June 1, 2025 through May 31, 2029 and in UGI Electric St. No. 2, the Direct Testimony of James M. Rouland, pages 12-23, are approved as filed. *Id.* The bid documents appended to UGI St. No. 2 as Exhibits JMR-4 through JMR-10 are also approved, with the changes to implement the above modification. *Id.*

The procurement plan put forth in the Settlement is in the public interest and represents a reasonable compromise of the parties in this proceeding. It is expected to result in greater rate stability than would have been present under UGI's proposal. The OCA supports the Settlement because it ensures reliable electricity supply and follows an established contract duration strategy for load supply contracts. This balance of rate stability with reflectiveness is a benefit because it protects consumers from the shock of price fluctuations. As such, these settlement provisions should be adopted by the Commission as there is sufficient and substantial evidence in the record to support a laddered approach proposed by the settlement.

C. Revenue Allocation Factors

As a condition of settlement in UGI's DSP IV proceeding, UGI agreed to file a procurement study in its next DSP filing. *See* UGI Exh. JRT-2, App. A at 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, 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. OCA St. 1 at 24.

The authors of the procurement study did not make specific recommendations. OCA St. 1 at 24. Instead, 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. *Id.* That cost allocation approach is set by determining the Energy Cost (EC) rate, 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. *Id.*

In response to the procurement study, 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. OCA St. 1 at 24-25.

OCA's witness Ogur disagreed with UGI's proposal and opined that the procurement study should not be relied upon to set an EC rate for residential customers that is 10% higher than the EC rate for non-residential GSR-1 customers. The methodology and assumptions of the procurement study are flawed as it 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. OCA St. 1 at 25. Capacity and transmission charges are incurred based on measures of peak load. *Id.* Residential customers typically have slightly lower ratio of average load to peak load than small non-residential customers. *Id.* As such, residential customers have slightly higher capacity and transmission costs than small non-residential customers. *Id.* Residential and small non-residential customers also have different usage patterns by time of day or season. *Id.* at 25-26. Hourly wholesale electricity prices in PJM's spot markets vary substantially from hour to hour based on a number of factors. *Id.* at 26. 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. *Id.*

The residential and non-residential GSR-1 relative cost factors of 1.02 and 0.93, respectively, as reported in the procurement study, should not be relied upon to arbitrarily increase the EC rate to residential customers and lower the EC rate for non-residential GSR-1 customers. OCA St. 1 at 25. The procurement study biases the hypothetical cost of serving residential customers relative to the hypothetical cost of serving non-residential GSR-1 customers. *Id.*

The authors of the procurement study did not directly account for the cost of the switching risk. OCA St. 1 at 26. 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. *Id.* They estimate a category they refer to as "other costs," defined as the difference between the FPFR auction price and the authors' estimation of energy, capacity, and transmission costs for PECO's FPFR auctions conducted separately for residential and small commercial customers between 2017 and 2022. *Id.* 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." *Id.*

This methodology is flawed because "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. OCA St. 1 at 27. OCA witness Ogur testified that the authors of the Procurement Study could easily have directly estimated most of these elements (e.g., AECs, PJM ancillary services and other line items billed directly by PJM) which were instead thrown into the "other costs" bucket. OCA St. 1 at 27-28. Moreover, the procurement study merely estimates relative levels of "other costs" for one EDC's residential and small commercial FPFR contracts, and then assumes the same ratio for another EDC's (i.e., UGI's) residential and small commercial FPFR contracts. *Id.* at 28.

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. OCA St. 1 at 28. Dr. Ogur testified that ignoring switching characteristics amounts to neglecting a major component of the risk premium. *Id.* 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. *Id.*

As shown in the below table, UGI's residential customer shopping percentage is negligible, and it has consistently been negligible for the last eight years:

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/				

OCA St. 1 at 30-32.

From a supplier's perspective, UGI's residential default service customers would have a negligible switching risk. OCA St. 1 at 30. Moreover, UGI's non-residential GSR-1 customers have much higher shopping rates than UGI's residential customers. *Id.* at 31. The variability of the EGS shopping rates of UGI's non-residential GSR-1 customers is also high. *Id.* Among the four groups reviewed in the procurement study (UGI residential, UGI small commercial, PECO residential, and PECO small commercial customers), UGI's small commercial customers by far have the highest shopping rate volatility as measured by relative standard deviation. *Id.* The obvious conclusion from these comparisons is that UGI's non-residential GSR-1 customers constitutes a much larger switching risk than UGI's residential customers for an FPFR supplier. *Id.*

The above table invalidates the methodology and assumptions present in the procurement study in the estimation of an "other costs" differential or ratio between UGI's residential and non-residential customers. OCA St. 1 at 31. 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. *Id.* Such an assumption is unreasonable. 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. *Id.* at 31-32. 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. *Id.* at 32.

UGI acknowledged 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. OCA St. 1SR at 17. UGI's 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, 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. *Id.*

Under the Settlement, UGI Electric will continue to procure supplies for GSR-1 residential and non-residential customers on a combined basis. Settlement ¶ 30. For the DSP V period, the Company will apply rate allocation factors of 1.01 for residential customers and 0.97 for small commercial customers. *Id.* This is a compromise from their initial litigation position. The allocation factors will expire on May 31, 2029 at the end of DSP V and will not continue into the next DSP period. *Id.* These provisions do not prevent any party from proposing, or waiving their right to propose, rate allocation factors in DSP VI. *Id.*

There is substantial evidence in favor of the OCA's position to not apply rate allocation factors, however, the OCA agreed to relatively small revenue allocation factors in the interest of compromise in furtherance of settlement with all parties including the OSBA. Importantly, these rate allocation factors will expire at the end of DSP V and will not continue into the next DSP period, which helps ensure that they do not continue indefinitely. These settlement provisions, on the context of the whole of the settlement, are in the public interest and should be adopted by the Commission.

D. Load Cap

UGI proposed a 50 percent load cap (or tranche cap) for GSR-1 FPFR procurements. OCA St. 1 at 21. OCA witness Ogur recommended a 75 percent load cap for UGI's default service portfolio for FPFR tranches. OCA St. 1SR at 14. Dr. Ogur testified that, if 50 percent is selected as the load cap under the OCA's 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. OCA St. 1 at 21. Setting the load cap at 75 percent would restrict a supplier to sit out at most one solicitation in four semi-annual solicitations. *Id.* Since UGI expressed concern about, and wants to maximize, supplier participation, Dr. Ogur testified that 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. *Id.*

Under the Settlement, UGI Electric's 50 percent load cap proposal applicable to FPFR tranches shall be conditional and apply prospectively to future FPFR solicitations after the point where UGI receives at least three independent bids for a FPFR solicitation (i.e., not apply to such initial solicitation where three bids are received but thereafter conditionally apply to all future FPFR solicitations). Settlement ¶ 31. Absent three or more bids, the load cap shall not apply in such future solicitations. *Id.*

The Settlement adequately resolves the OCA's concerns. These settlement provisions represent a reasonable compromise on the load cap issue that helps promote competition through diverse bids and reduces counterparty risk by limiting exposure to a single wholesale supplier. The load cap provisions agreed upon by the settling parties are in the public interest and should be approved by the Commission.

E. Reconciliation

Following his review of UGI's initial filing, OCA witness Ogur noted that there was contradictory information regarding how often UGI would change its reconciliation rate. OCA St. 1 at 9-10. UGI's direct testimony indicated 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. UGI St. 3 at 12; OCA St. 1 at 9-10. However, UGI's direct testimony also suggested that that over- or under-collections over a six-month period would necessarily be amortized over a subsequent six-month period. UGI St. 3 at 14; OCA St. 1 at 10. OCA witness Ogur requested that UGI clarify its proposal. OCA St. 1 at 10. Additionally, Dr. Ogur recommended that the Commission adopt a 12-month amortization period for over- or under-collection balances reconciled over a six-month period 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. *Id.*

Following its review of the OCA's direct testimony, UGI agreed with OCA witness Ogur's recommendation and noted that UGI would make the appropriate tariff updates. UGI St. 2R at 14-15. Under the Settlement, for the GSR-1 customer group, UGI Electric will utilize a 12-month amortization period for over- or under-collections balances reconciled for each six-month period. Settlement ¶ 32. This Settlement provision adopts the OCA's recommendation and is in the public interest as it avoids 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.

E. GSR-1/GSR-2 Customer Classification.

GSR-1/GSR-2 customer classification is the subject of litigation in this proceeding and is the focus of the OCA's briefs. Under the Settlement, UGI Electric's proposal to classify GSR-1 and GSR-2 customers based upon their supply peak load impact is approved. These provisions are in the public interest as there is no basis for the position of Penn Renewables who opposed the settlement. The OCA incorporates its arguments from its briefs in support of the Settlement.

III. THE SETTLEMENT IS IN PUBLIC INTEREST

The OCA submits that the Settlement is supported by substantial evidence and is in the public interest for the reasons outlined above. This Settlement represents a balance of the signatory parties and provides crucial protections and benefits for consumers. Without this

Settlement, the parties would be forced to continue costly and burdensome litigation, where results are unpredictable and benefits less certain. The Settlement ensures that UGI will meet its statutory responsibilities to procure a default service portfolio that is designed to ensure service at least cost over time. In its whole, all of these benefits, especially when weighed against the risks and costs of litigation, demonstrate that this proposed Settlement is in the public interest.

Respectfully submitted,

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Dated: October 22, 2024

APPENDIX D

Statement In Support

Office of Small Business Advocate

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.	:	

STATEMENT OF
THE OFFICE OF SMALL BUSINESS ADVOCATE
IN SUPPORT OF THE
JOINT PETITION FOR APPROVAL OF
NON-UNANIMOUS SETTLEMENT

I. Introduction

The Small Business Advocate is authorized and directed to represent the interests of the small business consumers of utility services in the Commonwealth of Pennsylvania under the provisions of the Small Business Advocate Act, Act 181 of 1988, 73 P.S. §§ 399.41 - 399.50. Pursuant to that statutory authority, the Office of Small Business Advocate ("OSBA") filed an Answer and Notice of Intervention, in the above-captioned proceeding, on June 25, 2024, in response to the Petition of UGI Utilities, Inc. – Electric Division ("UGI-E" or the "Company") for Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029 ("Petition"), that was filed with the Pennsylvania Public Utility Commission ("Commission") on May 31, 2024.

The OSBA participated in the negotiations that led to the proposed settlement and is a signatory to the Joint Petition for Approval of Non-Unanimous Settlement ("*Joint Petition*"). The OSBA submits this statement in support of the *Joint Petition*.

II. The Commission's Policy on Settlements

Section 5.231(a) of the Commission's regulations, 52 Pa. Code § 5.231(a) (Formal Proceedings; Hearings; Settlement and Stipulations; Offers of Settlement) states, as follows:

> It is the policy of the Commission to encourage settlements.

Similarly, Section 69.401 of the Commission's regulations, 52 Pa. Code § 69.104 (Settlement Guidelines and Procedures for Major Rate Cases – Statement of Policy; General) states, as follows:

> In the Commission's judgment, the results achieved from a negotiated settlement or stipulation, or both, in which the interested parties have had an opportunity to participate are often preferable to those achieved at the conclusion of a fully litigated proceeding.

III. Procurement of Electric Supply

The *Joint Petition* proposes to retain UGI-E's current default service rate class groups, GSR-1 and GSR-2.[1] GSR-1 includes residential and non-residential customers with maximum peak demand up to 100 kW, while GSR-2 includes non-residential customers with maximum demand above 100 kW.[2]

The *Joint Petition* proposes to change how UGI-E will procure its electric supply. Specifically, the *Joint Petition* proposes that UGI-E will procure a 10 MW around-the-clock block tranche with a 5-year term. In addition, UGI-E will procure another 10 MW around-the-clock block tranche with a 2-year term on a rolling basis throughout the term of DSP V and into the term of DSP VI.[3]

This proposed methodology is designed to address the results that UGI-E was obtaining

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[1] *Joint Petition*, Paragraph 29.

[2] *Joint Petition*, Paragraph 34.

[3] *Joint Petition*, Paragraph 29.

with inconsistent supplier participation in DSP IV for both 12-month and 24-month full requirements load following ("FRLF") contracts. Apparently, part of the problem was due to variable block sizing that changed throughout the course of the contracts.

Finally, the *Joint Petition* proposes a 50 percent load cap applicable to fixed-price full-requirements ("FPFR") tranches. Such load caps will be conditional and apply prospectively to future FPFR solicitations after the point where UGI-E receives at least three independent bids for an FPFR solicitation. If three or more bids do not materialize, the load cap shall not apply in such future solicitations.[4]

The OSBA supports the procurement changes proposed by the *Joint Petition*. The proposals should provide the Company's small business customers with reasonable and stable electricity pricing.

IV. <u>Rate Differentials</u>

The Settlement of the DSP IV proceeding at Docket No. P-2020-3019907 required UGI-E to file a study by June 30, 2022, evaluating the relative cost of default service supplies for the 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-E.[5]

[4] *Joint Petition*, Paragraph 31.

[5] OSBA Statement No. 1, at 7.

NorthBridge's study determined that the cost of UGI-E's residential GSR-1 default service supply is about 2 percent *higher* than the composite GSR-1 default service supply cost. The study also found that the cost of UGI-E's non-residential GSR-1 default service supply is about 6 to 7 percent *lower* than the composite GSR-1 default service supply cost.

The *Joint Petition* proposes to follow these results. Specifically, the *Joint Petition* will require the Company to apply rate allocation factors of 1.01 for residential customers and 0.97 for small commercial customers. The allocation factors will expire on May 31, 2029, at the end of DSP V.

As the *Joint Petition* conforms to the findings of the NorthBridge study, the OSBA supports the proposed rate allocation factors as a just and reasonable solution to this issue.

V. **Conclusion**

For the reasons set forth in the *Joint Petition*, as well as the additional factors that are enumerated in this statement, the OSBA supports the proposed *Joint Petition* and respectfully requests that the ALJ and the Commission approve the *Joint Petition* in its entirety.

Respectfully submitted,

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