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May 31, 2024

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building, 2nd Fl
400 North Street
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division For Approval of a Default Service Plan (DSP V) for the Period of June 1, 2025 through May 31, 2029
Docket No. P-2024_________

Dear Secretary Chiavetta:

Enclosed for filing on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company"), please find the *Petition of UGI Utilities, Inc. – Electric Division For Approval of Default Service Plan (DSP V) For The Period June 1, 2025 through May 31, 2029* ("Default Service Plan"). To facilitate approval, the Company has filed its direct testimony with the Default Service Plan.

The filing consists of the following documents:

- Petition
- Appendix A – Electric Service Proforma Redline Tariff;
- Appendix B – UGI Electric Statement No. 1 of Jesse Tyahla with Exhibits JRT-1 and JRT-2
- Appendix C – UGI Electric Statement No. 2 of James Rouland with Exhibits JMR-1 through JMR-10
- Appendix D – UGI Electric Statement No. 3 of Tracy Hazenstab with Exhibits TAH-1 and TAH-2

Please enter the appearance of the following attorneys on behalf of the Company in this proceeding:

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Please send copies of all documents and communications in this proceeding to the counsel listed above.

As indicated on the attached Certificate of Service, UGI Electric is serving this Petition of the Bureau of Investigation & Enforcement, the Office of Consumer Advocate, the Office of Small Business Advocate, and PJM Interconnection, LLC. Duquesne Light is also serving all active parties in the Company's last default service proceeding, *Petition of UGI for Approval of Default Service Plan For The Period June 1, 2021 Through May 31, 2025*, at Docket Nos. P-2020-3019907 and G-2020-3019908.

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

Respectfully submitted,

Anthony D. Kanagy

Anthony D. Kanagy

ADK/kls
Attachment

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

CERTIFICATE OF SERVICE

I hereby certify that I have, this 31st day of May 2024, served a true and correct copy of the foregoing document in the manner and upon the persons listed below in accordance with requirements of 52 Pa. Code § 1.54 (relating to service by a participant):

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Date: May 31, 2024

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

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PETITION OF UGI UTILITIES, INC. – ELECTRIC DIVISION FOR APPROVAL OF A DEFAULT SERVICE PLAN

TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION:

Pursuant to Section 2807 of the Pennsylvania Public Utility Code, 66 Pa. C.S. § 2807, and the regulations of the Pennsylvania Public Utility Commission ("Commission" or "PUC") at 52 Pa. Code §§ 54.181-54.190 ("Default Service Regulations"), UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") hereby requests approval of its fifth Default Service Plan ("DSP V" or the "Plan"). The Plan establishes the terms and conditions under which the Company will acquire default service supplies, including Alternative Energy Portfolio Standards ("AEPS") credits, from June 1, 2025, through May 31, 2029 ("DSP V Term"). It employs a prudent mix of electric supplies (e.g., spot market purchases, short-term contracts, and long-term contracts) obtained through competitive bid solicitation processes (e.g., auctions, requests for proposals and/or bilateral agreements). Consequently, the Company's default service customers will receive adequate and reliable service at the least cost over time.[1] Additionally, UGI Electric requests that the Commission:

[1] This aligns with the Commission's goal for the Default Service Regulations - to ensure that each default service provider delivers adequate and reliable service at the least cost over time (as stated in 52 Pa. Code § 69.1802).

1. Approve potential affiliated interest transactions associated with DSP V pursuant to Section 2102 of the Public Utility Code, 66 Pa. C.S § 2102; and

2. Approve the Company's DSP V Plan no later than the Commission's last public meeting in January 2025, if possible, to provide sufficient time to implement the procurement strategy in DSP V prior to the expiration of the current DSP IV plan on May 31, 2025, for purchases beginning June 1, 2025 without the need for modification of procurement timing.

Through its DSP V Petition, the Company will (1) procure a competitive mix of default service supplies through load-following, block and spot market purchases, and related AEPS credits over the 4-year DSP V Term (i.e., 2025-2029); (2) implement a procurement schedule designed to obtain these supplies at the least cost; (3) issue Requests for Proposals ("RFPs") seeking default supply in accordance with the agreements and forms included with this Petition; (4) adopt a contingency plan[2] that addresses any procurement target shortfalls; (5) recover all incurred default service costs on a full and current basis through a specified default service rate design; (6) adopt revised tariff rules clarifying the application of GSR-1 and GSR-2 default service rate classifications; and (7) continue the retail enhancement programs adopted in DSP IV.

As noted herein, the Company is clarifying the GSR-1 and GSR-2 rate groupings to classify customers according to their supply peak load impact. This approach will better align larger net-metering customer-generators with larger customers that have similar grid impacts.

[2] A default service plan must contain contingency plans to address situations where a wholesale generation supplier does not meet its contractual obligation to provide electric supply to default service providers. 52 Pa. Code § 54.185(d)(5).

I. INTRODUCTION

1. UGI Electric is a "public utility", an "electric distribution company" ("EDC") and a "default service provider" as defined in Sections 102 and 2803 of the Public Utility Code, 66 Pa. C.S. §§ 102, 2803.

2. UGI Electric provides electric distribution service to approximately 62,000 customers in portions of two northeastern Pennsylvania counties (Luzerne and Wyoming Counties), and since the expiration of its generation rate cap in 2002, has served as the default service provider for its electric distribution system.

3. UGI Electric's address is UGI Utilities, Inc., 1 UGI Drive, Denver, PA 17517.

4. UGI Electric's attorneys are:

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II. LEGAL AUTHORITIES

A. STATUTORY REQUIREMENTS

5. On December 3, 1996, Governor Tom Ridge signed into law the Electricity Generation Customer Choice and Competition Act ("Competition Act"). The Competition Act revised the Public Utility Code, 66 Pa. C.S. §§ 101, *et seq.*, by, inter alia, adding Chapter 28, relating to restructuring of the electric utility industry. Chapter 28 provided for an orderly transition of the Pennsylvania electric industry from a vertically integrated monopoly to a structure which would support the development of a competitive retail electric generation market. The ultimate goal was to permit all Pennsylvania retail electric customers to have direct access to a competitive generation market, while simultaneously enjoying the continued reliability, and safety of existing transmission and distribution services. The Competition Act became effective on January 1, 1997.

6. The Alternative Energy Portfolio Standards Act of 2004, P.L. 1672, No. 213, ("AEPS Act") was signed into law on November 30, 2004. 73 P.S. §§ 1648.1, *et seq*. The AEPS Act, which took effect on February 28, 2005, established an alternative energy portfolio standard for Pennsylvania. Generally, the Act requires that an annually increasing percentage of electricity sold to retail customers in Pennsylvania by EDCs and electric generation suppliers ("EGSs") be derived from alternative energy resources.

7. On October 15, 2008, Governor Edward Rendell signed House Bill 2200, Act 129, into law. Act 129 became effective on November 14, 2008. It has several goals including reducing energy consumption and demand. It also revised the default service requirements contained in Chapter 28 of the Public Utility Code (i.e., the Competition Act). Act 129 of 2008, P.L. 1592.

8. As such, Section 2807(e) of the Competition Act now requires each EDC to provide default service to retail customers within its certificated territory when either a chosen EGS does not do so or when customers otherwise do not choose to receive service from an EGS. Pursuant to Act 129, electric power shall be procured through competitive procurement processes and shall include one or more of the following: (1) auctions; (2) requests for proposals; or (3) bilateral agreements. 66 Pa. C.S. § 2807(e)(3.1). The electric power that is procured shall include a prudent mix of: (1) spot market purchases; (2) short-term contracts; and (3) long-term purchase contracts of more than 4 and not more than 20 years. 66 Pa. C.S. § 2807(e)(3.2). In addition, 66 Pa. C.S. § 2807(e)(3.3) made it clear that all energy purchased by a default service provider must be competitively procured, including AEPS credits associated with energy generated from qualifying alternative resources at the levels specified in the AEPS Act.

9. The "prudent mix" of contracts shall be designed to ensure: (1) adequate and reliable service; (2) the least cost to customers over time; and (3) compliance with the procurement methodologies described above, i.e., through auctions, RFPs; or bilateral agreements. 66 Pa. C.S. § 2807(e)(3.1).

10. Regarding process, default service providers must file a plan for competitive procurement with the Commission and obtain Commission approval of the plan considering certain factors and standards contained in Section 2807(e) before competitive procurements may be implemented.

11. When evaluating a default service plan, the Commission must consider the EDC's obligation to provide adequate and reliable service to the customers. The Commission also must determine that the EDC has obtained a prudent mix of contracts at

the least cost on a long-term, short-term, and spot market basis. The Commission is required to make specific findings when reviewing DSPs: (1) the DSP includes prudent steps necessary to negotiate favorable generation supply contracts; (2) the DSP includes prudent steps necessary to obtain least cost generation contracts on a long-term, short-term and spot market basis; and (3) neither the default service provider nor its affiliated interest has withheld generation supply from the market as a matter of federal law. 66 Pa. C.S. § 2807(e)(3.7).

12. Further, Act 129 revised the Competition Act giving default service providers a right to recover default service costs pursuant to a reconcilable automatic adjustment clause. It also stated that residential and small commercial customers rates cannot change more frequently than quarterly. 66 Pa. C.S. § 2807(e)(7).

13. To implement the statutory requirements of the Competition Act, the AEPS Act and Act 129, the Commission adopted Default Service Regulations at 52 Pa. Code §§ 54.181-54.190, a Default Electric Service ("DES") Policy Statement at 52 Pa. Code §§ 69.1801-69.1817 ("DES Policy Statement") and provided guidance for default service plans through various Electric Retail Markets Investigation ("RMI") Orders at Docket No. I-2011-2237952.

B. DEFAULT SERVICE REGULATIONS

14. The Commission's Default Service Regulations set forth the obligations of EDCs to serve as default service providers. Section 54.183 states that the incumbent EDC

shall serve as the default service provider until and unless an alternative provider is approved by the Commission.[3]

15. Sections 54.184 through 54.186 set forth the framework through which customers have access to generation supply. Section 54.184 states that the default service provider, acting in the default service function, shall serve customers when either a chosen EGS does not do so or when customers otherwise do not choose to receive service from an EGS (similar to the requirements set forth in 66 Pa. C.S § 2807(e)(3.1)). Additionally, a default service provider must file a DSP with the Commission no later than 12 months prior to the conclusion of the currently effective program (per 52 Pa. Code § 54.185(a)). After the first DSP, the term of subsequent programs shall be determined by the Commission. 52 Pa. Code § 54.185(d).[4]

16. Section 54.186 states what DSPs must accomplish and the standards they must follow. More specifically, DSPs must acquire generation supply at the least cost to customers over time (similar to the requirements of 66 Pa. C.S. § 2807(e)(3.3)(ii)). According to 52 Pa. Code § 54.186 (b)(1)(i)-(iii), DSPs also must include procurement plans, which acquire a prudent mix of resources, including spot market purchases, short-term contracts, and long-term contracts (like the requirements set forth in 66 Pa. C.S. § 2807(e)(3.2)(i)-(iii)). As specified in 52 Pa. Code § 54.186(b)(5), DSPs must obtain electric generation supplies through competitive bid solicitation processes (akin to the requirements set forth in 66 Pa. C.S. § 2807(e)(3.1)). The specific competitive bid

[3] The Commission confirmed this much in its *Investigation of Pennsylvania's Retail Market: End State Default Service*, Docket No. I-2011-2237952 (Final Order entered February 15, 2013). Based on its review of industry feedback in Docket No. I-2011-2237952, the Commission was "persuaded to adopt [its] initial proposal to retain the EDC in the DSP role." *Id.* at 20.

[4] The DES Policy Statement at 52 Pa. Code § 69.1804 suggests using a DSP term of two to three years, unless otherwise approved by the Commission.

processes that default service providers must adhere to are detailed in 52 Pa. Code § 54.186(c).

17. Additionally, Section 54.187 specifies the means by which EDCs may recover costs for engaging in the default service function. According to 52 Pa. Code § 54.187(b), costs incurred in providing default service shall be recovered on a full and current basis through a Section 1307 reconcilable adjustment clause, including costs for complying with the AEPS Act as stated in 52 Pa. Code § 54.187(f). These regulations are similar to the statutory requirements set forth in 66 Pa. C.S. § 2807(e)(3.9).

C. THE COMMISSION'S DES POLICY STATEMENT

18. The Commission's DES Policy Statement (at 52 Pa. Code §§ 69.1801 – 69.1817) became effective on September 15, 2007. As specified in Section 69.1802, the goal of the Commission's default service regulations is the provision of adequate and reliable service to default service customers at the least cost over time. The DES Policy Statement's guidelines provide the flexibility needed for default service providers to achieve this goal through their DSPs.

19. According to 52 Pa. Code § 69.1805, default service providers have the flexibility to seek a prudent mix of supply-side and demand-side resources (such as long-term, short-term, staggered-term and spot market purchases) to minimize contracting for supply at times of peak prices.

20. Regarding the cost of default service, Section 69.1808 states that the EDC's price to compare ("PTC") should recover all generation and transmission costs including: wholesale energy, capacity, ancillary, Retail Transmission Organization ("RTO") administrative and transmission costs, congestion costs, supply management costs, administrative costs, applicable taxes and AEPS compliance costs.

21. Per Section 69.1809, default service rates and the PTC may not be adjusted more frequently than quarterly to reflect changes in wholesale energy and related costs and to reconcile over- and under-collections. Default service costs and revenues should be reconciled as part of the PTC adjustment process.

22. In addition, Section 69.1815 requests the inclusion of customer referral programs[5] in DSPs.

D. THE COMMISSION'S ELECTRIC RMI ORDERS

23. Beginning with its Order in the Investigation of Pennsylvania's Retail Electricity Market at Docket No. I-2011-2237952, which was entered on April 29, 2011, the Commission initiated an Electric RMI proceeding to address and resolve retail market issues identified by the Commission. In the Electric RMI proceeding, the Commission issued a number of Orders that impacted DSPs.[6]

24. In its December 16, 2011 Electric RMI Order, the Commission confirmed that EDCs should: 1) limit or eliminate short-term contracts that extend beyond the end of the DSP period; and 2) limit the proportion of long-term contracts and consider using already-existing ones. (December 16, 2011 RMI Order at 19). The Commission also reiterated that it will not prescribe specific contract durations for default service procurements. (*Id*. at 19-20). The December 16, 2011 RMI Order further permitted EDCs to use a laddering approach such that supply purchases occur at different times and with

[5] Infra at pp. 11-12.

[6] *See Investigation of Pennsylvania's Retail Electricity Market: Recommendations Regarding Upcoming Default Service Plans*, Docket No. I-2011-2237952 (Final Order entered December 16, 2011) ("December 16, 2011 RMI Order"); *Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan*, Docket No. I-2011-2237952 (Final Order entered March 2, 2012) ("March 2, 2012 RMI Order"); *Investigation of Pennsylvania's Retail Market: End State Default Service*, Docket No. I-2011-2237952 (Order entered February 15, 2013) ("February 15, 2013 RMI Order") (collectively "Electric RMI Orders").

overlapping delivery periods. (*Id*. at 20-21). Here, the Commission further clarified that EDCs do not need long-term contracts for AEPS credit solicitations.

25. The Commission entered a Tentative Order in Docket No. I-2011-2237952 on November 8, 2012.[7] It requested that EDCs offer hourly Locational Marginal Pricing ("LMP") to medium and large commercial and industrial customers (with demands of 100 kW or greater). (November 8, 2012 Tentative Order at 16-17).[8]

26. Additionally, in the November 8, 2012 Tentative Order, the Commission proposed fixed, quarterly, PTCs for residential and small commercial customers. The Commission envisioned the enactment of quarterly auctions to procure all default service load for these residential customers through tranches of full requirements, load-following contracts. (*Id*.). Similarly, the auctions would occur one to two months before the beginning of the delivery date for the upcoming quarter. (*Id*.).

27. In its March 2, 2012 RMI Order, the Commission determined that DSPs should include two types of Customer Referral Programs: New/Moving Customer and Standard Offer. (March 2, 2012 RMI Order at 13-33). New/Moving Customer Referral Programs provide residential and small commercial customers with basic information on shopping during calls to initiate service and calls to move service to a new address. (*Id*. at 17-18).

[7] *See Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952 (Tentative Order entered November 8, 2012) ("November 8, 2012 Tentative Order).

[8] The Commission explained the reasoning behind the 100 kW threshold in its October 14, 2021 Tentative Order at Docket No. I-2011-2237952, stating that "[c]urrently, a significant level of electric shopping occurs for medium sized commercial and industrial customers, generally those customers with demand greater than 100 kW." (October 14, 2011 Tentative Order at 8). "This robust level of shopping by medium commercial and industrial customers may result in a higher risk premium being priced into default service, which would be passed onto small commercial and industrial customers." (Id.).

28. In its December 16, 2011 RMI Order, the Commission stated that it would consider DSPs with quarterly, semi-annual, or annual reconciliation periods. (December 16, 2011 RMI Order at 54). The Commission also instructed EDCs to include clear descriptions of how quarterly changes in supply charges would be calculated, adjusted, reconciled, and allocated among default service rate classes. (*Id.*).

29. As explained herein, UGI Electric's Petition and proposed DSP V are designed in accordance with the Commission's DES regulations, DES Policy Statement, and Electric RMI Orders.

III. <u>UGI ELECTRIC'S PROPOSED PLAN – DSP V</u>

A. INTRODUCTION

30. In this proceeding, the Company seeks to implement its DSP V Plan during the four-year period between June 1, 2025 and May 31, 2029. The Commission's DES Policy Statement (at 52 Pa. Code § 69.1804) suggests using a DSP term of two to three years, unless otherwise approved by the Commission. The Commission approved a four-year term for the Company's DSP III Plan and DSP IV Plan. In addition, the Commission has approved four-year default service plans for all of the large EDCs in Pennsylvania, including PPL Electric Utilities Corporation, Duquesne Light Company, the FirstEnergy Companies (now FirstEnergy Pennsylvania Electric Company), and PECO Energy Company. UGI Electric seeks the same allowance to implement its DSP V over a four-year term.

31. In accordance with 52 Pa. Code § 54.185(e)(1), the Company's DSP V includes a procurement plan, which identifies a supply acquisition strategy for use during the proposed plan period (June 1, 2025 through May 31, 2029). The DSP V Plan also

identifies the means by which the Company will satisfy the minimum portfolio requirements set forth in the AEPS Act.

32. The Company developed its proposed DSP V Plan to be similar to the procurement plans utilized by other EDCs in Pennsylvania, with a general movement from the DSP IV plan in a manner to optimize procurement activities. The Company has identified that other EDCs rely almost entirely on a laddered mix of fix priced full requirements ("FPFR") contracts for their residential and small commercial customers, with some including longer term block purchases. UGI Electric intends to follow a similar approach in its DSP V procurement plan for GSR-1 customers.

33. Historically, the Company has relied on a combination of block and full requirements contracts, as well as some spot purchases, to procure supplies for GSR-1 customers. As explained by UGI Electric witness James M. Rouland, UGI Electric Statement No. 2, under the DSP IV Plan, the Company experienced limited bidder participation and higher risk premiums for its full requirements contracts. For DSP V, the Company is taking significant steps to reduce the risk for its FPFR contracts, both in how it is adjusting its product mix and in how the RFP and contract terms are being adjusted. The Company also determined that increased supplier risk premiums are due, in part, to the inclusion of non-market-based transmission costs. Therefore, UGI Electric is proposing to remove those costs from its full requirements contracts, similar to the treatment of these costs by other EDCs. Additionally, the Company is proposing to provide full requirements suppliers with guidance on PJM Interconnection LLC ("PJM") capacity pricing in the event such prices are not available or final. This guidance will allow bidders

to make an informed bid with a defined capacity price, and if the actual capacity price differs from that used in the bid, UGI Electric will settle the difference with the supplier.

34. As discussed in greater detail later in this petition, UGI Electric is proposing changes to its block and full requirements products to reduce risk. The Company is implementing a fixed MW around-the-clock block product which will add price stability to the default service supply mix and limit risk to full requirements suppliers by predefining the block amount. The block product will also replace the 24-month full requirements product from DSP IV. This shift will result in a higher MW amount for the 12-month full requirements products in this plan, providing greater supply and improved stability to suppliers and customers alike. Collectively, these efforts will aid in the reduction of supplier risk, likely improve the attractiveness of full requirements and block product supplies to suppliers, improve competition, and hopefully lower associated premiums.

B. DSP V CUSTOMER RATE CLASSIFICATIONS

35. The Company's default supply acquisition strategy for DSP V will continue to identify customers by GSR-1 and GSR-2 customer groupings, as was done in DSP IV. However, in DSP V, UGI Electric is clarifying that these groupings are determined by the supply peak load impact of the customer, with GSR-1 applying to those customers with a supply peak load impact below 100 kW, and GSR-2 applying to those customers who have a supply peak load impact that is greater than or equal to 100 kW. This approach includes reviewing net metering customer-generators based upon their net supply peak load impact, with resulting separation of portfolio risk management and costs impacts to default service procurement activities. The uniform application of a 100 kW threshold addresses possible small versus medium/large cross-subsidy concerns and provides clarity for all customers.

C. GSR 1 PROCUREMENT STRATEGY FOR DSP V

36. The Company will procure its estimated annual supply for GSR-1 customers through several procurement types: 1) ATC block product Bids; 2) GSR-1 Full Procurement Full Requirements ("FPFR") Load-Following Service Bids; and 3) the long-term arrangement between UGI Electric and the Allegheny Electric Cooperative, Inc. ("Allegheny").[9] Additionally, UGI Electric intends to acquire alternative energy credits in association with certain supply purchasing activity necessary for compliance with state AEPS obligations through a competitive procurement. The Company will also acquire necessary spot energy, capacity and ancillary services through the PJM markets as necessary.

37. Included in Appendix C, the direct testimony of UGI Electric witness James M. Rouland, UGI Electric Exhibit JMR-2 provides an overview of the proposed product procurements and schedule.

38. Since there is a relatively small percentage of overlap in products from DSP IV to DSP V, the Company proposes to procure a majority of the portfolio's supply in Solicitation 1. This is described by Mr. Rouland in UGI Electric St. No. 2. After Solicitation 1, UGI Electric will transition into its steady state procurements for the remainder of DSP V.

1. GSR-1 Block Purchase Bids for DSP V

39. In DSP IV, the Company procured a mix of single-month contracts through ATC and peak block purchase bids. Each bid round, one in Spring and Fall of each Plan

[9] Allegheny has been reselling power procured from New York to UGI Electric pursuant to the *Agreement of Electric Service* ("Allegheny Agreement"), which has been in place since January 5, 2004.

year, sought block supplies to be delivered over 6-month periods in an amount of 25% of the total GSR-1 load needed during each month of the 6-month period. The Company issued RFPs seeking 5x16 energy blocks and 7x24 energy blocks. For each of these block products, the 6-month period was awarded on an individual month basis, with a varying amount of load identified for each of the months in the 6-month period.

40. For DSP V, once in steady-state, the base of the GSR-1 portfolio will consist of 20 MW of around the clock ("ATC") block supply. There will be two staggered tranches of ATC block contracts. Each of the blocks will be for 10 MW of load and will be for a 24-month term.

41. For the first block tranche, a 10 MW ATC block contract will be procured in an auction to be held between January and March 2025 for service beginning June 1, 2025, through May 31, 2027. An additional 10 MW ATC block contract will be procured in an auction to be held between January and March 2027 for service beginning June 1, 2027, through May 31, 2029, which coincides with the end of the DSP V Term.

42. For the second block tranche, a 10 MW ATC block contract will be procured in an auction to be held between January and March 2026 for service beginning June 1, 2026, through May 31, 2028. An additional 10 MW ATC block contract will be procured in an auction to be held between January and March 2028 for service beginning June 1, 2028, through June 1, 3030. This contract will extend past the DSP V Term and will provide rate stability and a transition period for GSR-1 customers as the Company moves into the DSP VI period. The Commission has approved over-hanging contracts (i.e., contracts that extend from one DSP period to the next) for other EDCs in Pennsylvania.

43. By staggering the 24-month ATC 10 MW block contracts, the Company will provide longer term rate stability for GSR-1 customers than is currently provided under the DSP IV plan. Further, as described in the testimony of UGI Electric witness Mr. Rouland, the transition to longer term fixed load block products is expected to improve the marketability of the full requirements contracts by creating a more stable and forecastable load that would be covered by those contracts.

2. GSR-1 Full Requirements Load-Following Service Bids for DSP V

44. In DSP IV, the Company procured a mix of 12-month and 24-month FPFR contracts for approximately 75% of its total default service supply obligation. These contracts had a relatively small MW size, with few bidders participating and higher than desired premiums for these contracts.

45. UGI Electric is aware that all the larger EDCs in Pennsylvania rely primarily on FPFR contracts to provide default supply for residential and small commercial customers. In DSP V, the Company seeks to procure more supply for its GSR-1 customers through FPFR contracts and is taking significant steps to encourage more bidder participation by increasing the total load served by each awarded contract and reducing supplier risks through the fixed block products and by removing non-market-based transmission costs from the pricing. UGI Electric expects that increased competition and reduced risk will reduce the premiums ultimately borne by the Company's GSR-1 customers.

46. In DSP V, once the Company reaches a steady state, it will procure two tranches of 12-month FPFR contracts. Each contract will be for 50% of FPFR supply above the 20 MW ATC block purchases, the Allegheny Agreement purchases discussed

below, and customer-generation purchased by the Company through its net metering program. The 12-month FPFR contracts will be staggered at 6-month intervals. The 12-month FPFR contract for the first tranche will be procured in an auction to be held between January and March 2025 for supply beginning June 1, 2025 through May 31, 2026. New 12-month FPFR contracts will be procured in annual auctions held between the January and March period for service beginning June 1 so that there are continuing 12-month FPFR contracts for the first tranche.

47. For the second FPFR tranche, the Company will procure a 12-month FPFR contract in an auction to be held between July and September 2025 for service beginning December 1, 2025 through November 30, 2026. New 12-month FPFR contracts will be procured in auctions to be held between the July and September period for service beginning December 1 so that there are continuing 12-month FPFR contracts for the second tranche. The procurement methodology is described in more detail in UGI Electric St. No. 2 and accompanying exhibits.

48. The 12-month FPFR contracts for both tranches will overlap to provide rate stability for GSR-1 customers. In addition, the last 12-month FPFR contract for the second tranche will overhang 6 months into the DSP VI period, which also will provide GSR-1 customers with rate stability going into the DSP VI period to avoid a hard stop and hard start between the end of DSP V and the beginning of DSP VI.

49. The Company is proposing to provide a more reliable competitive product for customers through improved supplier participation, defined competitive procurement events, and increased supplier diversity. Improved supplier diversity is achieved through a FPFR tranche cap, limiting the number of suppliers that can be awarded FPFR tranches to

one supplier for a single 12-month tranche. By implementing a fixed MW ATC block product, FPFR suppliers will have pre-defined block terms throughout the course of the contract term, limiting the risk that block supply could rise or fall and therefore impacting the supply amount and associated premiums for that supply. The Company is also providing FPFR suppliers with guidance on PJM capacity pricing in the event such prices are not final, also limiting the supplier risk during bidding and throughout the contract term. Finally, as previously discussed, UGI Electric will pull back NMB costs from FPFR suppliers, again reducing the risk associated with cost components that needlessly increase supplier risk premiums or that make FPFR less desirable.

3. Allegheny Agreement Purchases for DSP V

50. A small portion of the Company's default service load for DSP V will continue to be acquired through the long-term arrangement between UGI Electric and the Allegheny Electric Cooperative, Inc. ("Allegheny") as was done in DSP III and DSP IV. The history of this arrangement can be found in the testimony of Mr. Rouland. In short, Allegheny purchases generation from the Power Authority of the State of New York ("NYPA") in bulk and resells it to various Pennsylvania counterparties (one of which is UGI Electric).[10] During each year of DSP V, Allegheny will provide UGI Electric with an allocated share of hydroelectric power generated in New York and obtained from NYPA. UGI Electric's allocated share is currently set at 2.6409% of the total amount that Allegheny purchases from NYPA and distributes to the various Pennsylvania counterparties under the Agreement. NYPA will likely revise this percentage during the

[10] Allegheny purchases this electric generation from New York through the currently effective *Agreement for the Sale of Saint Lawrence-FDR Project Power and Energy to Allegheny Electric Cooperative, Inc*. (between NYPA and Allegheny).

term of DSP V. Historically, these updates/revisions have been limited in nature. Pursuant to the terms of the Agreement between UGI Electric and Allegheny, the Company will abide by the revised percentages set by NYPA. These procurements will continue to be included as a generation supply source in the Company's DSP V and will be recovered through the Company's GSR-1 rate (Rider B – Generation Supply Service Surcharge) in the same manner as occurred in DSP III and DSP IV.

D. GSR-2 (LMP) PROCUREMENTS FOR DSP V

51. UGI Electric currently has approximately 100 GSR-2 default service customers. These customers have a combined peak load of more than 13.9 MW. For DSP V, the GSR-2 group will consist of customers with a supply peak load impact of 100 kW or greater. This is similar to the customers included in GSR-2 in DSP III and DSP IV, although the Company proposes in this filing to provide greater clarity as to how this rate will be applied for customer-generator accounts.

52. For DSP V, consistent with DSP III and DSP IV, the Company proposes to acquire and apply PJM's real-time hourly market pricing for supply.

53. For these procurements, the Company will be responsible for acquiring any necessary capacity, transmission to UGI Electric's system, ancillary services, congestion management services, AEPS credits and such other services or products as are necessary to provide default service to these customers as well as accommodate any required net metering purchases.

E. NET METERING PURCHASES

54. UGI Electric currently has 30 new applications for net metering systems to be installed in the Company's service territory within the next 3 years. Related to GSR-1 versus GSR-2 service criteria, 16 of these installations will have default supply impacts

under 100 kW that will impact GSR-1, and 14 will have default supply impacts greater than 100kW that impact GSR-2. The facilities impacting GSR-1 will provide up to 186kW of generation, whereas the 14 facilities classified as GSR-2 will provide up to 22 MW of generation. It is possible during the DSP V Term – June 2025 through May 2029 – that additional requests may be filed, or some of these proposed installations will not be completed. While the final total impact of these systems is unclear, the Company is positioning its default supply portfolio to accommodate what may be a significant increase in net metering in a way that is seamless and will appropriately address impacts and costs for default service customers.

55. As part of its review of its portfolio and default service rate structure, UGI Electric is proposing to recognize the impact that customers have on the Company's default supply activities. Specifically, where a customer's (including a net metering customer's) supply peak load impact is less than 100 kW, that customer will be included in GSR-1. Where a customer's (including a net metering customer's) supply peak load impact is greater than or equal to 100 kW, that customer will be included in GSR-2.

56. The Company's GSR-1 procurement portfolio will accommodate and address the potential fluctuation in participating GSR-1 net metering through adjustments in the total load covered by the FPFR contracts, and those net metering customers will be paid for excess generation at the price to compare applicable to GSR-1 customers.

57. GSR-2 net metering will reduce the total PJM spot market purchases made on behalf of the Company's other GSR-2 customers. Where the total net metering generation exceeds GSR-2 demand at any point in time, excess generation will be sold back to PJM. GSR-2 net metering customers will be paid for excess generation at the price-to-

compare applicable to GSR-2 customers. The tariff modifications to effectuate this change are explained in Ms. Hazenstab's testimony, UGI Electric Statement No. 3.

F. AEPS CREDITS FOR GSR-1 AND GSR-2

58. Consistent with DSP III and DSP IV, the Company will procure AEPS credits (in accordance with Section 75.61(b)(15)) for each plan year as specified below:

59. For the June 1, 2020, through May 31, 2021 reporting period (and each successive 12 months thereafter), the Tier I requirement is 8% of all retail sales, of which at least 0.5% of all retail sales are to come from solar generation and the remainder from non-solar Tier I resources. The Tier II requirement is 10% of all retail sales. For GSR-1 load-following supplies, the load-following suppliers will be responsible for obtaining AEPS credits in an amount that corresponds to the amount of retail sales for the relevant load-following delivery period.

60. UGI Electric will procure AEPS credits for its remaining GSR-1 default service procurements and all of its GSR-2 default service procurements through an RFP process similar to DSP IV.[11]

61. The Company proposes using the same AEPS agreement that was approved by the Commission's January 22, 2009 Order (approving the *Joint Petition for Settlement of UGI Electric's AEPS Plan* at Docket Nos. P-2008-2063006 and G-2008-2063688). This AEPS agreement form was used in the Company's DSP III and DSP IV Plans.

62. Under the AEPS Act, the Company's compliance obligations are measured on a Reporting Period basis as defined in 52 Pa. Code § 75.1. This consists of the 12-

[11] The Company will issue an RFP to procure these AEPS credits based on sales estimates, which will be reconciled to actual sales by September 1 of each Plan year.

month period from June 1 through May 31 (i.e., the PJM year). The Company has until September 1 to true-up its AEPS compliance obligations (based on actual retail sales during each Plan year). According to the definition in Section 75.1, the *true-up period* is the period each year from the end of the reporting year until September 1.

63. Currently, UGI Electric conducts its AEPS RFP in May, just before the annual AEPS compliance window ends, with the contract running June through May. In an effort to improve supplier participation, and, by extension, competition and pricing, UGI Electric is proposing to move the AEPS RFP from May to coincide with the first auction of each year, occurring in January through March. By conducting the auction earlier and in alignment with the energy auction, UGI Electric will move to a period where less competition for AECs is occurring; therefore, greater AEC supplies may be available and in turn, potentially cheaper. Further, this will improve the overall auction process efficiency, holding two auctions at the same time. Doing so will help to reduce auction costs and may result in a greater number of wholesale suppliers participating in the AEC auctions. This proposal is discussed in greater detail in Mr. Rouland's testimony, UGI Electric Statement No. 2.

64. UGI Electric is also proposing to adjust its calculations for determining the number of AECs it must procure by increasing the forecasted number of AECs required to cover the block purchases, the FPFR scheduled versus settlement obligation, NYPA supply, Tier I Adjustment, and GSR-2. The adjusted process will first forecast the anticipated usage for these four areas (kWh), and the resulting AEC obligations will increase the result by 15%.

65. Because UGI Electric is forced to forecast its AEC needs for these areas, there is a risk of under-forecasting and, therefore, under-procurement of the AECs needed for state compliance. By calculating the forecast, and then increasing the resulting need by 15%, the Company is expecting to slightly over-procure the AECs needed in any individual auction. These excess AECs can then be rolled into the next year, reducing the AECs needed in that year. To make this possible, UGI Electric is also proposing to include vintage requirements in its procurement plan for AECs.

66. After the true-up period expires, in the unlikely scenario that the Company is still unable to meet its AEPS credit targets in Section 52 Pa. Code § 75.61, the Company would pay the applicable alternative compliance payment(s) specified in 52 Pa. Code § 75.65(b). In such an instance, the Company requests approval to recover these costs through its default service rates. This is the same methodology that the Company utilized in DSP IV.

67. In accordance with 52 Pa. Code § 75.67, UGI Electric will recover the costs associated with the procurement of AEPS credits (during DSP V) from its default service customers through a Section 1307 automatic adjustment clause rate design as was done in DSP IV.

G. TECHNICAL BID REQUIREMENTS

68. In accordance with 52 Pa. Code § 54.185(e)(2), UGI Electric's DSP V includes technical requirements associated with competitive bid solicitations (consistent with 52 Pa. Code § 54.186).

69. The RFPs noted above will be issued to wholesale suppliers that either have Edison Electric Institute ("EEI") agreements in place with UGI Electric or express interest in participating in the bid rounds (as was done in DSP III and DSP IV).

70. In DSP IV, the Company used an independent market monitor that managed the Company's default service bidding process. In DSP V, UGI Electric plans to issue an RFP seeking an auction manager to provide greater service and support to the Company. The auction manager role is described in the testimony of UGI Electric witness Jesse R. Tyahla, UGI Electric Statement No. 1. UGI Electric requests that the Commission approve the Company's use of an auction manager to be secured through an RFP process occurring prior to the commencement of DSP V.

71. For DSP V, the auction manager will conduct the RFPs in the same manner as was done in DSP IV. The auction manager and UGI Electric will advertise notice of the RFPs in industry publications, and post the RFPs on the Company's Energy Management website, as well as questions (with answers) raised by potential suppliers. The website will include the hourly loads of GSR-1 Group customers from October 1, 2010 through the last full month prior to the issuance of the RFP, as well as hourly temperatures for the same period so that potential bidders can calculate anticipated weather normalized hourly loads. The Company also will conduct a conference call open to all potential suppliers where questions about the RFPs can be addressed. The auction manager will be an active participant throughout this process. Potential suppliers are required to submit bids within three to four weeks of the RFP issuance date. The results of the RFP selection process are subject to final Commission approval.

72. In addition, UGI Electric's affiliate, UGI Energy Services, LLC ("UGI Energy Services") should be permitted to participate in the RFPs for DSP V. Neither UGI Electric nor UGI Energy Services has withheld from the market any generation supply in a manner that violates federal law. As such, UGI Electric's affiliate may participate in the

bids and will not be granted any preference or gain preferential access to any non-public information. Accordingly, UGI Electric requests that the Commission approve potential affiliated interest transactions associated with DSP V pursuant to Section 2102 of the Public Utility Code. The RFP process will also be overseen by the auction manager, and the results will be subject to final Commission approval.

73. As was done in DSP III and DSP IV, the load-following RFPs for DSP V will seek a fixed bid price for each tranche. In a departure from the process used in DSP III and DSP IV, the block RFPs will seek a single price for all 24-months of each of the two blocks that will be offered. The blocks will also have a fixed quantity of supply for all 24-months within the block. The RFPs will include a cover letter, a summary with bid instructions, and a bid form to be completed by interested wholesale suppliers. The instructions will refer interested suppliers to the Company's Energy Management website where they can find relevant documents, including, but not limited to, a copy of the EEI form agreement, historical hourly loads and temperatures, number of customers, a sample confirmation agreement and other relevant information. The RFP instructions in DSP V will continue to explain that bidders must provide documentation demonstrating their good standing and compliance with PJM's tariff, operating agreement, reliability agreement, and business practices. These documents are included as exhibits to Mr. Rouland's testimony.

74. The Company is also proposing to include both Bid Assurance and Performance Assurance Collateral as part of DSP V. Both forms of collateral will provide risk protections to UGI Electric and in turn customers, limiting the exposure and additional costs to procure energy supply in the event a supplier fails to execute an agreement or defaults on a contract after execution. In DSP V, UGI Electric proposes to implement a

fixed fee Bid Assurance Collateral amount of $75,000 per tranche for both FPFR and ATC block products. This amount would aid in covering the costs for an additional auction to reacquire supply following a bidder's failure to execute a contract and could also provide some protection should prices have increased. Further, the Company proposes to implement a fixed fee Performance Assurance Collateral amount of $175,000 for FPFR contracts and $100,000 for ATC block contracts. Similar to Bid Assurance Collateral, Performance Assurance Collateral will aid in covering the cost to hold an auction to reacquire supply after a supplier default and provide a buffer should energy prices increase.

75. The Company will provide the load-following and block bid results to the Commission within one business day after the bid responses become due. Thereafter, the Commission will have one business day to review the bid responses and approve or disapprove the Company accepting the winning responses. If the Commission approves of the winning bid responses, the Company will execute transaction confirmations with the winning suppliers. During the course of DSP V, the Company may work to further improve, or shorten, the time between when bid responses are due and when bid awards are approved and confirmed.

H. CONTINGENCY PLAN

76. In accordance with 52 Pa. Code § 54.185(e)(5), the Company's DSP IV incorporates contingency plans in the event that the Company cannot secure wholesale generation supplies required to meet the default service obligation. The contingency plan for DSP V is a pre-described approach on how the Company will proceed based upon the time-gap between product failure and tariff issuance. In most instances, UGI Electric will first re-auction the failed product unmodified. The re-auction will occur approximately one month after the original auction date (i.e., February or August), including renewed outreach

to suppliers to solicit interest, bidder qualification (for any new bidders) and a rebid of the product. Should the re-auction fail, the Company will modify the product(s) before rebid. In the second layer of the contingency plan, depending upon which product failed, the Company will reduce the 12-month FPFR product to a 6-month FPFR and/or reduce the 24-month ATC block to a 6-month ATC block, and then re-auction the modified product(s). The re-auction of the modified product will occur approximately one month later (e.g., March or September) and again include supplier outreach and qualification. Should this modified product auction fail, the final solution for the FPFR and block products is for the Company to fill the supply using the spot market.

77. In addition, the Company is adding a contingency plan applicable to its AEPs auctions. During DSP V, if UGI Electric experiences a failed auction for any of the three tiers of AECs being solicited, the Company will contact AEC Brokers and Aggregators (Brokers), as identified on the Commission's AEPS website, to determine if any Brokers have the necessary AECs, including the vintages required. If the AECs are potentially available in the market, UGI Electric will solicit bids from at least three different Brokers. Brokers will provide a fixed price for all AECs of the specified vintages. The lowest price offering will be selected.

78. These changes will significantly improve the Company's contingency plan process by establishing a clear plan of action and leveraging AEC suppliers already in the market and recognized by the PUC on their website. By soliciting bids from at least three different Brokers, UGI Electric is conducting a competitive process, continuing to solicit for the AECs needed and acquiring them at the least cost. The contingency plan also provides valuable market feedback. If Brokers also explain that a certain type of AECs are

unavailable in the market, UGI Electric can communicate this to the PUC and better inform next steps that will be taken in compliance with AEPS obligations.

I. COMPLIANCE WITH RTO LEGAL AND TECHNICAL REQUIREMENTS

79. In accordance with 52 Pa. Code § 54.185(e)(4), DSPs must include documentation that the plan is consistent with the requirements pertaining to the generation, sale and transmission of electricity of the RTO in the default service provider's territory (i.e., PJM). For DSP V, the Company is continuing its EEI Master Service Agreement and RFP instructions to require that bidders provide documentation demonstrating their good standing and compliance with PJM's tariff, operating agreement, reliability agreement, and business practices.

80. The Company's RFP instructions also require specific bidder certifications demonstrating they are: 1) qualified market buyers and sellers of electricity in good standing with PJM; 2) positioned to obtain and deliver electric generation supplies in PJM; 3) compliant with all applicable PJM requirements; and 4) authorized by the Federal Energy Regulatory Commission ("FERC") to sell and procure energy, capacity and ancillary services at market-based rates.

J. RATE DESIGN PLAN

81. In accordance with 52 Pa. Code § 54.185(e)(3), UGI Electric's DSP V utilizes a default service rate design plan that recovers all reasonable costs for providing default service. DSP V's rate design plan is similar to the one used in DSP IV. The rate design for DSP V appears in Appendix A to this Petition, which is an updated copy of *Rider B - Generation Supply Service Surcharge* ("Rider B") to the Company's Electric

Service Tariff. Rider B sets forth the schedule of default service rates, rules and conditions for recovering default service costs. [12]

82. The default service rate design plan for DSP V is similar to the rate design plan adopted in DSP IV in that it recovers default service costs on a full and current basis through a Section 1307 reconcilable adjustment clause (including costs for complying with the AEPS Act). Currently, the Company calculates rate changes on a quarterly basis. UGI Electric is proposing to change to semi-annual rate changes. During DSP V, the rates will become effective June 1 and December 1 to align with the June 1 start of the DSP V Plan.

83. The Company's DSP V will include a default service rate design that recovers costs associated with the preparation and provision of DSP V, as well as the default supply costs purchased pursuant to it for the GSR-1 and GSR-2 groupings, including AEPS credits and any required power purchases pursuant to net metering requirements. The reflection of these costs in rates is fully described in the testimony of UGI Electric witness Tracy A. Hazenstab, UGI Electric Statement No. 3.

K. AGREEMENTS AND FORMS USED TO PROCURE ELECTRIC SUPPLY FOR DSP V

84. In accordance with 52 Pa. Code § 54.185(e)(6), the Company is providing copies of its agreements and forms used in the procurement of electric supply for default service customers. These documents include the Company's master supply agreement (i.e., EEI Agreement), RFP documents, and credit and confidentiality agreements. These documents are included as exhibits to Mr. Rouland's testimony.

[12] Appendix A also contains a copy of Rule 5.6(b) of the Company's Electric Generation Supplier Coordination Tariff (regarding monthly charges for the Standard Offer program and how they are to be allocated to suppliers on a per capita basis).

85. UGI Electric plans to acquire default service supplies for DSP V through an EEI Agreement that is similar to the form used in DSP IV. UGI Electric will use the revised EEI agreement and RFP instructions for its load-following and block purchases in DSP V.

L. GENERATION CONTRACTS GREATER THAN 2 YEARS

86. In accordance with 52 Pa. Code § 54.185(e)(7), the Company is identifying generation contracts of greater than 2 years in effect that will be used to provide default service. The only contract that UGI Electric plans to use during the term of DSP V with a term that is greater than 2 years is the Allegheny Agreement. A copy of the agreement is included as an exhibit to Mr. Rouland's testimony. The Company made procurements under this long-term agreement in DSP III and DSP IV and plans to continue these purchases in DSP V. This contract is fully described above in Section III.C.3, *supra*, and in the testimony of UGI Electric witness James M. Rouland, UGI Electric Statement No. 2.

M. RETAIL ENHANCEMENT PROGRAMS FOR DSP V

87. Consistent with DSP IV, DSP V will include two retail enhancement programs: 1) the New/Moving Customer Referral Program; and 2) the Standard Offer Customer Referral Program. The Company is not proposing any modifications to these programs as part of DSP V.

IV. <u>LEGAL STANDARDS</u>

A. THE COMPANY'S PROCUREMENT PLANS MEET ACT 129'S LEGAL STANDARDS

88. The procurement methodologies under DSP V meet the requirements of Act 129 that a procurement plan shall be designed to be "the least cost to consumers over time" and shall include a "prudent mix" of contracts. The hourly price service for GSR-2 Group

customers, and the competitive solicitations for block purchases and full requirements contracts serving GSR-1 Group customers, represent a "prudent mix" of procurement contracts for UGI Electric's default service customers and will provide default service customers with access to an adequate and reliable supply of generation at least cost over time. *See* 66 Pa. C.S. § 2807(e).

89. Specifically, Act 129 requires that power "shall be procured through competitive procurement processes" including auctions, requests for proposals and/or competitively procured bilateral agreements procured at no greater than the cost of obtaining generation under comparable terms in the wholesale market, and such procurement must be a "prudent mix" of spot market purchases, short-term contracts and long-term purchase contracts. *Id*. § 2807(e)(3.1)-(3.2).

90. UGI Electric's DSP V procurement plan is similar to the procurement plans of other EDCs in Pennsylvania and complies with the legal requirements of a "prudent mix" of contracts "designed to ensure adequate and reliable service at the least cost to customers over time. DSP V also meets the procurement requirements of Act 129 by utilizing competitive procurement processes. Further, the Company's DSP V is consistent with the Commission's RMI Orders at Docket No. I-2011-2237952 and, as required by 66 Pa. C.S. § 2807(e)(7), ensures that "the costs of providing service to each customer class are not subsidized by any other class."

91. The procurement process is explained in detail in the direct testimony of UGI Electric witness Mr. Rouland, UGI Electric Statement. No. 2 (Appendix C).

92. For all of the reasons set forth above, this default service plan meets the standards set forth in Act 129 and enables the Commission to make the necessary findings per Section 2807(e)(3.7) as follows:

- UGI Electric's Plan includes prudent steps necessary to negotiate favorable generation supply contracts;
- UGI Electric's Plan includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis; and
- Neither UGI Electric nor its affiliated interests have withheld from the market any generation supply in a manner that violates federal law.

B. WAIVERS

93. UGI Electric recognizes the Commission's default service regulations and policy statement intend that DSPs be tailored to acquire default supplies for specific customer groupings with maximum registered peak loads of: 1) less than 25 kW for residential and non-residential customers; 2) between 25 kW and 500 kW for non-residential customers; and 3) greater than 500 kW for certain non-residential customers (i.e., commercial and industrial customers). 52 Pa. Code §§ 54.187(i)-(k) and 69.1805.

94. However, the regulations and policy statement also provide that DSPs may propose alternative divisions of customers.

95. As noted above, UGI Electric proposes in this Petition to continue to acquire default service supplies for two groups – all customers with supply peak load impacts less than 100 kW, and customers with supply peak load impacts of 100 kW or greater, and, to the extent necessary, requests a waiver from the customer groupings recommended in 52 Pa. Code §§ 54.187 and 69.1805 to permit this procurement strategy to continue.

96. As also noted above, UGI Electric is proposing semi-annual rate changes for GSR-1 customers. Section 54.187(i) of the Commission's regulations provides that

default service rates for customers with a maximum registered peak load of 25 kW to 500 kW should be adjusted on a quarterly basis or more frequently. 52 Pa. Code § 54.187(i). UGI Electric requests a waiver of this regulation to allow semi-annual rate changes for customers from 25kW to 100 kW.

97. These waivers are appropriate given the small size of default service loads on UGI Electric's system.

98. The Commission's default service regulations provide that a DSP shall provide notice of the initial default service rates and terms and conditions of service 60 days before their effective date, or 30 days after bidding has concluded, whichever is sooner, unless another time period has been approved by the Commission. 52 Pa. Code § 54.188(e)(2). The Company's tariff currently provides for a 30-day notice, and the Company requests that it be able to continue to provide 30 days' notice in advance of PTC changes.

99. The Company also requests any additional waivers needed to implement its DSP V Plan as set forth in this filing.

C. THE PROPOSED RETAIL PROGRAMS ARE IN THE PUBLIC INTEREST

100. The Commission has encouraged EDCs to offer retail market programs, including new and moving customer referral programs and Standard Offer programs to residential and small commercial and industrial customers. *See, e.g.* March 2, 2012 RMI Order.

101. UGI Electric proposes to continue to offer the New/Moving Customer Referral program to its customers during the term of DSP V.

102. Likewise, UGI Electric stands ready to offer a Standard Offer program to refer customers to EGSs should an EGS(s) decide to participate in the Company's Standard Offer program during the term of DSP V.

103. These customer referral programs are in the public interest because they support retail choice.

V. CUSTOMER NOTICE

104. UGI Electric will publish notices containing similar information in the major newspapers serving its service territory. Finally, all notices will refer to UGI Electric's website, (http:// www.ugi.com/rate-filing), where a copy of the entire filing will be maintained.

105. UGI Electric is also notifying proposed customer-generators whose facilities would be affected by the GSR-2 classification in this Petition. The Company has no current net metering customers that would be impacted by the proposal.

106. In addition to the above notices, UGI Electric also is serving copies of this filing on the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, the Office of Small Business Advocate, all EGSs registered in UGI Electric's service territory and PJM.

VI. **<u>CONCLUSION</u>**

WHEREFORE, UGI Electric respectfully requests that the Commission, no later than January 2025: (1) approve the default service program set forth in this Petition; (2) grant affiliated interest approval for transactions with a UGI Electric affiliate in the event such an affiliate submits a winning bid under the default service program's proposed RFP processes; (3) grant any waivers required to implement the default service program set forth in this Petition, including a waiver of the Commission's regulation at 52 Pa. Code § 54.187 to allow UGI Electric to acquire and manage default supplies for the GSR-1 and GSR-2 customer groups as defined herein; (4) authorize UGI Electric to file tariff sheets substantially in the form of the *pro forma* tariff sheets set forth in Appendix A to this Petition on or before May 2, 2025 to be effective June 1, 2025; (5) authorize UGI Electric to file tariff sheets no later than thirty (30) days in advance of June 1 and December 1, beginning June 1, 2025 specifying the applicable GSR-1 Group default service rates; (6) re-approve UGI Electric's retail choice market enhancement programs and grant, to the extent required, any affiliated interest approvals necessary for UGI Electric affiliates to participate in such programs; (7) approve UGI Electric's use of an auction manager that will be secured through an RFP process as its independent third party evaluator; and (8) grant such other relief as the Commission deems appropriate.

Respectfully submitted,

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Date: May 31, 2024

Attorneys for 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 (DSP V) for the Period of June 1, 2025 through May 31, 2029	: : : : :	Docket Nos. P-2024- G-2024-

VERIFICATION

I, Paul J. Szykman, being the Chief Regulatory Officer for UGI Utilities, Inc. – Electric Division, hereby state the facts set forth in the foregoing petition are true and correct to the best of my knowledge information and belief, and that if asked orally at a hearing in this matter, my answers would be the same as set forth herein. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: 5/30/2024

DocuSigned by:
0D42C0CB3822401...
Paul J. Szykman

APPENDIX A

UGI UTILITIES, INC. – ELECTRIC DIVISION

ELECTRIC SERVICE TARIFF

RULES AND RATES
FOR ELECTRIC DISTRIBUTION SERVICE AND
CHOICE AGGREGATION SERVICE

in the following service territory:

LUZERNE COUNTY

City of Nanticoke, and Boroughs of Courtdale, Dallas, Edwardsville, Forty-Fort, Harvey's Lake, Kingston, Larksville, Luzerne, New Columbus, Plymouth, Pringle, Shickshinny, Sugar Notch, Swoyersville, Warrior Run, West Wyoming and Wyoming.

First Class Townships of Hanover and Newport, and Second Class Townships, of Conyngham, Dallas, Fairmount, Franklin, Hunlock, Huntington, Jackson, Kingston, Lake, Lehman, Plymouth, Ross and Union.

WYOMING COUNTY

Townships of Monroe and Noxen

Issued: Effective for Service Rendered on and after:

Issued by:
Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

THIS TARIFF MAKES CHANGES TO THE EXISTING RATES (PAGE 2).

LIST OF CHANGES MADE BY THIS SUPPLEMENT

(Page Numbers Refer to Official Tariff)

Pursuant to the Final Order entered ____________________ approving the Default Service Program at Docket No. __________________, the following changes have been made to incorporate default service rules beginning June 1, 2025 along with calculated default generation supply service rates effective June 1, 2025:

Rules and Regulations – 17. Net Metering, Pages 30 – 32

- 17-a(3) – Removed rate schedule names for customer types.
- 17-a(4) – Removed outdated language requiring that customer-generators have independent load.
- 17-c(1) – Added language to clarify the Price to Compare that will be used to calculate compensation owed to customer-generators and the timeframe used to define the calculation cycle. Also, added language to define the calculation for compensation to customer-generators served under GSR-2.
- 17-e & 17-f – Removed rate schedule names.
- 17-g – Added language to define the payment distribution timeline.

Rider B – Generation Supply Service Surcharge, Pages 39-41

- Dates have been revised to reflect the Default Service rules beginning June 1, 2025.
- Revised GSR assignment to be based on supply peak load impact and added definition of supply peak load impact.
- Revised timeframe of GSR classification to be determined annually.
- Revised rate calculation frequency from quarterly to semi-annually.
- Added interim filing language for GSR-1.
- Revised GSR-1 formula to include “F” – relative cost factor and added the definition.
- Deleted references to transmission revenue from the EC calculation definition and GSR-2 costs.
- Updated ECA, SEC, Sint language to align with proposed rate updates.
- Added Non-Residential GSR-1 Rate.
- Eliminated migration rider and reverse migration rider from GSR-1 and GSR-2 customers.
- Added formula to show calculation of GSR-2 rate.
- Clarified definition of Price to Compare for GSR-1 customers. Added language to define Price to Compare for GSR-2 customers.
- Clarified information to be provided in annual reconciliation statement.

RULES AND REGULATIONS (continued)

17. NET METERING

17-a Applicability. This rule sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

(1) Customer-generators served under Rate Schedules R, GS-1, GS-4, GS-5, and LP who install a device or devices which are, in the Company's judgment, subject to Commission review a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system are eligible for net metering.

(2) This rule is available to installations where any portion of the electricity generated by the renewable energy generating system offsets part or all of the customer-generator's requirements for electricity.

(3) A renewable customer-generator, under this rule, is a non-utility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service ~~(Rate R)~~ or not larger than 3,000 kilowatts at other customer service locations ~~(Rate GS-1, GS-4, GS-5, and LP)~~, except for a Customer whose system is above 3 megawatts and up to 5 megawatts who may qualify its alternative energy system for customer-generator status if, as set forth in the Commission's regulations: (a) the Customer makes its system available to operate in parallel with the grid during grid emergencies; or (b) the Customer's system is located within a microgrid. **(C)** **(C)**

(4) ~~To qualify for net metering, the customer-generator must, among other things, have electric load, independent of the alternative energy system, behind the meter and point of interconnection of the alternative energy system. To be independent of the alternative energy system, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system.~~ **(C)**

(5) Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. The net metering rules are not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

(6) Service is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

(7) Review and approval of all customer-generator applications and interconnections shall be in accordance with the Commission's regulations.

17-b Metering Provisions. A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. If the Customer agrees, a dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

(C) Indicates Change

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator’s expense.

(3) Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternate energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for the disposition of those credits.

(4) Virtual meter aggregation on properties owned or leased and operated by the same customer-generator shall be allowed for purposes of net metering. Virtual meter aggregation shall be limited to meters located on properties owned or leased and operated by the same customer-generator within two (2) miles of the boundaries of the customer-generator’s property and within the Company’s service territory. All service locations to be aggregated must be Company service location accounts held by the same individual or legal entity receiving retail electric service from the Company and have measurable load independent of any alternative energy system. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing their account on a virtual meter aggregation basis.

17-c Billing Provisions. The following billing provisions apply to customer-generators in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at full retail rate, consistent with Commission regulations. If a customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator’s kilowatt-hour usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours that are not offset by electricity used by the customer-generator in subsequent billing periods shall continue to accumulate until the ~~end of the year.~~final billing period on or before the end of the PJM year (May of each year). At the end of each PJM year, the Company will compensate the customer-generator for any remaining excess kilowatt-hours generated by the customer-generator that were not previously credited against the customer-generator’s usage in prior billing periods at the ~~Company’s~~ Customer’s applicable Price to Compare (PTC-1 or PTC-2). Applicable PTC-2 rates shall be applied to the respective hours of excess generation. ~~(PTC-1) rate for customers receiving default service on GSR-1.~~ The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule. **(C)** **(C)** **(C)** **(C)**

(C) Indicates Change

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

(3) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs must be stated in the service agreement between the customer-generator and the EGS. The Company shall credit customer-generators who are EGS customers for each kilowatt-hour of electricity produced at the Company's unbundled distribution kilowatt-hour rate. The distribution kilowatt-hour rate credit shall be applied monthly against kilowatt-hour distribution usage. If the customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in any billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's unbundled kilowatt-hour distribution usage in subsequent billing periods until the end of the year when all remaining unused kilowatt-hour distribution credits shall be zeroed-out. Distribution credits are not carried forward into the next year.

(4) For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by the same customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

17-d Application. Customer-generators seeking to receive service under the provisions of this rule must submit a written application to the Company demonstrating compliance with the net metering provisions and quantifying the total rated generating capacity of the customer-generator facility.

17-e Minimum Charge. The Minimum Charges under ~~Rate Schedule R, GS-1, GS-4, GS-5, and LP~~the applicable rate schedule apply for installations under the net metering rules. **(C)**

17-f Applicable Charges and Fees. Bills rendered by the Company under this rule shall be subject to charges and fees applicable to ~~Rate Schedules R, GS-1, GS-4, GS-5, and LP.~~the assigned rate schedule. **(C)**

17-g Payment distribution. Any remaining credit balance as of the end of the May billing period will be paid to the customer via check within 90 days of May 31. **(C)**

(C) Indicates Change

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE

Company will supply Default Generation Supply Service (GSS) to Customers in the Company's service territory not receiving service from an EGS. The rules and rates contained herein apply to service provided on and after June 1, ~~2021~~2025. **(C)**

For Customers served through the Company's GSS, a Generation Supply Rate (GSR) shall be applied to each kilowatt hour of energy used by the Customer. Separate GSRs shall be calculated ~~and apply to the rate schedules listed below~~and apply in accordance with the following:~~.~~ **(C)** **(C)**

GSR-1 shall apply to all residential customers as well as non-residential customers with a supply peak load impact less than 100 kW. **(C)**

GSR-2 shall apply to all non-residential customers with a supply peak load impact greater than or equal to 100 kW. **(C)**
~~GSR-1 shall apply to Rate Schedules R, GS-1, GS-5, FCP, BLR, OL, SOL, MHOL, LED-OL, SL, SSL, MHSL, LED-SL and LED-CO.~~
~~GSR-1 shall also apply to Rate Schedules GS-4 and LP where the Customer's annual peak load is less than 100 kW.~~
~~GSR-2 shall apply to Rate Schedules GS-4, LP, and HTP where the Customer's annual peak load is greater than or equal to 100 kW.~~

Supply peak load impact will be determined on a Customer's net demand contribution impact to the Company's default service procurement activity, as determined upon the net power flow from or into the Company's distribution system. **(C)**

The supply peak load impact used to assign customers to the applicable GSR rate shall be the Customer's highest supply peak load impact (kW) in the most recent 12-month period ending September 30. ~~Customer's highest billing demand in the twelve-month period ending September 30, 2020 shall be the annual peak load determinant for purposes of applying the GSR.~~ For new Customers without a twelve-month billing history, the ~~billing demand~~ supply peak load impact shall be based on the Company's estimate using factors such as, but not limited to, similarly equipped buildings, similarly utilized buildings and square footage. As related to customer-generators, ~~.~~this estimate shall also be inclusive of the nameplate capacity of the generation system. **(C)** **(C)**

The GSR-1 rate shall be calculated every ~~three~~ six months beginning June 1, ~~2021~~2025. The GSR-1 rate shall be filed with the Commission with at least thirty days' notice prior to each ~~three~~six-month period and shall be posted on the Company's website. If the GSR-1 calculation results in a change in rate that is less than 2%, the Company, in its sole discretion, may file with the Commission a GSR-1 rate that is unchanged from the prior period. Pursuant to 52 Pa. Code § 69.1809(c), the Company may propose an interim reconciliation prior to the next adjustment interval. The rate will be calculated as follows: **(C)** **(C)**

$$GSR\text{-}1 = (((EC*F)/SEC) + (ECA/SECA) + (Int/Sint)) * (1/(1\text{-}T))$$ **(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	1.02	0.93

ECA = Net over or under collection of the EC defined above to be refunded/recovered and calculated across relative cost factors. The ECA will be reconciled ~~quarterly~~ based on actual EC revenues received and actual EC costs incurred for the ~~three~~six-month period ending two months prior to the filed GSR effective date. ~~Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-1 Customers shall be included in the ECA component of the GSR-1 beginning June 1, 2021. The over/under collection existing as of May 31, 2021 shall be allocated to GSR-1 and GSR-2 Customers based on the percentage of the actual sales during the period of the over/under collection attributed to those Customers classified as GSR-1 and GSR-2 as of June 1, 2021.~~ In the event the ECA would result in less than (or equal to) a five percent (5%) change in the average total Residential bill, the Company will refund/recover the balance over a ~~three~~six-month period. In the event the ECA would result in more than a five percent (5%) change in the average total Residential bill for default service, the Company will refund/recover the balance over a ~~six, nine, or~~ twelve-month period ~~(as determined by the Company)~~. **(C)** **(C)** **(C)** **(C)**

Int = When revenues exceed costs, the over collections shall be refunded to Customers with interest. When costs exceed revenues, the under collections shall be collected from Customers with interest. Interest on over collections and under collections shall be computed at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal. Interest shall be computed monthly from the month the over collection or under collection occurs to the effective month that the over collection is refunded or the under collection is collected.

T = The Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates, expressed in decimal form.

SEC = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the next ~~three-month~~computation period, in kilowatt hours. **(C)**

SECA = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the refund/recover period, in kilowatt hours.

Sint = The Company's projected sales for all default service Customers on rate schedules included in the GSR-1 group for the ~~twelve-month period beginning December 1~~next computation period, in kilowatt hours. **(C)**

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

Residential	Non-Residential
x.xx	x.xx

(C)

~~10.525 ¢/kWh~~

~~GSR-2 shall be calculated for each default service Customer in this group. Company shall bill each Customer on a calendar month based upon actual costs incurred to serve the Customer. The costs will be allocated as follows:~~ **(C)**

~~Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 Customer by multiplying the Customer's actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.~~

(C) Indicates Change

RIDER B
GENERATION SUPPLY SERVICE SURCHARGE (continued)

GSR-2 shall be calculated for each default service Customer in this group. Company shall bill each Customer on a calendar month based upon actual costs incurred to serve the Customer. The costs will be allocated as follows: **(C)**

GSR-2 = (HEC + HPC + HTC) * (1/(1-T)) **(C)**

HEC = Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 Customer by multiplying the Customer's actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.

HPC = Other power costs incurred by the Company to acquire electric supply for the GSR-2 group for the month shall be allocated to each GSR-2 Customer based on metered sales. Other power costs include alternative energy credits and all PJM bill ~~line item~~line-item expenses/credits excluding the following: costs for capacity services, transmission services, network transmission service credits and firm point-to-point transmission service credits/expenses. Other costs included are administrative costs, net metering costs related to required excess power purchases pursuant to PTC-2, legal costs, taxes, and any other applicable costs of providing default service for the GSR-2 group. ~~The actual costs shall be reduced by the actual transmission revenues to be collected in accordance with the applicable rate schedules included in the GSR-2 group.~~ **(C)** **(C)**

HTC = Cost for capacity and transmission services based on the PJM bill ~~line item~~line-item expenses/credits applicable to these services shall be allocated to each Customer in the GSR-2 group. The capacity costs shall include the PJM bill line items for locational reliability, capacity transfer rights, RPM auction, and capacity resource deficiency. The capacity costs shall be allocated to each Customer based on each Customer's peak load contribution (PLC). The transmission costs shall include the PJM bill line items for network integration transmission service charges, transmission enhancement service charges/credits, and non-firm point-to-point transmission service charges/credits. The transmission costs shall be allocated to each Customer based on each Customer's network service peak load value (NSPL). Any expense/credit line items added by PJM related to these services shall be allocated based on the Customer's applicable PLC and NSPL. **(C)**

~~Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-2 Customers that migrate from rate GSR-1 shall be refunded/recovered from those Customers directly over 12 billing periods beginning September 1, 2021. The over/under collection existing as of May 31, 2021 shall be allocated to GSR-1 and GSR-2 Customers based on the percentage of the actual sales during the period of the over/under collection attributed to those Customers classified as GSR-1 and GSR-2 as of June 1, 2021. Customers who undergo reverse migration, switching from GSR-2 to GSR-1 during the DSP IV term, will be exempted from any over/under collections as reflected in the Company's E-factor (existing as of May 31, 2021) for a period of 12 months after returning to GSR-1.~~ **(C)**

T = All costs for GSR-2 Customers shall include the Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates. **(C)**

Price to Compare: The Price~~-To-~~ to Compare ("PTC") for GSR-1 (PTC-1) shall include the ~~Energy Charge ("EC"), and the Energy Cost Adjustment ("ECA"), contained in this Tariff. The Price-To-Compare shall also include the~~GSR-1 rate and the State Tax Surcharge in Rider A. Separate PTC-1 rates will apply to residential and non-residential customers. ~~PTC is not applicable to GSR-2.~~The Price to Compare for GSR-2 (PTC-2) shall include the GSR-2 rate and the State Tax Surcharge in Rider A. **(C)**

Annual Reconciliation Statement: On June 30 of each year, the Company will file with the Commission, its Annual Reconciliation Statement for the GSR-1 rate, with the actual costs and revenue for both residential and non-residential customers ~~for~~aggregated, for the preceding 12 months ending May 31. **(C)**

(C) Indicates Change

APPENDIX B

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY
OF
JESSE R. TYAHLA

UGI ELECTRIC STATEMENT NO. 1

Dated: May 31, 2024

I. Introduction

Q. Please state your name and address.

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

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

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

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

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

Q. What is your educational background?

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

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

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

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

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

Q. Are you sponsoring any exhibits?

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

II. CURRENT PLAN – DSP IV

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

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

III. SETTLEMENT COMMITMENTS FROM THE DSP IV PROCEEDING

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

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

Q. Did the Company undertake the required study?

A. Yes. The Company hired NorthBridge Group to perform the procurement study. In undertaking its evaluation, NorthBridge Group reviewed data from DSP III and DSP IV through the Fall of 2021. The study identified the individual cost components associated with default service supply for UGI Electric's residential and non-residential GSR-1 customers under both block-and-spot and fixed-price, full requirements ("FPFR") product procurement methods. The cost components reviewed included Energy, Capacity, Network Integration Transmission Service, and Other Costs. The Company filed the study on June 29, 2022, consistent with its commitment in the settlement of DSP IV. A copy of that filing is attached to my testimony as JRT-2. As described in the filing, the Company proposed that it would not implement the conclusions of the study until DSP V.

Q. What did the study conclude?

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

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

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

IV. <u>PROPOSED PLAN – DSP V</u>

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

A. In this proceeding, the Company seeks to implement its DSP V plan during the four-year period from June 1, 2025 through May 31, 2029. The Commission's Default Electric Service ("DES") Policy Statement, at 52 Pa. Code § 69.1804, encourages the use of a DSP term of two to three years, unless otherwise approved by the Commission. The Commission approved a four-year term for the Company's DSP III and DSP IV plans, the latter of which is scheduled to end on May 31, 2025. This extended term, as compared to earlier Default Service Plans, has improved the efficiency of the plan by decreasing the time and expense associated with regulatory proceedings. In addition, the Commission has approved four-year default service plans for other default service suppliers, including PPL Electric Utilities Corporation, Duquesne Light Company, the First Energy Companies, and PECO Energy Company. UGI Electric seeks the same allowance to implement its DSP V over a four-year term.

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

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

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

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

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

A. Yes. In advance of its filing and in support of its procurement process, UGI Electric obtained a consultant, Daymark Energy Advisors, Inc., to conduct a thorough evaluation of its DSP performance to date and to make recommendations for procurement practices that are appropriate for UGI Electric's size and load profile. UGI Electric has not had a comprehensive evaluation of its portfolio and performance conducted by an independent third party since the implementation of its DSP in 2008, and the market has evolved significantly since that time. The evaluation included, among other factors, a review of the Company's auction results and ensuing costs to date, customer rate group usage patterns, options for risk management, portfolio structures of other Pennsylvania EDCs, portfolio composition of similarly situated entities, etc. Mr. Rouland's testimony provides a discussion of the review process and makes recommendations based on that evaluation. The costs associated with Daymark's review and evaluation are included in the administrative costs reflected in DSP V and amortized over the four-year life of the plan, as described by UGI Electric witness Ms. Hazenstab, UGI Electric Statement No. 3.

V. AUCTION MANAGER REQUEST FOR PROPOSAL

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

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

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

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

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

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

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

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

Finally, UGI Electric is seeking comprehensive post-auction support. This includes facilitating communication between UGI Electric and suppliers – execution of transaction confirmations, return of bid collateral, transfer of performance assurance, and answering of final auction-related questions. The auction manager will be responsible for ensuring that all necessary documentation is complete and will transfer data and documents associated with the entire auction process to UGI Electric for its records. Once all post-bid day contract management activities are complete, the auction manager will be expected to conduct supplier outreach to solicit feedback on the entire auction process – successes, concerns, and other related opportunities for improvement (or maintenance), and provide UGI Electric with post-auction analysis that includes any recommended updates or alterations to improve the quality of future auctions.

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

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

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

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

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

Q. Does this conclude your testimony?

A. Yes.

UGI Electric

Exhibit JRT-1

Jesse R. Tyahla

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

Experience

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

Director – Energy Supply & Planning

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

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

Director – Supply Origination & Business Development

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

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

Manager – Gas Supply Trading

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

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

Analyst – Supply and Asset Optimization

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

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

Supply Analyst

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

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

Rates Analyst

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

Education

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

- Concentration: Finance
- Cum. GPA: 3.78

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

- Major: Economics
- Cum. GPA: 3.69

UGI Electric

Exhibit JRT-2

Michael S. Swerling, Esq.

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

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Valley Forge, PA 19482-0858

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

June 29, 2022

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

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

Dear Secretary Chiavetta:

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

I. BACKGROUND

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

The study would review data from DSP III and DSP IV through at least the Fall of 2021. Id. Finally, the study would "evaluate the relative costs to GSR-1 residential and non-residential customers associated with: (1) both block-and-spot and full requirements procurements methods; and (2) both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement." Id. at 7-8. Concurrent with the Procurement Study, the Company would recommend "whether to: (1) continue its existing combined procurement methodology for residential and non-residential customers under the single GSR-1 rate; (2) propose separate procurements for residential and non-residential GSR-1 customers; or (3) maintain combined procurements with differentiated rates for residential and non-residential GSR-1 customers." Id. at 8.

II. GSR-1 PROCUREMENT COSTS BY CUSTOMER GROUP

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

III. RECOMMENDATION

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

Sincerely,

/s/ Michael S. Swerling
Michael S. Swerling

Enclosures: Supporting Information
Certificate of Service

CERTIFICATE OF SERVICE

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

VIA E-FILE & ELECTRONIC MAIL

E-FILE:

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Date: June 29, 2022

/s/ Michael S. Swerling
Michael S. Swerling

Attachment A

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

Prepared for UGI Utilities, Inc.

Scott G. Fisher
David C. Coleman
The NorthBridge Group

June 24, 2022

THE NORTHBRIDGE GROUP
ECONOMIC & STRATEGIC CONSULTING

Table of Contents

I. Executive Summary

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

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

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

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

The main conclusions of our study are as follows:

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

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

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

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

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

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

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

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

II. Default Service Supply Relative Cost Analysis

A. Overview

This section identifies the cost components associated with default service supply for UGI's residential and non-residential GSR-1 customers under both block-and-spot and fixed-price, full requirements ("FPFR") product procurement methods, and it presents an analysis of the relative cost for each of these two customer groups.

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

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

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

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

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

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

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

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

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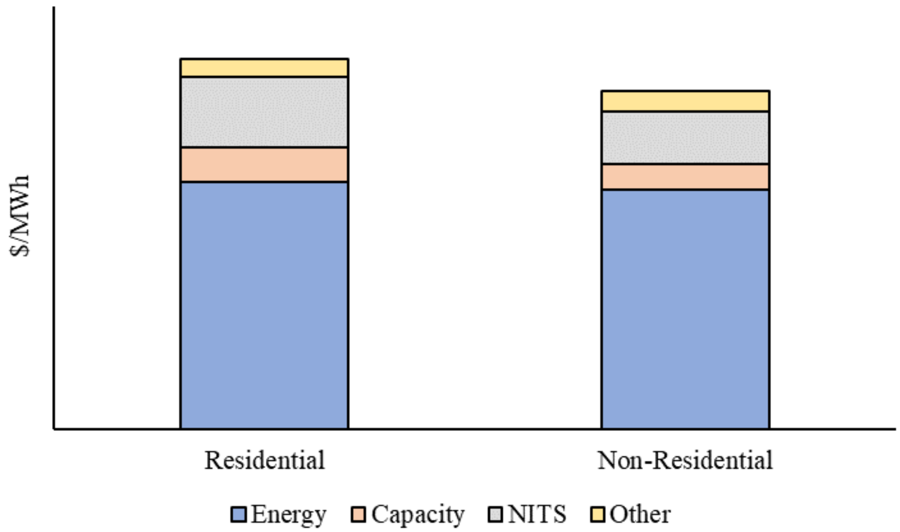
[6] Some of these costs are credits, such as marginal loss credits (monetary amounts that PJM allocates to Load Serving Entities that are reflective of overcollections of line loss costs embedded in wholesale hourly energy prices) and auction revenue rights credits (monetary amounts that PJM allocates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

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

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

Illustrative Default Service Supply Cost Build-Up



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

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

B. Energy Cost Estimation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Capacity Cost Estimation

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

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

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

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

$$\begin{aligned}
&Forecast\ Load_{DefaultServiceGroup} \\
&\qquad = ZonalForecast\ *\ HistoricalClassFraction_{TotalGroup/Zonal} \\
&\qquad *\ Historical\ RetainedFraction_{DefaultServiceGroup/TotalGroup}
\end{aligned}$$

D. Network Integration Transmission Service Cost Estimation

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

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

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

E. "Other Costs" Estimation

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

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

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

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

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

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

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

In sum, the "other costs" estimates for the UGI residential customer group and the UGI non-residential GSR-1 customer group represent the default service supply costs that are not captured in the energy, capacity, and NITS cost estimates, including costs that result from the risks associated with default service supply. Furthermore, these estimates are based on solicitation results for 58 FPFR default service supply products procured in 22 solicitations over approximately the past five years.

UGI GSR-1 Solicitations and Products Analyzed

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

PECO Residential and Small Commercial Solicitations and Products Analyzed

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

F. Development of Relative Costs by Customer Group

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

Relative Cost Analysis: June 2022 – May 2023

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

Relative Cost Analysis: June 2023 – May 2024

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

Relative Cost Analysis: June 2024 – May 2025

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

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

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

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

III. Evaluation of Combined Versus Separate Procurements

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

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

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

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

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

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

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

Indicative Analysis of Pennsylvania Utilities' FPFR Default Service Solicitations

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

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

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

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

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

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

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

and its results were rejected.[18]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

V. Appendix

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

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

APPENDIX C

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY
OF
JAMES M. ROULAND

UGI ELECTRIC STATEMENT NO. 2

Dated: May 31, 2024

I. Introduction

Q. Please state your name and address.

A. My name is James M. Rouland. My business address is 370 Main Street, Suite 325, Worcester, MA 01608.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Are you sponsoring any exhibits?

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

II. OVERVIEW OF HISTORIC DSP STRUCTURE AND PERFORMANCE

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

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

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

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

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

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

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

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

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

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

A. For FPFR contracts, the Company issued RFPs seeking 6-, 12-, and/or 24-month supply terms. Of note, the 6-month contracts were only used at the commencement of the plan and not as part of the rolling 'steady state', which was comprised of the mix of 12- and 24-month contracts layered in throughout the majority of the DSP period. The first procurement by the Company in DSP IV included three load-following tranches for bid: (1) a 6-month FPFR tranche providing supply from June 2021 through November 2021; (2) a 12-month FPFR tranche providing supply from June 2021 through May 2022; and a (3) 24-month FPFR tranche providing supply from June 2021 through May 2023. Each tranche represented approximately 25% of the total estimated default service supply obligation, or 75% in total, after the approximately 25% of the portfolio covered by the block contracts. It is also important to note that the load obligation for the FPFR products was also reduced to account for the approximately 264 kW of long-term Power Authority of the State of New York ("NYPA") power supply, as described later in my testimony.

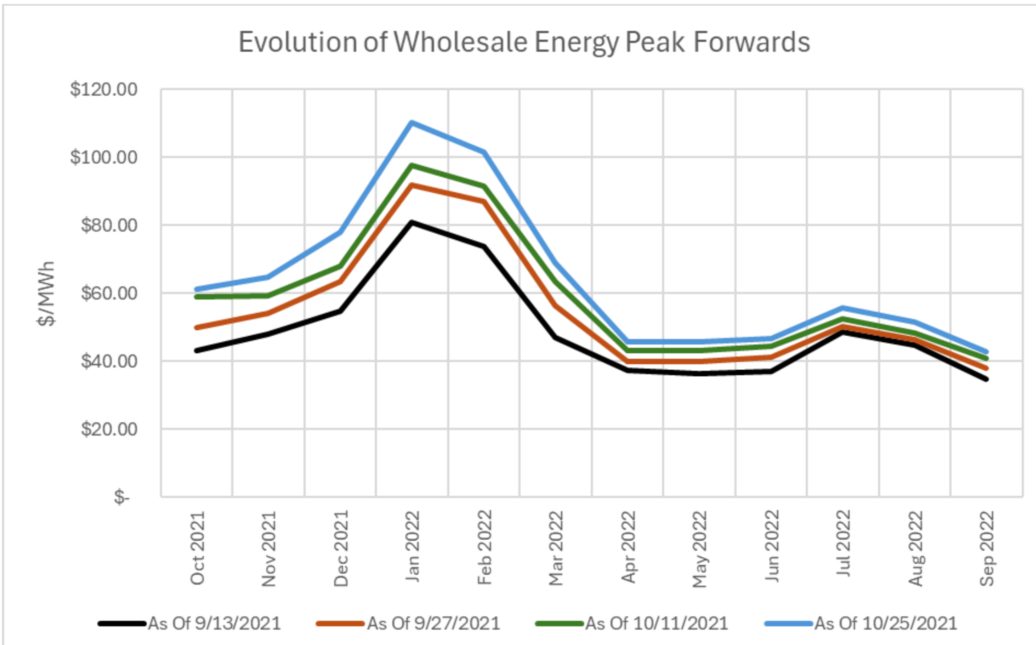
Q. Please summarize the procurement results obtained by UGI Electric in DSP IV.

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

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

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

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



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

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

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

III. <u>DSP V DEVELOPMENT APPROACH</u>

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

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

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

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

A. UGI Electric sought to build a product mix, both as to product type and term of contract, that balances market reflectivity and price stability. Market reflectivity refers to how closely any given product tracks the active energy market at that point in time – typically the spot energy market. Price stability refers to the relative volatility of contract prices and the relative rate change between customer rate changes or from one price-to-compare period to the next. Increasing market reflectivity, under normal market conditions at a point in time, often provides the lowest average price; however, as seen with the spot market, it is the most volatile and can result in extremely high prices during market events. More price stable (i.e. fixed price) products reduce that volatility but may result in a higher relative premium for that stability. In short, the greater the market reflectivity, the greater the risk of price volatility that is transferred to the customer; the greater the price stability, the greater the risk that is transferred to contracted supplier, which would almost certainly lead to a higher overall price to compensate for the risk. The Company also considered the relative size of its default service customer load and the impact that may have on risk, supplier bid pricing, and overall supplier participation. During DSP IV, the relative sizing of 12- and 24-month FPFR products were about 37 MW (PLC)[2] each tranche, or a total of approximately 112 MW out of a total PLC of 138-140 MW. This value was low, especially when compared to peer Pennsylvania EDCs, which had a tranche size of 70-100 MW,[3] or double that of UGI Electric. Notably, UGI Electric's smaller tranche size could lead to increased supplier risk premiums and lower supplier interest in the product.

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

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

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[2] PLC stands for Peak Load Contribution.

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

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

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

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

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

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

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

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

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

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

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

IV. PROPOSED DSP V PROCURMENT STRATEGY FOR GSR-1

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. To reduce this risk, the Company will expand the FPFR load share, improve the solicitation for FPFR, and continue to leverage the benefits obtained from block supply contracts. UGI Electric is seeking to adjust its block products to eliminate the variability and extend the term of its block products while simultaneously reducing the number of FPFR product types to create a more transparent, less risky suite of default service products. The Company's proposal includes 20 MW of ATC Block in two 10 MW 24-month contracts that will be layered so that a new block product is added annually. The 24-month block products will replace the 24-month FPFR currently implemented in DSP IV. This will provide a stable block supply quantity – 20 MW – for which FPFR suppliers can accurately account, thereby reducing load variance risk in the FPFR product. Shrinking the block size but lengthening the term will increase the FPFR tranche size to approximately 60 MW (from 40 MW in DSP IV), while increasing the total value proposal of the block product for block bidders. Utilizing a 24-month ATC Block is also expected to reduce supplier risk premiums typically seen attached to longer-term FPFR products. It will also reduce the administrative burden associated with the Company's current approach. The longer-term block contract is also more appealing to most suppliers because it provides an increased supply obligation they can layer into their overall portfolio, and scaled up margin.

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

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

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

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

Q. Please describe the concerns regarding PJM capacity pricing.

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

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

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

Q. Please describe the NMB costs.

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

Q. Why is the Company proposing these changes?

A. Taken collectively, these changes aim to remove elements that introduce risk for suppliers where appropriate and practical, which is intended to increase supplier participation and reduce associated product risk premiums without needlessly increasing risks to customers. Most other EDCs in Pennsylvania remove these elements from FPFR contract specifications, so adopting these changes should improve the competitiveness of UGI Electric's FPFR products.

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

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

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

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

Q. Please describe the anticipated spot market activity.

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

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

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

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

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

V. PROPOSED DSP V PROCURMENT STRATEGY FOR GSR-2

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

A. To meet the GSR-2 load requirements during DSP V, the Company will continue to use the hourly procurement methodology that was used in DSP IV. Accordingly, through DSP V, the Company will acquire default service energy for these customers through PJM's real-time hourly spot market. In addition to energy purchases, the Company will be responsible for acquiring any necessary capacity, transmission to UGI Electric's system, ancillary services, congestion management services, AEPS credits, applicable net metering excess generation purchases and such other services or products as necessary to provide default service to the Company's GSR-2 customers.

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

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

In total, GSR-2 customers represent significant volatility and risk for any supplier that would seek to provide UGI with GSR-2 supply. This could result in high risk premiums or little to no supplier participation. In fact, this risk – higher premiums and the potential for customer cross-subsidization – is the foundation for the Commission's determination that EDCs implement a demand split for commercial and industrial customers through the PA PUC Retail Market Investigation.

VI. ANTICIPATED LOAD IMPACTS TO DEFAULT SERVICE DURING DSP V

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

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

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

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

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

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

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

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

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

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

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

A. No. To be clear, this process would only be implemented if FPFR load dropped to a level that could result in higher risk premiums or reduced supplier participation. This change is in fact an attempt to reduce risk and improve competition. Further, any change would have no impact on contracts already in effect. Any FPFR supplier bidding on a future term would be provided information on the reduction in the ATC Block to appropriately incorporate the change into their bid analysis and resulting bid price.

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

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

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

A. Net metering participation in UGI Electric's territory has been, and currently is, relatively low. As of May 2023, the Company had less than 200 customers participating in its net metering program. Exported generation from these customers has likewise been relatively low, resulting in an average of 215,710 kWh of excess customer-generation on UGI Electric's system annually over the last three years that was credited through the net metering program. While the Company had some growth in net metering participation since DSP III, the total growth during DSP IV did not meaningfully impact the Company's default service load and procurement activities.

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

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

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

A. UGI Electric currently has 30 new applications for net metering systems to be installed in the Company's service territory within the next 3 years. Of these 30, 16 installations will have supply peak load impacts under 100 kW that will impact GSR-1, and 14 will have supply peak load impacts greater than 100kW that impact GSR-2. The facilities impacting GSR-1 will provide up to 186kW of generation, whereas the 14 facilities classified as GSR-2 will provide up to 22 MW of generation. All of the inquiries regarding GSR-2 customer-generation facilities have been over the past twelve months. Thus, based on the inquiries received to date, UGI Electric may add as much as 12,000-22,000 kilowatts (12-22 MW) of nameplate capacity in large-scale customer-generation in the next three years in particular. Excess power production from these customer-generators could range between 35,000,000 to 45,000,000 kWh annually. This would result in upward of a 150 to 200 times or more increase in UGI Electric purchases of exported net metered energy over the highest historical activity from existing customer-generation. I note that an anticipated 22 MW of total generation would represent approximately 6% of UGI Electric's total default service load.

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

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

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

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

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

A. The assignment of net metering customers with supply peak load impacts of 100kW or greater to GSR-2 are intended to group similar commercial and industrial customers having similar grid impacts. Large net metering facilities have substantial grid impacts somewhat akin to those associated with large commercial and industrial customers that shop for power supply. As discussed previously, GSR-2 customers have a higher shopping level as compared to GSR-1 customers, and thus more variable impacts on the default service supply portfolio. While net metering is not shopping, large net metering customers have a comparable impact and may choose to move to wholesale market participation. Therefore, the assignment of large net metering customers to the GSR-2 rate group is logical and reasonable. This assignment will appropriately ensure GSR-1 is not negatively impacted.

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

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

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

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

VII. PROPOSED PROCUREMENT SCHEDULE AND BID REQUIREMENTS

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

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

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

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

Q. Who will implement these power supply RFPs?

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

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

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

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

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

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

A. The Company is seeking to maintain the use of a sealed-bid auction process in DSP V. Under this process, prospective suppliers bid what equates to a 'best and final offer' for each product for which they are qualified to bid. Bids will be confidential and not shared with any competitors or other parties outside of the Company and the Commission. The bids received are ranked and the lowest bid is selected, subject to bidders meeting technical requirements and subsequent Commission approval.

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

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

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

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

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

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

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

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

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

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

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

A. At this time, it does not.

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

A. UGI Electric is proposing to incorporate a fixed fee Bid Assurance Collateral amount based upon the product type. For both FPFR and block contracts, prospective bidders will be required to provide $75,000 to qualify to participate in the auction. If a prospective bidder sought to bid on both FPFR and Block products in a single auction, the combined Bid Assurance Collateral amount provided to UGI Electric would be $150,000. Collateral can be in the form of cash or a qualified bank letter of credit. If cash is provided, the Company will not compensate suppliers for interest accrued. The Bid Assurance Collateral provided by participating suppliers will be returned either: (1) immediately following Commission approval of the auction results, for all suppliers not selected, or (2) immediately following Commission approval of the auction results and after selected suppliers have fully executed all agreements. UGI Electric will not require prospective suppliers to provide Bid Assurance Collateral for AEPS RFPs, because the risk exposure is low, the pricing is less susceptible to sudden and significant market volatility, and the Company has a Contingency Plan in place that could be used to secure the needed AECs in the event of a supplier default.

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

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

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

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

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

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

VIII. CONTINGENCY PLANS FOR ENERGY AUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

IX. <u>AEPS COMPLIANCE</u>

Q. Is UGI Electric required to procure AEPS credits?

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

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

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

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

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

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

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[8] See 52 Pa. § Code 54.182.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

X. <u>AGREEMENTS AND FORMS</u>

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

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

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

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

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

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

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

Q. Does this conclude your testimony?

A. Yes.

Exhibit JMR - 1

DAYMARK ENERGY ADVISORS

James M. Rouland

Managing Consultant

Jim works closely with utilities and regulators to advance clean energy initiatives, support wholesale and retail electric procurement, and influence state, regional, and federal regulatory policies. He has broad experience in renewable energy, clean energy RFP development and implementation, transmission and distribution rates and tariff design including performance-based ratemaking, customer programs, and strategic development surrounding state regulatory activities. Jim has testified before state regulatory agencies on issues including wholesale energy procurement, clean energy programs, net energy metering, and time-of-use rates.

SELECTED PROFESSIONAL EXPERIENCE

Clean energy

- Drafted utility company positions, whitepapers, and leadership presentations on multiple legislative, regulatory, and operational topics such as distribution-based alternative rate making mechanisms and implementation, FERC Order 2222 and Order 841 implications and opportunities related to distributed energy resource (DER) integration and grid management, integration of inverter-based resource to support grid operations, community solar program design, renewable energy portfolio standards relationship to clean energy integration, implications and opportunities for nuclear generation subsidies as part of renewable standards, and electric vehicle (EV) and EV-related infrastructure development including rate design and customer program development.
- Managed Rhode Island Energy (RIE) long-term clean energy programs including: RIE's Large Scale Offshore Wind RFP, implementation of RI's Long-Term Contracting Standard projects, qualified facility (QF) contract management, and implementation of the RI Renewable Energy Growth Program plan design, implementation, and open enrollment process.
- Supported development of Corporate Sustainability Report as well as Greenhouse Gas Reports (includes EPRI, EEI, and CDP reports) on behalf of PPL EU and RIE.

Utility rate design

- *PPL EU Services Corporation, Director of Regulatory Policy and Energy Procurement.* Managed PPL EU's Default Service Price-to-Compare rate development, net energy metering cost recovery, and Time-of-Use (TOU) rate program. Managed RIE's Last Resort Service rate development and rate forecasting.

Distribution Programs

- Led utility-side of state Commission Management Audit and Management Effectiveness Investigations. Activities included: interfacing with Commission Auditors, Commission support staff, and business area leads; lead data gathering and data requestion response drafting and issuance; reviewed Commission Staff recommendation reports and developed and issued annual implementation plans.

- Led utility-side of State Commission rate audits including Generation Supply Charge Riders (wholesale power procurements including Time-of-Use and Renewable Energy Credit procurement), Smart Meter Rider (advanced metering infrastructure), universal service rider (low-income and disadvantaged community customers), Act 129 rider (energy efficiency and conservation), net metering, green power option, and the transmission service charge.
- Regulatory oversight, strategy, and design for utility inverter petition (pilot) – development and implementation for initial program. Included selection of customer segment, size and cost analysis of program, intended benefits and KPI development/tracking, and review of reports to Commission before issuance.
- Advanced Metering Infrastructure (fmrly Smart Meter) program policy and regulatory scoping and roll-out. Included strategy development and cost recovery considerations, rider development, and reporting.
    - Work also included implementation of new meter data management systems used for customer data aggregation, ISO market scheduling and settlements, rate and rider calculations, retail and wholesale supplier settlements, zonal tie-outs (settlement of zone load/generation flows), and ICAP and NITS customer tag calculations (installed capacity and transmission tags used for market capacity cost recovery).
- Regulatory oversight, strategy, and design support for electric vehicle make-ready program (pilot).
- Strategy development supporting utility energy efficiency and conservation programs

Distribution rates

- Supported analysis and strategic decision making behind impetus for filing a distribution rate case, including operational (e.g., investments for reliability and resiliency), financial (e.g., kWh sales changes and forecasting, load impacts and adjustments, etc.), and programmatic (e.g., proposed new programs such as changes to net metering rules, customer impact assessments, etc.)
- Research and proposals into alternative ratemaking design opportunities, including historical test year vs. future test year vs. fully projected future test year, and analysis into multiyear rate plans, performance-based ratemaking, formula rates, decoupling, and riders (U.S. utilities and European).
- Strategy behind customer charge, including changes to approach (monthly charge vs. daily charge), and impact to customers.
- Rider analysis and tariff page updates
    - Generation Service Charge – comprehensive analysis of GSC updates and assessments for cost recovery of wholesale energy and associated costs (residential, small commercial & industrial, and large commercial & industrial customers); includes net energy metering rider adjustments and time-of-use rates.
        - Net Energy Metering analysis (distribution) – full retail rate compensation for NEM customers, impact to non-NEM customers (transmission and distribution cost impacts)
        - TOU rate design – development and implementation of various TOU rates; impact analysis and reporting on participating customers; design recommendations to

support EV charging (e.g., peak vs. off-peak vs. super off-peak; seasonal variability; EV charging stand-alone rates)

- Smart metering rider (distribution) – recovery of costs associated with advanced metering infrastructure investments.
- Strategy support behind Distribution Service Improvement Charge (DSIC) (distribution).
- Transmission Service Charge (TSC) impact analysis (through default service rate – price-to-compare; impacts of net metering on TSC cost recovery and over/under collection)

- Support in bidding company facilities (company use) to secure competitive electric supply to reduce costs to customers (shopping versus default service self-supply), which included leads to operating cost assessment and prudency, opportunities for solar PV installations to offset company use and generate customer revenue, and expense reduction measures.
- Worked with rates and accounting team to evaluate various accounting components in support of the distribution rate case filing.
    - Reviewed and provided comments on accounting's technical results of cash working capital assessment
    - Evaluation of uncollectibles and provided guidance for recovery options
    - Reviewed rider mechanisms and provided recommendations for rate design (e.g., supported lead witness preparation and provided supporting analysis behind rate design positions and resulting conclusions, provided strategic and policy guidance to support conclusions)
    - Reviewed and provided supplemental analysis on customer rate schedules
- Reviewed consultant analysis associated with comparison of costs/performance to peers, management effectiveness, customer experience performance, safety performance, merger-synergies, etc.

Transmission rates

- Provided general support for annual updates to the Transmission Formula Rate submissions.
- Transmission peak demand analysis for medium and large commercial & industrial cost recovery
    - Evaluation of customer usage and peak demand by customer rate tariff group.
    - Evaluation of coincidental peak (CP) – 1CP vs 5CP vs 12CP (for example), and winter peak versus summer peak, for both installed capacity (ICAP) and network integration transmission services (NITS).
    - General cost causation analysis > primary focus on commercial and industrial (C&I) customers, with special consideration of seasonal C&I customers and the impact of peak demand allocation and associated cost recovery.

Procurements and portfolios

- *PPL Services Corp, Director, Regulatory Policy and Energy Procurement.* Managed all elements of electricity and electricity-related procurement programs, including: Default Service Energy

Procurement Program for PPL Electric Utilities Corp. (PPL EU), Last Resort Service Procurement Program for Rhode Island Energy (RIE), and Renewable Portfolio Standard and Renewable Energy Credit programs. Also conducted RFPs for long-term offshore wind, and for small and medium scale clean energy projects in Rhode Island. Activities include the design, development, and filing of energy procurement strategic initiative and resulting plans with state utility commissions; leading regulator and stakeholder technical sessions; providing expert testimony in support of proposals; conducting energy, REC, and clean energy auctions and RFPs; supplier management (contracting, invoicing, and communications); wholesale energy settlement and scheduling (through PJM and ISO-NE markets), and rate tariff design and cost recovery.

- Management of wholesale energy procurement (including wholesale supplier contracting)
    - Energy plan design, including product and procurement design analysis (e.g., fixed price full requirements load following transactions, spot market transactions, 24x7 block energy-only transactions, peak vs. off-peak block transactions, optional monthly pricing transactions), evaluation of peer utility programs, market forecasting and auction forecast trending, risk mitigation and hedging strategies.
    - Issuance and implementation of wholesale energy procurement plans (website design, bid evaluation design and implementation, communication plans, bidder presentations, FAQs, etc.)
- Management of supplier and customer settlement and scheduling through ISO, including contract deal entry into ISO systems (e.g., Load Service Entity assignments, bilateral agreements), daily energy market settlements, capacity settlement (ICAP and NITS), ancillary services and billing line item adjustments.
- Management of clean energy RFPs
    - RFP design, including evaluation of regulatory rules and statues, development of procurement approach (terms and conditions, timing, product design, bid details, performance assurance, etc.), document development (RFP process and rules, master agreements, bidding forms),
    - Collaboration with regulatory agencies, bidders, and key stakeholders
    - Supplier contracting (master agreement negotiations, pricing negotiations, quarterly supplier project updates)
    - Rate design and cost recovery (e.g., establishing contract for differences, charge/credit to customers, reconciliation)

Regulatory economics

- *PPL Services Corp, Director, Regulatory Policy and Energy Procurement.* Managed regulatory strategy development for distribution and customer service operations.
- Evaluated legislative and regulatory proposals and policies for impact to business operations and strategy, and customer impacts. Developed analysis defining costs and opportunities on a multitude of topics such as net energy metering, community solar, changes to state renewable portfolio standards, supplier consolidated billing, the purchase of receivables program, utility-implemented shopping programs, electrification initiatives (heat pump, EVs, and commercial

applications), energy storage, DER integration and aggregation, and utility-customer-third party data exchange proposals.

Power system planning

- Wholesale market analysis such as generation adequacy evaluation, modeling of generation dispatch curves, generation interconnection (through ISO) and market impact assessments, Reliability Must Run (RMR) case studies, and ancillary service cost assessments.
- *PPL Electric Utilities Corporation, Supervisor, Settlement & Scheduling Team.* Responsible for energy, capacity and ancillary product market settlements in the PJM territory, all supplier set-up (shopping and wholesale) for PPL service territory, develop and implement customer load profiles, manage customer capacity tag processes, and manage settlement databases.

COMMENT AND TESTIMONY DOCKET NUMBERS

- PPL - M-2020-3023323
- PPL - M-2017-2631527
- PPL - M-2009-2093383
- PPL - L-2014-2404361
- PPL - P-2014-2417907

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc. — Worcester, MA
Managing Consultant — 2023 – *Present*

PPL Services Corp.
Director Regulatory Policy & Energy Procurement — 2023
Senior Manager Regulatory Policy — 2022 – 2023

PPL Electric Utilities Corporation
Regulatory Policy Manager — 2018 – 2022
Supervisor Energy Procurement, Settlement & Scheduling — 2016 – 2018
Supervisor Energy Procurement — 2012 – 2016
Senior Analyst Business Operations — 2009 – 2012

PPL Development Company
Senior Energy & Climate Change Professional — 2008

PPL Environmental Management
Environmental Professional/Lead Auditor — 2005 – 2008

EDUCATION

University of Phoenix — King of Prussia, PA
M.B.A. — 2008

Albright College — Reading, PA

B.S., Environmental Science, B.A., Environmental Policy	2005

Exhibit JMR - H

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

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

Exhibit JMR-3

UGI Utilities Inc. – Electric Division
Default Service Plan V
Exhibit JMR-3

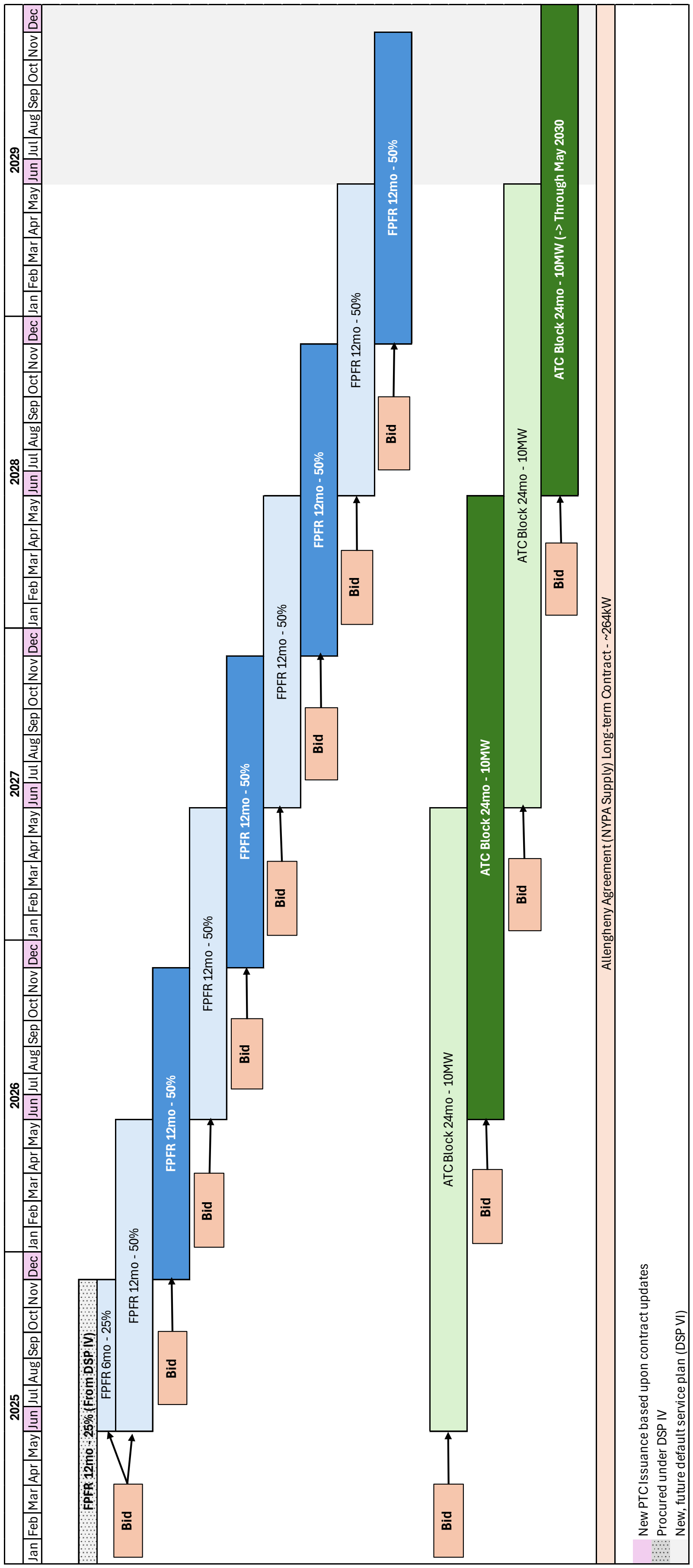


Exhibit JMR-4

AGREEMENT FOR ELECTRIC SERVICE

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

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

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

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

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

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

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

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

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

1. Delivery of Authority Power and Associated Energy

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

2. Inability to Receive the Allocated Power and Energy

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

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

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

4. Company's Individual Liability

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

5. Term of Agreement

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

6. Governing Law

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

7. Regulatory Agency or Court Modification

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

8. Address of parties

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

To: Bargaining Agent

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

To: Company

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

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

Bargaining Agent
Allegheny Electric Cooperative, Inc

(SEAL)

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

Attest:
Laurence V. Bladen Assistant Secretary

UGI Utilities, Inc.

By: R. J. Chaney QCB

(SEAL)

~~Joseph T. Racho, Senior Analyst~~
ROBERT J. CHANEY, PRESIDENT & CEO

Attest: John C. Barney
ASSIST. SEC.

APPENDIX 1

To

AGREEMENT FOR ELECTRIC SERVICE

BETWEEN

ALLEGHENY ELECTRIC COOPERATIVE, INC.
BARGAINING AGENT

AND

UGI UTILITIES, INC.

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

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

ALLEGHENY ELECTRIC COOPERATIVE, INC.

BARGAINING AGENT FOR

COMMONWEALTH OF PENNSYLVANIA

SERVICE TARIFF AEC-1

FIRM POWER AND ASSOCIATED ENERGY

PLUS

INTERRUPTIBLE ENERGY

APPLICABLE:

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

AVAILABILITY

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

CHARACTER OF SERVICE:

Alternating current; 60 hertz; three-phase.

RATE FOR SERVICE (Per Month):

MONTHLY CUSTOMER CHARGE: $180.00

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

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

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

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

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

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

MINIMUM MONTHLY CHARGE:

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

CONTRACT DEMAND:

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

DETERMINATION OF BILLING DEMAND:

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

SPECIAL PROVISIONS:

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

TERMS OF PAYMENT:

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

EFFECTIVE DATE:

January 5, 2004

ALLEGHENY ELECTRIC COOPERATIVE, INC.

SERVICE TARIFF AEC-1

SPECIAL PROVISIONS

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

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

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

B. **Delivery**

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

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

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

C. **Payment**

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

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

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

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

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

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

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

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

D. **Resale of Power and Energy**

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

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

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

E. **Cancellation or Modification**

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

F. **Scheduling Procedures**

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

APPENDIX 1 TO SPECIAL PROVISIONS OF SERVICE TARIFFS

AEC-1 AND AEC-2

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

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

1. Consultant Fees (Legal-Engineering)
2. Administrative/Personnel Costs
3. Miscellaneous Expenditures (Travel, Lodging, etc.)

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

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

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

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

Exhibit JMR - 5

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Charges:

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

    Credits:

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

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

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

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

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

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

   iii. If any issues exist, UGI will contact the Bidder to discuss and rectify the identified issue.
b. Collateral may be in the form of cash or a Letter of Credit.
   i. If bidder choose to utilize cash, UGI will provide wire instructions and will request bid return wire instructions
   ii. If the bidder chooses to utilize a Letter of Credit, UGI will provide a template of terms, including those which may not be adjusted or altered, for review and use by bidder and their banks
c. Bid assurance Collateral will be returned as follows:
   i. To bidders not selected through the competitive solicitation:
      1. Cash: within 2 business days following PUC Decision [DATE]
      2. Letter of Credit: within 3 business days following PUC Decision [DATE]
   ii. To Selected/Winning Bidders as follows:
      1. Cash: within 2 business days following fully executed contract documents.
      2. Letter of Credit: within 3 business days following fully executed contract documents.

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

19. **Energy Requested**

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

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

**Note: the 50% load following obligation is based upon the total GSR-1 default service customer load share after the application of the Around-the-Clock Block ("ATC Block"), energy-only supply contracts. UGI intends to competitively secure 10MW of ATC Block, which will be in effect from June 1, 2025 through May 31, 2027, and an additional 10MW ATC Block in effect from June 1, 2026 through May 31, 2028. This amounts for a total of 20MW of ATC Block staring June 1,* *2026. This ATC Block, or its equivalent, will be maintained throughout the DSP V supply period (i.e. May 31, 2029) through successive procurements of 10MW ATC Block. ATC Block is defined as 24x7 energy-only supply. Any change in ATC Block will be made prospectively only, with such changes communicated to bidders prior to a bid for FPFR supply.*

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

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

Supplier Name	______________________
Contact Person and Phone	______________________
Supply Type	Fixed Price Load Following Full Requirements Service
Delivery Point	[Insert Delivery Point]

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

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

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

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

PJM Qualification Certification Form

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

Signed: Date:

___________________________________ _________________________

Type or Print Name of Officer:

____

Title: _____________________________

Company: _________________________

[Date]

Dear Sir or Madam:

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

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

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

RFP Schedule

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

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

[Insert Link]

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

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

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

[Insert Link]

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

Thank you,

UGI

Exhibit JMR - 6

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

11. Energy Requested

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

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

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

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

Supplier Name ____

Primary Contact Phone ____

Primary Contact E-mail ____

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

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

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

PJM Qualification Certification Form

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

Signed: Date:

__________________________________ ________________________

Type or Print Name of Officer:

____

Title: ____________________________

Company: ________________________

[Date]

Dear Sir or Madam:

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

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

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

RFP Schedule

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

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

[Insert Link]

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

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

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

[Insert Link]

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

Thank you,

UGI

Exhibit JMR - 7

Master Power Purchase & Sale Agreement

Version 2.1 (modified 4/25/00)

MASTER POWER PURCHASE AND SALE AGREEMENT

COVER SHEET

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

Name ("________________" or "Party A")

All Notices:

Street: ______________________________

City: ____________________Zip: ________

Attn: Contract Administration
Phone: ______________________________
Facsimile: ______________________________
Duns: ______________________________
Federal Tax ID Number: ____________________

Invoices:
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

Scheduling:
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

Payments:
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

Wire Transfer:
BNK: ______________________________
ABA: ______________________________
ACCT: ______________________________

Credit and Collections:
Attn: ______________________________
Phone: ______________________________
Facsimile: ______________________________

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

Party B – UGI Utilities, Inc. – Electric Division

All Notices:

Street Address: 1 UGI Drive

City: Denver, PAZip: 17517

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

Invoices:
Attn:______________________________
Phone:______________________________
Facsimile:______________________________

Scheduling:
Attn:______________________________
Phone:______________________________
Facsimile:______________________________

Payments:
Attn:______________________________
Phone:______________________________
Facsimile:______________________________

Wire Transfer:
BNK:.
ABA:______________________________
ACCT:______________________________

Credit and Collections:
Attn:______________________________
Phone:______________________________
Facsimile:______________________________

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

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

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

Article Two

Transaction Terms and Conditions — [X] Optional provision in Section 2.4. If not checked, inapplicable.

Article Four

Remedies for Failure to Deliver or Receive — [X] Accelerated Payment of Damages. If not checked, inapplicable.

Article Five

Events of Default; Remedies

[] Cross Default for Party A:

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

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

[] Cross Default for Party B:

[] Party B:__________________ Cross Default Amount $_________

[] Other Entity:_______________ Cross Default Amount $_________

5.6 Closeout Setoff

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

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

[] Option C (No Setoff)

Article 8

Credit and Collateral Requirements

8.1 Party A Credit Protection:

(a) Financial Information:

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

(b) Credit Assurances:

[] Not Applicable
[X] Applicable

(c) Collateral Threshold:

[] Not Applicable
[X] Applicable

If applicable, complete the following:

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

Party B Independent Amount: $ See Collateral Annex attached hereto

Party B Rounding Amount: $ See Collateral Annex attached hereto

(d) Downgrade Event:

[X] Not Applicable
[] Applicable

If applicable, complete the following:

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

[] Other:
Specify:____

(e) Guarantor for Party B:______________________________________

Guarantee Amount:______________________________________

8.2 <u>Party B Credit Protection</u>:

(a) Financial Information:

[X] Option A
[X] Option B Specify: <u>Guarantor, if applicable</u>
[] Option C Specify: ________________
<u>[X] Option D</u>

(b) Credit Assurances:

[] Not Applicable
[X] Applicable

(c) Collateral Threshold:

[] Not Applicable
[X] Applicable

If applicable, complete the following:

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

Party A Independent Amount: See Collateral Annex attached hereto

Party A Rounding Amount: See Collateral Annex attached hereto

(d) Downgrade Event:

[X] Not Applicable
[] Applicable

If applicable, complete the following:

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

[] Other:
Specify:____

(e) Guarantor for Party A: To be decided

Guarantee Amount: To be decided

Article 10

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

Schedule M

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

Other Changes: Yes

Article One: General Definitions

The following definitions are amended as set forth below:

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

2. Section 1.46 is deleted in its entirety

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

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

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

Article Two: Transaction Terms and Conditions

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

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

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

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

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

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

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

Article Five: Events of Default; Remedies

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

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

New Subsection 5.1 (i) is added as follows:

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

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

Article Six: Payment and Netting

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

Article Seven: Limitations

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

Article Eight: Credit and Collateral Requirements

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

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

Article Ten: Miscellaneous

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

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

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

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

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

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

.

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

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

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

GENERAL TERMS AND CONDITIONS

ARTICLE ONE: GENERAL DEFINITIONS

1.1 "Affiliate" means, with respect to any person, any other person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

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

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

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

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

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

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

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

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

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

1.11 "Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace a Terminated Transaction; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of a Transaction.

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

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

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

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

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

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

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

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

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

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

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

1.23 "Force Majeure" means an event or circumstance which prevents one Party from performing its obligations under one or more Transactions, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (i) the loss of Buyer's markets; (ii) Buyer's inability economically to use or resell the Product purchased hereunder; (iii) the loss or failure of Seller's supply; or (iv) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred. The applicability of Force Majeure to the Transaction is governed by the terms of the Products and Related Definitions contained in Schedule P.

1.24 "Gains" means, with respect to any Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of a Terminated Transaction, determined in a commercially reasonable manner.

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

1.26 "Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

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

1.28 "Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of a Terminated Transaction, determined in a commercially reasonable manner.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ARTICLE TWO: TRANSACTION TERMS AND CONDITIONS

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

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

2.3 Confirmation. Seller may confirm a Transaction by forwarding to Buyer by facsimile within three (3) Business Days after the Transaction is entered into a confirmation ("Confirmation") substantially in the form of Exhibit A. If Buyer objects to any term(s) of such Confirmation, Buyer shall notify Seller in writing of such objections within two (2) Business Days of Buyer's receipt thereof, failing which Buyer shall be deemed to have accepted the terms as sent. If Seller fails to send a Confirmation within three (3) Business Days after the Transaction is entered into, a Confirmation substantially in the form of Exhibit A, may be forwarded by Buyer to Seller. If Seller objects to any term(s) of such Confirmation, Seller shall notify Buyer of such objections within two (2) Business Days of Seller's receipt thereof, failing which Seller shall be deemed to have accepted the terms as sent. If Seller and Buyer each send a Confirmation and neither Party objects to the other Party's Confirmation within two (2) Business Days of receipt, Seller's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation, unless (i) Seller's Confirmation was sent more than three (3) Business Days after the Transaction was entered into and (ii) Buyer's Confirmation was sent prior to Seller's Confirmation, in which case Buyer's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation. Failure by either Party to send or either Party to return an executed Confirmation or any objection by either Party shall not invalidate the Transaction agreed to by the Parties.

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

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

ARTICLE THREE: OBLIGATIONS AND DELIVERIES

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

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

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

ARTICLE FOUR: REMEDIES FOR FAILURE TO DELIVER/RECEIVE

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

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

ARTICLE FIVE: EVENTS OF DEFAULT; REMEDIES

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

(a) the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within three (3) Business Days after written notice;

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

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

(d) such Party becomes Bankrupt;

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

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

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

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

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

 (ii) the failure of a Guarantor to make any payment required or to perform any other material covenant or obligation in any guaranty made in connection with this Agreement and such failure shall not be remedied within three (3) Business Days after written notice;

(iii) a Guarantor becomes Bankrupt;

(iv) the failure of a Guarantor's guaranty to be in full force and effect for purposes of this Agreement (other than in accordance with its terms) prior to the satisfaction of all obligations of such Party under each Transaction to which such guaranty shall relate without the written consent of the other Party; or

(v) a Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of any guaranty.

5.2 Declaration of an Early Termination Date and Calculation of Settlement Amounts. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party (the "Non-Defaulting Party") shall have the right (i) to designate a day, no earlier than the day such notice is effective and no later than 20 days after such notice is effective, as an early termination date ("Early Termination Date") to accelerate all amounts owing between the Parties and to liquidate and terminate all, but not less than all, Transactions (each referred to as a "Terminated Transaction") between the Parties, (ii) withhold any payments due to the Defaulting Party under this Agreement and (iii) suspend performance. The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for each such Terminated Transaction as of the Early Termination Date (or, to the extent that in the reasonable opinion of the Non-Defaulting Party certain of such Terminated Transactions are commercially impracticable to liquidate and terminate or may not be liquidated and terminated under applicable law on the Early Termination Date, as soon thereafter as is reasonably practicable).

5.3 Net Out of Settlement Amounts. The Non-Defaulting Party shall aggregate all Settlement Amounts into a single amount by: netting out (a) all Settlement Amounts that are due to the Defaulting Party, plus, at the option of the Non-Defaulting Party, any cash or other form of security then available to the Non-Defaulting Party pursuant to Article Eight, plus any or all other amounts due to the Defaulting Party under this Agreement against (b) all Settlement Amounts that are due to the Non-Defaulting Party, plus any or all other amounts due to the Non-Defaulting Party under this Agreement, so that all such amounts shall be netted out to a single liquidated amount (the "Termination Payment") payable by one Party to the other. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.

5.4 Notice of Payment of Termination Payment. As soon as practicable after a liquidation, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Party that owes it within two (2) Business Days after such notice is effective.

5.5 Disputes With Respect to Termination Payment. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within two (2) Business Days of receipt of Non-Defaulting Party's calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute; provided, however, that if the Termination Payment is due from the Defaulting Party, the Defaulting Party shall first transfer Performance Assurance to the Non-Defaulting Party in an amount equal to the Termination Payment.

5.6 Closeout Setoffs.

Option A: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party to the Non-Defaulting Party under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option B: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party or any of its Affiliates to the Non-Defaulting Party or any of its Affiliates under any other agreements, instruments or undertakings between the Defaulting Party or any of its Affiliates and the Non-Defaulting Party or any of its Affiliates and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option C: Neither Option A nor B shall apply.

5.7 Suspension of Performance. Notwithstanding any other provision of this Master Agreement, if (a) an Event of Default or (b) a Potential Event of Default shall have occurred and be continuing, the Non-Defaulting Party, upon written notice to the Defaulting Party, shall have the right (i) to suspend performance under any or all Transactions; provided, however, in no event shall any such suspension continue for longer than ten (10) NERC Business Days with respect to any single Transaction unless an early Termination Date shall have been declared and notice thereof pursuant to Section 5.2 given, and (ii) to the extent an Event of Default shall have occurred and be continuing to exercise any remedy available at law or in equity.

ARTICLE SIX: PAYMENT AND NETTING

6.1 Billing Period. Unless otherwise specifically agreed upon by the Parties in a Transaction, the calendar month shall be the standard period for all payments under this Agreement (other than Termination Payments and, if "Accelerated Payment of Damages" is specified by the Parties in the Cover Sheet, payments pursuant to Section 4.1 or 4.2 and Option premium payments pursuant to Section 6.7). As soon as practicable after the end of each month, each Party will render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding month.

6.2 Timeliness of Payment. Unless otherwise agreed by the Parties in a Transaction, all invoices under this Master Agreement shall be due and payable in accordance with each Party's invoice instructions on or before the later of the twentieth (20th) day of each month, or tenth (10th) day after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day. Each Party will make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any amounts not paid by the due date will be deemed delinquent and will accrue interest at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

6.3 Disputes and Adjustments of Invoices. A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within two (2) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 6.3 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the month during which performance of a Transaction occurred, the right to payment for such performance is waived.

6.4 Netting of Payments. The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing to each other on the same date pursuant to all Transactions through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Master Agreement, including any related damages calculated pursuant to Article Four (unless one of the Parties elects to accelerate payment of such amounts as permitted by Article Four), interest, and payments or credits, shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it.

6.5 Payment Obligation Absent Netting. If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, including, but not limited to, any related damage amounts calculated pursuant to Article Four, interest, and payments or credits, that Party shall pay such sum in full when due.

6.6 Security. Unless the Party benefiting from Performance Assurance or a guaranty notifies the other Party in writing, and except in connection with a liquidation and termination in accordance with Article Five, all amounts netted pursuant to this Article Six shall not take into account or include any Performance Assurance or guaranty which may be in effect to secure a Party's performance under this Agreement.

6.7 Payment for Options. The premium amount for the purchase of an Option shall be paid within two (2) Business Days of receipt of an invoice from the Option Seller. Upon exercise of an Option, payment for the Product underlying such Option shall be due in accordance with Section 6.1.

6.8 Transaction Netting. If the Parties enter into one or more Transactions, which in conjunction with one or more other outstanding Transactions, constitute Offsetting Transactions, then all such Offsetting Transactions may by agreement of the Parties, be netted into a single Transaction under which:

(a) the Party obligated to deliver the greater amount of Energy will deliver the difference between the total amount it is obligated to deliver and the total amount to be delivered to it under the Offsetting Transactions, and

(b) the Party owing the greater aggregate payment will pay the net difference owed between the Parties.

Each single Transaction resulting under this Section shall be deemed part of the single, indivisible contractual arrangement between the parties, and once such resulting Transaction occurs, outstanding obligations under the Offsetting Transactions which are satisfied by such offset shall terminate.

ARTICLE SEVEN: LIMITATIONS

7.1 Limitation of Remedies, Liability and Damages. EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR

OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE EIGHT: CREDIT AND COLLATERAL REQUIREMENTS

8.1 Party A Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.1(a) is specified on the Cover Sheet, Section 8.l(a) Option C shall apply exclusively. If none of Sections 8.1(b), 8.1(c) or 8.1(d) are specified on the Cover Sheet, Section 8.1(b) shall apply exclusively.

(a) Financial Information. Option A: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party B's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of Party B's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as Party B diligently pursues the preparation, certification and delivery of the statements.

Option B: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party A may request from Party B the information specified in the Cover Sheet.

(b) Credit Assurances. If Party A has reasonable grounds to believe that Party B's creditworthiness or performance under this Agreement has become unsatisfactory, Party A will provide Party B with written notice requesting Performance Assurance in an amount determined by Party A in a commercially reasonable manner. Upon receipt of such notice Party B shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party A. In the event that Party B fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party A plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold, then Party A, on any Business Day, may request that Party B provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold (rounding upwards for any fractional amount to the next Party B Rounding Amount) ("Party B Performance Assurance"), less any Party B Performance Assurance already posted with Party A. Such Party B Performance Assurance shall be delivered to Party A within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party B, at its sole cost, may request that such Party B Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party B's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party B Rounding Amount). In the event that Party B fails to provide Party B Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.1(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party A as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party B to Party A, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party B, then Party A may require Party B to provide Performance Assurance in an amount determined by Party A in a commercially reasonable manner. In the event Party B shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default shall be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party B shall deliver to Party A, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party A.

8.2 Party B Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.2(a) is specified on the Cover Sheet, Section 8.2(a) Option C shall apply exclusively. If none of Sections 8.2(b), 8.2(c) or 8.2(d) are specified on the Cover Sheet, Section 8.2(b) shall apply exclusively.

(a) Financial Information. Option A: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party A's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of such Party's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as such Party diligently pursues the preparation, certification and delivery of the statements.

Option B: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party B may request from Party A the information specified in the Cover Sheet.

(b) Credit Assurances. If Party B has reasonable grounds to believe that Party A's creditworthiness or performance under this Agreement has become unsatisfactory, Party B will provide Party A with written notice requesting Performance Assurance in an amount determined by Party B in a commercially reasonable manner. Upon receipt of such notice Party A shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party B. In the event that Party A fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party B plus Party A's Independent Amount, if any, exceeds the Party A Collateral Threshold, then Party B, on any Business Day, may request that Party A provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party A's Independent Amount, if any, exceeds the Party A Collateral

Threshold (rounding upwards for any fractional amount to the next Party A Rounding Amount) ("Party A Performance Assurance"), less any Party A Performance Assurance already posted with Party B. Such Party A Performance Assurance shall be delivered to Party B within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party A, at its sole cost, may request that such Party A Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party A's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party A Rounding Amount). In the event that Party A fails to provide Party A Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.2(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party B as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party A to Party B, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party A, then Party B may require Party A to provide Performance Assurance in an amount determined by Party B in a commercially reasonable manner. In the event Party A shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party A shall deliver to Party B, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party B.

Option D: Party B may request from Party A the information specified in the Cover Sheet, as defined below.

(a) Performance Assurances. Party B requires that Party A provide Performance Assurance Collateral in the amount of $175,000 for Fixed Price Load Following Full Requirements contracts and $100,000 for block contracts. The Performance Assurance Collateral is required following award of a supply, commensurate with the product awarded. Collateral can be in the form of cash or a bank letter of credit. If cash is provided, the Company may compensate Party A for interest accrued and the relevant interest rate as defined by Party B. The Performance Assurance Collateral provided by Party A will be returned at the conclusion of the product supply term as defined in the contract unless otherwise agreed upon by between Party A and Party B.

8.3 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent either or both Parties deliver Performance Assurance hereunder, each Party (a "Pledgor") hereby grants to the other Party (the "Secured Party") a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, such Secured Party, and each Party agrees to take such action as the other Party reasonably requires in order to perfect the Secured Party's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, the Non-Defaulting Party may do any one or more of the following: (i) exercise any of the rights and remedies of a Secured Party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Defaulting Party in the possession of the Non-Defaulting Party or its agent; (iii) draw on any outstanding Letter of Credit issued for its benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Secured Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under the Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

ARTICLE NINE: GOVERNMENTAL CHARGES

9.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Master Agreement in accordance with the intent of the parties to minimize all taxes, so long as neither Party is materially adversely affected by such efforts.

9.2 Governmental Charges. Seller shall pay or cause to be paid all taxes imposed by any government authority ("Governmental Charges") on or with respect to the Product or a Transaction arising prior to the Delivery Point. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or a Transaction at and from the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of the Product and are, therefore, the responsibility of the Seller). In the event Seller is required by law or regulation to remit or pay Governmental Charges which are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Governmental Charges. If Buyer is required by law or regulation to remit or pay Governmental Charges which are Seller's responsibility hereunder, Buyer may deduct the amount of any such Governmental Charges from the sums due to Seller under Article 6 of this Agreement. Nothing shall obligate or cause a Party to pay or be liable to pay any Governmental Charges for which it is exempt under the law.

ARTICLE TEN: MISCELLANEOUS

10.1 Term of Master Agreement. The term of this Master Agreement shall commence on the Effective Date and shall remain in effect until terminated by either Party upon (thirty) 30 days' prior written notice; provided, however, that such termination shall not affect or excuse the performance of either Party under any provision of this Master Agreement that by its terms survives any such termination and, provided further, that this Master Agreement and any other documents executed and delivered hereunder shall remain in effect with respect to the Transaction(s) entered into prior to the effective date of such termination until both Parties have fulfilled all of their obligations with respect to such Transaction(s), or such Transaction(s) that have been terminated under Section 5.2 of this Agreement.

10.2 Representations and Warranties. On the Effective Date and the date of entering into each Transaction, each Party represents and warrants to the other Party that:

(i) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(ii) it has all regulatory authorizations necessary for it to legally perform its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(iii) the execution, delivery and performance of this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(iv) this Master Agreement, each Transaction (including any Confirmation accepted in accordance with Section 2.3), and each other document executed and delivered in accordance with this Master Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms; subject to any Equitable Defenses.

(v) it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

(vi) there is not pending or, to its knowledge, threatened against it or any of its Affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(vii) no Event of Default or Potential Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(viii) it is acting for its own account, has made its own independent decision to enter into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) and as to whether this Master Agreement and each such Transaction (including any Confirmation accepted in accordance with Section 2.3) is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(ix) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code;

(x) it has entered into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) in connection with the conduct of its business and it has the capacity or ability to make or take delivery of all Products referred to in the Transaction to which it is a Party;

(xi) with respect to each Transaction (including any Confirmation accepted in accordance with Section 2.3) involving the purchase or sale of a Product or an Option, it is a producer, processor, commercial user or merchant handling the Product, and it is entering into such Transaction for purposes related to its business as such; and

(xii) the material economic terms of each Transaction are subject to individual negotiation by the Parties.

10.3 Title and Risk of Loss. Title to and risk of loss related to the Product shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it will deliver to Buyer the Quantity of the Product free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

10.4 Indemnity. Each Party shall indemnify, defend and hold harmless the other Party from and against any Claims arising from or out of any event, circumstance, act or incident first occurring or existing during the period when control and title to Product is vested in such Party as provided in Section 10.3. Each Party shall indemnify, defend and hold harmless the other Party against any Governmental Charges for which such Party is responsible under Article Nine.

10.5 Assignment. Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent may be withheld in the exercise of its sole discretion; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign this Agreement to an affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (iii) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

10.6 Governing Law. THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

10.7 Notices. All notices, requests, statements or payments shall be made as specified in the Cover Sheet. Notices (other than scheduling requests) shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight United States mail or courier shall be effective on the next Business Day after it was sent. A Party may change its addresses by providing notice of same in accordance herewith.

10.8 General. This Master Agreement (including the exhibits, schedules and any written supplements hereto), the Party A Tariff, if any, the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmation accepted in accordance with Section 2.3) constitute the entire agreement between the Parties relating to the subject matter. Notwithstanding the foregoing, any collateral, credit support or margin agreement or similar arrangement between the Parties shall, upon designation by the Parties, be deemed part of this Agreement and shall be incorporated herein by reference. This Agreement shall be considered for all purposes as prepared through the joint efforts of the parties and shall not be construed against one party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. Except to the extent herein provided for, no amendment or modification to this Master Agreement shall be enforceable unless reduced to writing and executed by both Parties. Each Party agrees if it seeks to amend any applicable wholesale power sales tariff during the term of this Agreement, such amendment will not in any way affect outstanding Transactions under this Agreement without the prior written consent of the other Party. Each Party further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement. This Agreement shall not impart any rights enforceable by any third party (other than a permitted successor or assignee bound to this Agreement). Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change (individually or collectively, such events referred to as "Regulatory Event") will not otherwise affect the remaining lawful obligations that arise under this Agreement; and provided, further, that if a Regulatory Event occurs, the Parties shall use their best efforts to reform this Agreement in order to give effect to the original intention of the Parties. The term "including" when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only. All indemnity and audit rights shall survive the termination of this Agreement for twelve (12) months. This Agreement shall be binding on each Party's successors and permitted assigns.

10.9 Audit. Each Party has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Master Agreement. If requested, a Party shall provide to the other Party statements evidencing the Quantity delivered at the Delivery Point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

10.10 Forward Contract. The Parties acknowledge and agree that all Transactions constitute "forward contracts" within the meaning of the United States Bankruptcy Code.

10.11 Confidentiality. If the Parties have elected on the Cover Sheet to make this Section 10.11 applicable to this Master Agreement, neither Party shall disclose the terms or conditions of a Transaction under this Master Agreement to a third party (other than the Party's employees, lenders, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area or independent system operator rule or in connection with any court or regulatory proceeding; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation.

SCHEDULE M

(THIS SCHEDULE IS INCLUDED IF THE APPROPRIATE BOX ON THE COVER SHEET IS MARKED INDICATING A PARTY IS A GOVERNMENTAL ENTITY OR PUBLIC POWER SYSTEM)

A. The Parties agree to add the following definitions in Article One.

"Act" means ______________________________.[1]

"Governmental Entity or Public Power System" means a municipality, county, governmental board, public power authority, public utility district, joint action agency, or other similar political subdivision or public entity of the United States, one or more States or territories or any combination thereof.

"Special Fund" means a fund or account of the Governmental Entity or Public Power System set aside and or pledged to satisfy the Public Power System's obligations hereunder out of which amounts shall be paid to satisfy all of the Public Power System's obligations under this Master Agreement for the entire Delivery Period.

B. The following sentence shall be added to the end of the definition of "Force Majeure" in Article One.

If the Claiming Party is a Governmental Entity or Public Power System, Force Majeure does not include any action taken by the Governmental Entity or Public Power System in its governmental capacity.

C. The Parties agree to add the following representations and warranties to Section 10.2:

Further and with respect to a Party that is a Governmental Entity or Public Power System, such Governmental Entity or Public Power System represents and warrants to the other Party continuing throughout the term of this Master Agreement, with respect to this Master Agreement and each Transaction, as follows: (i) all acts necessary to the valid execution, delivery and performance of this Master Agreement, including without limitation, competitive bidding, public notice, election, referendum, prior appropriation or other required procedures has or will be taken and performed as required under the Act and the Public Power System's ordinances, bylaws or other regulations, (ii) all persons making up the governing body of Governmental Entity or Public Power System are the duly elected or appointed incumbents in their positions and hold such

[1] Cite the state enabling and other relevant statutes applicable to Governmental Entity or Public Power System.

positions in good standing in accordance with the Act and other applicable law, (iii) entry into and performance of this Master Agreement by Governmental Entity or Public Power System are for a proper public purpose within the meaning of the Act and all other relevant constitutional, organic or other governing documents and applicable law, (iv) the term of this Master Agreement does not extend beyond any applicable limitation imposed by the Act or other relevant constitutional, organic or other governing documents and applicable law, (v) the Public Power System's obligations to make payments hereunder are unsubordinated obligations and such payments are (a) operating and maintenance costs (or similar designation) which enjoy first priority of payment at all times under any and all bond ordinances or indentures to which it is a party, the Act and all other relevant constitutional, organic or other governing documents and applicable law or (b) otherwise not subject to any prior claim under any and all bond ordinances or indentures to which it is a party, the Act and all other relevant constitutional, organic or other governing documents and applicable law and are available without limitation or deduction to satisfy all Governmental Entity or Public Power System' obligations hereunder and under each Transaction or (c) are to be made solely from a Special Fund, (vi) entry into and performance of this Master Agreement and each Transaction by the Governmental Entity or Public Power System will not adversely affect the exclusion from gross income for federal income tax purposes of interest on any obligation of Governmental Entity or Public Power System otherwise entitled to such exclusion, and (vii) obligations to make payments hereunder do not constitute any kind of indebtedness of Governmental Entity or Public Power System or create any kind of lien on, or security interest in, any property or revenues of Governmental Entity or Public Power System which, in either case, is proscribed by any provision of the Act or any other relevant constitutional, organic or other governing documents and applicable law, any order or judgment of any court or other agency of government applicable to it or its assets, or any contractual restriction binding on or affecting it or any of its assets.

D. The Parties agree to add the following sections to Article Three:

Section 3.4 Public Power System's Deliveries. On the Effective Date and as a condition to the obligations of the other Party under this Agreement, Governmental Entity or Public Power System shall provide the other Party hereto (i) certified copies of all ordinances, resolutions, public notices and other documents evidencing the necessary authorizations with respect to the execution, delivery and performance by Governmental Entity or Public Power System of this Master Agreement and (ii) an opinion of counsel for Governmental Entity or Public Power System, in form and substance reasonably satisfactory to the Other Party, regarding the validity, binding effect and enforceability of this Master

Agreement against Governmental Entity or Public Power System in respect of the Act and all other relevant constitutional organic or other governing documents and applicable law.

Section 3.5 No Immunity Claim. Governmental Entity or Public Power System warrants and covenants that with respect to its contractual obligations hereunder and performance thereof, it will not claim immunity on the grounds of sovereignty or similar grounds with respect to itself or its revenues or assets from (a) suit, (b) jurisdiction of court (including a court located outside the jurisdiction of its organization), (c) relief by way of injunction, order for specific performance or recovery of property, (d) attachment of assets, or (e) execution or enforcement of any judgment.

E. If the appropriate box is checked on the Cover Sheet, as an alternative to selecting one of the options under Section 8.3, the Parties agree to add the following section to Article Three:

Section 3.6 Governmental Entity or Public Power System Security. With respect to each Transaction, Governmental Entity or Public Power System shall either (i) have created and set aside a Special Fund or (ii) upon execution of this Master Agreement and prior to the commencement of each subsequent fiscal year of Governmental Entity or Public Power System during any Delivery Period, have obtained all necessary budgetary approvals and certifications for payment of all of its obligations under this Master Agreement for such fiscal year; any breach of this provision shall be deemed to have arisen during a fiscal period of Governmental Entity or Public Power System for which budgetary approval or certification of its obligations under this Master Agreement is in effect and, notwithstanding anything to the contrary in Article Four, an Early Termination Date shall automatically and without further notice occur hereunder as of such date wherein Governmental Entity or Public Power System shall be treated as the Defaulting Party. Governmental Entity or Public Power System shall have allocated to the Special Fund or its general funds a revenue base that is adequate to cover Public Power System's payment obligations hereunder throughout the entire Delivery Period.

F. If the appropriate box is checked on the Cover Sheet, the Parties agree to add the following section to Article Eight:

Section 8.4 Governmental Security. As security for payment and performance of Public Power System's obligations hereunder, Public Power System hereby pledges, sets over, assigns and grants to the other Party a security interest in all of Public Power System's right, title and interest in and to [specify collateral].

G. The Parties agree to add the following sentence at the end of Section 10.6 - Governing Law:

> NOTWITHSTANDING THE FOREGOING, IN RESPECT OF THE APPLICABILITY OF THE ACT AS HEREIN PROVIDED, THE LAWS OF THE STATE OF ________________[2] SHALL APPLY.

[2] Insert relevant state for Governmental Entity or Public Power System.

SCHEDULE P: PRODUCTS AND RELATED DEFINITIONS

"Ancillary Services" means any of the services identified by a Transmission Provider in its transmission tariff as "ancillary services" including, but not limited to, regulation and frequency response, energy imbalance, operating reserve-spinning and operating reserve-supplemental, as may be specified in the Transaction.

"Capacity" has the meaning specified in the Transaction.

"Capacity Price" means the price, as set by PJM (unless defined or adjusted by Party B), that aligns with a specific PJM planning year spanning June through May, typically comprised of a Base Residual Auction (BRA) and up to three Incremental Auctions for which a price for Capacity is specific to a utility zone.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in megawatt hours.

"Energy Price" means the fixed $/MWh value for which Party A is compensated by Party B for supply rendered in association with the contract terms. This value shall be used in reference to either Fixed Price Load Following Full Requirements (FPFR) contracts or Around-the-Clock Block (ATC Block) supply contracts. For FPFR contracts, this value shall be inclusive of energy, capacity, transmission (other than NMB charges and credits which are the responsibility of Party B), ancillary services, and Alternative Energy Credits for compliance with the AEPS Act, associated transmission system losses, congestion management costs, and other such products and services that are required. In the event a Capacity Price is not available or otherwise final, Party B will supply Party A with guidance on the Capacity Price to be used. This newly defined Capacity Price will also be used in bill between Party A and Party B. For ATC Block contracts, this value shall be inclusive of energy only.

"Firm (LD)" means, with respect to a Transaction, that either Party shall be relieved of its obligations to sell and deliver or purchase and receive without liability only to the extent that, and for the period during which, such performance is prevented by Force Majeure. In the absence of Force Majeure, the Party to which performance is owed shall be entitled to receive from the Party which failed to deliver/receive an amount determined pursuant to Article Four.

"Firm Transmission Contingent - Contract Path" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product in the case of the Seller from the generation source to the Delivery Point or in the case of the Buyer from the Delivery Point to the ultimate sink, and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This contingency shall excuse performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary.

"Firm Transmission Contingent - Delivery Point" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission to the Delivery Point (in the case of Seller) or from the Delivery Point (in the case of Buyer) for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product, in the case of the Seller, to be delivered to the Delivery Point or, in the case of Buyer, to be received at the Delivery Point and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This transmission contingency excuses performance for the duration of the interruption or curtailment, notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary. Interruptions or curtailments of transmission other than the transmission either immediately to or from the Delivery Point shall not excuse performance

"Firm (No Force Majeure)" means, with respect to a Transaction, that if either Party fails to perform its obligation to sell and deliver or purchase and receive the Product, the Party to which performance is owed shall be entitled to receive from the Party which failed to perform an amount determined pursuant to Article Four. Force Majeure shall not excuse performance of a Firm (No Force Majeure) Transaction.

"Into ______________ (the "Receiving Transmission Provider"), Seller's Daily Choice" means that, in accordance with the provisions set forth below, (1) the Product shall be scheduled and delivered to an interconnection or interface ("Interface") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which Interface, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area; and (2) Seller has the right on a daily prescheduled basis to designate the Interface where the Product shall be delivered. An "Into" Product shall be subject to the following provisions:

1. Prescheduling and Notification. Subject to the provisions of Section 6, not later than the prescheduling deadline of 11:00 a.m. CPT on the Business Day before the next delivery day or as otherwise agreed to by Buyer and Seller, Seller shall notify Buyer ("Seller's Notification") of Seller's immediate upstream counterparty and the Interface (the "Designated Interface") where Seller shall deliver the Product for the next delivery day, and Buyer shall notify Seller of Buyer's immediate downstream counterparty.

2. Availability of "Firm Transmission" to Buyer at Designated Interface; "Timely Request for Transmission," "ADI" and "Available Transmission." In determining availability to Buyer of next-day firm transmission ("Firm Transmission") from the Designated Interface, a "Timely Request for Transmission" shall mean a properly completed request for Firm Transmission made by Buyer in accordance with the controlling tariff procedures, which request shall be submitted to the Receiving Transmission Provider no later than 30 minutes after delivery of Seller's Notification, provided, however, if the Receiving Transmission Provider is not accepting requests for Firm Transmission at the time of Seller's Notification, then such request by Buyer shall be made within 30 minutes of the time when the Receiving Transmission Provider first opens thereafter for purposes of accepting requests for Firm Transmission.

Pursuant to the terms hereof, delivery of the Product may under certain circumstances be redesignated to occur at an Interface other than the Designated Interface (any such alternate designated interface, an "ADI") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which ADI, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area using either firm or non-firm transmission, as available on a day-ahead or hourly basis (individually or collectively referred to as "Available Transmission") within the Receiving Transmission Provider's transmission system.

3. Rights of Buyer and Seller Depending Upon Availability of/Timely Request for Firm Transmission.

A. Timely Request for Firm Transmission made by Buyer, Accepted by the Receiving Transmission Provider and Purchased by Buyer. If a Timely Request for Firm Transmission is made by Buyer and is accepted by the Receiving Transmission Provider and Buyer purchases such Firm Transmission, then Seller shall deliver and Buyer shall receive the Product at the Designated Interface.

i. If the Firm Transmission purchased by Buyer within the Receiving Transmission Provider's transmission system from the Designated Interface ceases to be available to Buyer for any reason, or if Seller is unable to deliver the Product at the Designated Interface for any reason except Buyer's non-performance, then at Seller's choice from among the following, Seller shall: (a) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, require Buyer to purchase such Firm Transmission from such ADI, and schedule and deliver the affected portion of the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, or (b) require Buyer to purchase non-firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by Seller, or (c) to the extent firm transmission is available on an hourly basis, require Buyer to purchase firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of such hourly firm transmission from the Designated Interface or an ADI designated by Seller.

ii. If the Available Transmission utilized by Buyer as required by Seller pursuant to Section 3A(i) ceases to be available to Buyer for any reason, then Seller shall again have those alternatives stated in Section 3A(i) in order to satisfy its obligations.

iii. Seller's obligation to schedule and deliver the Product at an ADI is subject to Buyer's obligation referenced in Section 4B to cooperate reasonably therewith. If Buyer and Seller cannot complete the scheduling and/or delivery at an ADI, then Buyer shall be deemed to have satisfied its receipt obligations to Seller and Seller shall be deemed to have failed its delivery obligations to Buyer, and Seller shall be liable to Buyer for amounts determined pursuant to Article Four.

iv. In each instance in which Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI pursuant to Sections 3A(i) or (ii), and Firm Transmission had been purchased by both Seller and Buyer into and within the Receiving Transmission Provider's transmission system as to the scheduled delivery which could not be completed as a result of the interruption or curtailment of such Firm Transmission, Buyer and Seller shall bear their respective transmission expenses and/or associated congestion charges incurred in connection with efforts to complete delivery by such alternative scheduling and delivery arrangements. In any instance except as set forth in the immediately preceding sentence, Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI under Sections 3A(i) or (ii), Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with such alternative scheduling arrangements.

B. Timely Request for Firm Transmission Made by Buyer but Rejected by the Receiving Transmission Provider. If Buyer's Timely Request for Firm Transmission is rejected by the Receiving Transmission Provider because of unavailability of Firm Transmission from the Designated Interface, then Buyer shall notify Seller within 15 minutes after receipt of the Receiving Transmission Provider's notice of rejection ("Buyer's Rejection Notice"). If Buyer timely notifies Seller of such unavailability of Firm Transmission from the Designated Interface, then Seller shall be obligated either (1) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, to require Buyer to purchase (at Buyer's own expense) such Firm Transmission from such ADI and schedule and deliver the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, and thereafter the provisions in Section 3A shall apply, or (2) to require Buyer to purchase (at Buyer's own expense) non-firm transmission, and schedule and deliver the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by the Seller, in which case Seller shall bear the risk of interruption or curtailment of the non-firm transmission; provided, however, that if the non-firm transmission is interrupted or curtailed or if Seller is unable to deliver the Product for any reason, Seller shall have the right to schedule and deliver the Product to another ADI in order to satisfy its delivery obligations, in which case Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with Seller's inability to deliver the Product as originally prescheduled. If Buyer fails to timely notify Seller of the unavailability of Firm Transmission, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface, and the provisions of Section 3D shall apply.

C. Timely Request for Firm Transmission Made by Buyer, Accepted by the Receiving Transmission Provider and not Purchased by Buyer. If Buyer's Timely Request for Firm Transmission is accepted by the Receiving Transmission Provider but Buyer elects to purchase non-firm transmission rather than Firm Transmission to take delivery of the Product, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

D. No Timely Request for Firm Transmission Made by Buyer, or Buyer Fails to Timely Send Buyer's Rejection Notice. If Buyer fails to make a Timely Request for Firm Transmission or Buyer fails to timely deliver Buyer's Rejection Notice, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

4. Transmission.

A. Seller's Responsibilities. Seller shall be responsible for transmission required to deliver the Product to the Designated Interface or ADI, as the case may be. It is expressly agreed that Seller is not required to utilize Firm Transmission for its delivery obligations hereunder, and Seller shall bear the risk of utilizing non-firm transmission. If Seller's scheduled delivery to Buyer is interrupted as a result of Buyer's attempted transmission of the Product beyond the Receiving Transmission Provider's system border, then Seller will be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for damages pursuant to Article Four.

B. Buyer's Responsibilities. Buyer shall be responsible for transmission required to receive and transmit the Product at and from the Designated Interface or ADI, as the case may be, and except as specifically provided in Section 3A and 3B, shall be responsible for any costs associated with transmission therefrom. If Seller is attempting to complete the designation of an ADI as a result of Seller's rights and obligations hereunder, Buyer shall co-operate reasonably with Seller in order to effect such alternate designation.

5. Force Majeure. An "Into" Product shall be subject to the "Force Majeure" provisions in Section 1.23.

6. Multiple Parties in Delivery Chain Involving a Designated Interface. Seller and Buyer recognize that there may be multiple parties involved in the delivery and receipt of the Product at the Designated Interface or ADI to the extent that (1) Seller may be purchasing the Product from a succession of other sellers ("Other Sellers"), the first of which Other Sellers shall be causing the Product to be generated from a source ("Source Seller") and/or (2) Buyer may be selling the Product to a succession of other buyers ("Other Buyers"), the last of which Other Buyers shall be using the Product to serve its energy needs ("Sink Buyer"). Seller and Buyer

further recognize that in certain Transactions neither Seller nor Buyer may originate the decision as to either (a) the original identification of the Designated Interface or ADI (which designation may be made by the Source Seller) or (b) the Timely Request for Firm Transmission or the purchase of other Available Transmission (which request may be made by the Sink Buyer). Accordingly, Seller and Buyer agree as follows:

A. If Seller is not the Source Seller, then Seller shall notify Buyer of the Designated Interface promptly after Seller is notified thereof by the Other Seller with whom Seller has a contractual relationship, but in no event may such designation of the Designated Interface be later than the prescheduling deadline pertaining to the Transaction between Buyer and Seller pursuant to Section 1.

B. If Buyer is not the Sink Buyer, then Buyer shall notify the Other Buyer with whom Buyer has a contractual relationship of the Designated Interface promptly after Seller notifies Buyer thereof, with the intent being that the party bearing actual responsibility to secure transmission shall have up to 30 minutes after receipt of the Designated Interface to submit its Timely Request for Firm Transmission.

C. Seller and Buyer each agree that any other communications or actions required to be given or made in connection with this "Into Product" (including without limitation, information relating to an ADI) shall be made or taken promptly after receipt of the relevant information from the Other Sellers and Other Buyers, as the case may be.

D. Seller and Buyer each agree that in certain Transactions time is of the essence and it may be desirable to provide necessary information to Other Sellers and Other Buyers in order to complete the scheduling and delivery of the Product. Accordingly, Seller and Buyer agree that each has the right, but not the obligation, to provide information at its own risk to Other Sellers and Other Buyers, as the case may be, in order to effect the prescheduling, scheduling and delivery of the Product

"Native Load" means the demand imposed on an electric utility or an entity by the requirements of retail customers located within a franchised service territory that the electric utility or entity has statutory obligation to serve.

"Non-Firm" means, with respect to a Transaction, that delivery or receipt of the Product may be interrupted for any reason or for no reason, without liability on the part of either Party.

"Non-market-based Transmission Services" or "NMB" means both charges and credits associated with Network Integration Transmission Services ("NITS"), Transmission Enhancement, Expansion Cost Recovery, Non-Firm Point-to-Point Transmission Services, Regional Transmission Expansion Plan ("RTEP"), and Generation Deactivation, with the definitions ascribed to them in the PJM Agreements.

"System Firm" means that the Product will be supplied from the owned or controlled generation or pre-existing purchased power assets of the system specified in the Transaction (the "System") with non-firm transmission to and from the Delivery Point, unless a different Transmission Contingency is specified in a Transaction. Seller's failure to deliver shall be excused: (i) by an event or circumstance which prevents Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Seller; (ii) by Buyer's failure to perform; (iii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on, the System; (iv) to the extent the System or the control area or reliability council within which the System operates declares an emergency condition, as determined in the system's, or the control area's, or reliability council's reasonable judgment; or (v) by the interruption or curtailment of transmission to the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Seller's performance. Buyer's failure to receive shall be excused (i) by Force Majeure; (ii) by Seller's failure to perform, or (iii) by the interruption or curtailment of transmission from the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Buyer's performance. In any of such events, neither party shall be liable to the other for any damages, including any amounts determined pursuant to Article Four.

"Transmission Contingent" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Seller's proposed generating source to the Buyer's proposed ultimate sink, regardless of whether transmission, if any, that such Party is attempting to secure and/or has purchased for the Product is firm or non-firm. If the transmission (whether firm or non-firm) that Seller or Buyer is attempting to secure is from source to sink is unavailable, this contingency excuses performance for the entire Transaction. If the transmission (whether firm or non-firm) that Seller or Buyer has secured from source to sink is interrupted or curtailed for any reason, this contingency excuses performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Article 1.23 to the contrary.

"Unit Firm" means, with respect to a Transaction, that the Product subject to the Transaction is intended to be supplied from a generation asset or assets specified in the Transaction. Seller's failure to deliver under a "Unit Firm" Transaction shall be excused: (i) if the specified generation asset(s) are unavailable as a result of a Forced Outage (as defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines) or (ii) by an event or circumstance that affects the specified generation asset(s) so as to prevent Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, and which is not within the reasonable control of, or the result of the negligence of, the Seller or (iii) by Buyer's failure to perform. In any of such events, Seller shall not be liable to Buyer for any damages, including any amounts determined pursuant to Article Four.

EXHIBIT A

MASTER POWER PURCHASE AND SALE AGREEMENT
CONFIRMATION LETTER

This confirmation letter shall confirm the Transaction agreed to on ___________, ___ between __________________________ ("Party A") and _____________________ ("Party B") regarding the sale/purchase of the Product under the terms and conditions as follows:

Seller: ____

Buyer: ____

Product:

[] Into _________________, Seller's Daily Choice

[] Firm (LD)

[] Firm (No Force Majeure)

[] System Firm

(Specify System: ____)

[] Unit Firm

(Specify Unit(s): ____)

[] Other ____

[] Transmission Contingency (If not marked, no transmission contingency)

[]	FT-Contract Path Contingency	[]	Seller	[]	Buyer
[]	FT-Delivery Point Contingency	[]	Seller	[]	Buyer
[]	Transmission Contingent	[]	Seller	[]	Buyer
[]	Other transmission contingency				

(Specify: ____)

Contract Quantity: ____

Delivery Point: ____

Contract Price:

Energy Price: ____

Other Charges: ____

Delivery Period: ______________________________

Special Conditions: ______________________________

Scheduling: ______________________________

Option Buyer: ______________________________

Option Seller: ______________________________

Type of Option: ______________________________

Strike Price: ______________________________

Premium: ______________________________

Exercise Period: ______________________________

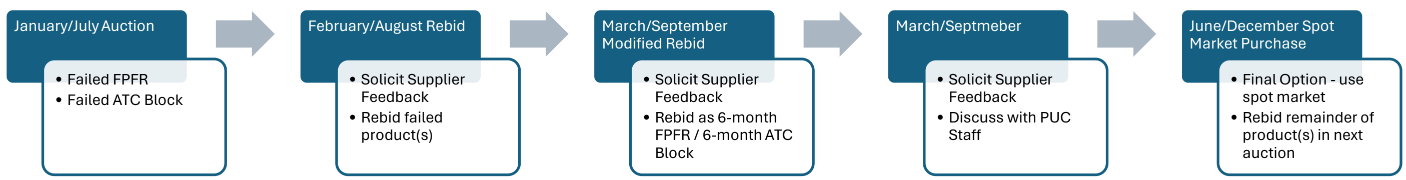
This confirmation letter is being provided pursuant to and in accordance with the Master Power Purchase and Sale Agreement dated ______________ (the “Master Agreement”) between Party A and Party B, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

[Party A]	UGI Utilities, Inc.
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Phone No: ______________________	Phone No: ______________________
Fax: ______________________	Fax: ______________________

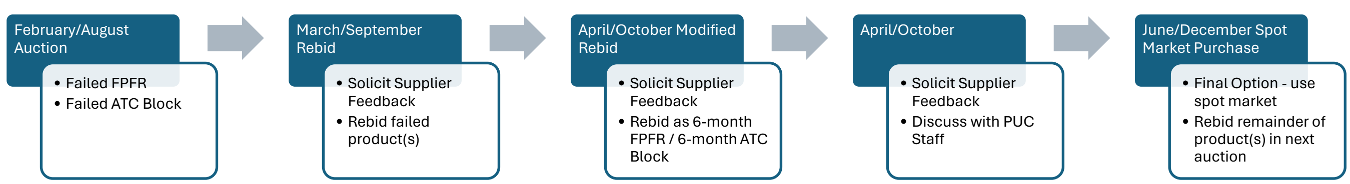
EXHIBIT JMR-8

CONTINGENCY OPTIONS

(1) Following a failed product auction in **January or July** (maximum gap between failed auction and supply start):



(2) Following a failed product auction in **February or August** (gap between failed auction and supply start is 2-3 months):



(3) Following a failed product auction in **March or September** (gap between failed auction and supply start is 2 or less months):

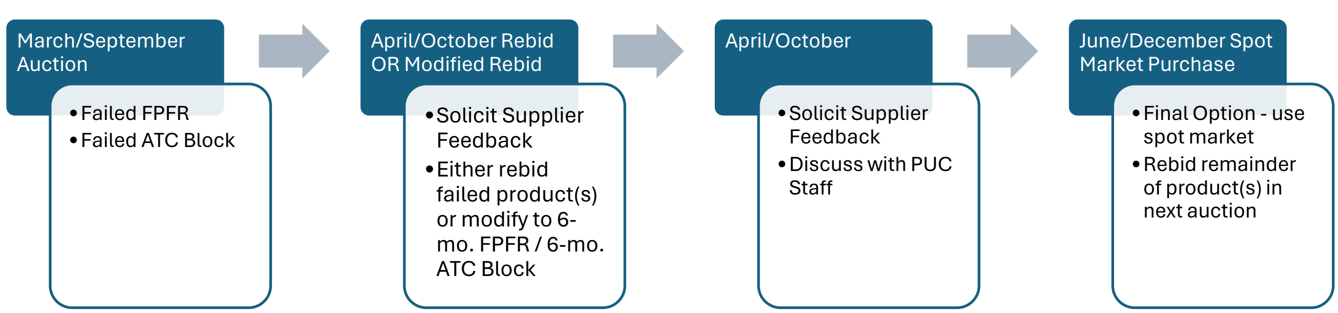


Exhibit JMR - 9

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

1. UGI Utilities, Inc – Electric Division ("UGI") is seeking quotes for supplying renewable energy certificates to meet its Alternative Energy Portfolio Standard ("AEPS") requirements. Bids must conform to the standards approved by the Pennsylvania Public Utility Commission ("PUC") in UGI's Default Service Supply filing (P-2024-______ and G-2024-_______)

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

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

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

5. Bidders may provide bids for one or more Tier types as desired. Each bid must be priced separately. For determining the winning bidder, each bid will be evaluated and awarded individually. Bids are for the full quantity of Alternative Energy Credits ("AEC") as defined in the table below. AEC submissions for quantities below the Quantity defined in the table below may be evaluated and/or selected at UGI's sole discretion – including but not limited to an event of under-bid for a given Tier Type.

6. Only credits certified by Pennsylvania as defined within the PJM Generation Attribute Tracking System ("PJM GATS") will be accepted. The Certification Number must be included for existing projects to verify that they meet the qualified criteria for compliance with the Pennsylvania AEPS Act.

7. The winning bidder must have a valid account through the PJM Environmental Information Systems, Inc.'s ("PJM-EIS") GATS for the facilitation of AEC transfers. GATS is the Commission designated credit registry.

8. Credits must be transferred to UGI's PJM GATS account within 10 business days following the execution of the contract. Payments will be made commensurate with the quantity of AECs transferred.

9. The Renewable Energy Certificate Purchase and Sale Agreement between UGI and the counterparty will control all transactions completed under this RFP. A draft of this agreement is posted on UGI's website at:

   [Insert Link]

10. All bids will be ranked based solely upon price, with the lowest priced bid being awarded the contract. In the event two or more bids are received that contain identical prices, tied bidders will be contacted to provide a best-and-final price, which may not be higher than the price originally bid in the solicitation. If this method does not break the tie, the winning bidder will be chosen at random by the UGI Auction Manager.

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

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

13. Solar AECs and Tier II AECs must adhere to updated regulations concerning geographic eligibility.

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

UGI is Seeking to Purchase the Following AECs

Tier Type	Quantity	Allowed Vintage by Compliance Year		% of AECs Allowed by Vintage
Tier I (Non-Solar)	[Enter]	June [Year] through May [Year]	Y	[%]
		June [Year] through May [Year]	Y	
		June [Year] through May [Year]	Y	[%]
Tier II	[Enter]	June [Year] through May [Year]	Y	[%]
		June [Year] through May [Year]	Y	
		June [Year] through May [Year]	Y	[%]
Solar	[Enter]	June [Year] through May [Year]	Y	[%]
		June [Year] through May [Year]	Y	
		June [Year] through May [Year]	Y	[%]

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

This bid is submitted in response to UGI's Request for Proposal dated [BID DATE - Month Day, Year].

Supplier Name ____

Primary Contact Phone ______________________________________

Primary Contact E-mail ______________________________________

Supply Type Pennsylvania Alternative Energy Credits

Vintage

- June [Year] through May [Year] – at least [%] or [Quantity]
- June [Year] through May [Year] – remaining quantity following adherence to above vintage requirement or [%]

Tier Type	Quantity	Bid Price* ($)
Tier I	[FILL]	$
Tier II	[FILL]	$
Solar	[FILL]	$

Place an "X**" if no bid is being placed for the AEC Tier Type. Please **DO NOT** place a zero (0).*

All bids must be submitted by e-mail to ugirfp@ugi.com by [Month Day Year]**, within the bid window of [HOUR START] to [HOUR END].**

Bids must remain open until the close of the business (5:00 p.m. E.T) on [PUC APPROVAL DATE - Month Day, Year]. Bidders must execute the Renewable Energy Certificate Purchase and Sales Agreement without modification upon winning bids within two business days following PUC Approval.

[Date]

Dear Sir or Madam,

RE: Request for Proposal to Purchase Alternative Energy Credits

UGI Utilities – Electric Division ("UGI") is seeking to purchase renewable energy certificates to fulfill a portion of its Alternative Energy Portfolio Standard ("AEPS") requirements. The Request for Proposals ("RFP") and bidding details are attached.

UGI is using a competitive bidding process to obtain Alternative Energy Credits ("AECs") to fulfill its obligations pursuant to Pennsylvania's Alternative Energy Standards Act. This RFP is issued to purchase AECs necessary to meet the AEPS obligation established under UGI's approved petition for a Default Service Supply Plan in Docket No. P-2024-________ and G-2024-________, to be effective [Date]. This plan established the mechanism by which UGI will procure AECs through a competitive solicitation process. Therefore, UGI is issuing this RFP to secure certain quantities of AECs as specified below. All acquisitions made through RFP's will be monitored by a third party, [Auction Manager], to ensure a fair and unbiased process. Shown below is the maximum quantity of AECs UGI is seeking to purchase. UGI reserves the right to purchase less than the maximum amount.

Tier Type	**Maximum Quantity to Purchase**	**Allowed Vintage by Compliance Year**		**Maximum Quantity to Purchase**
Tier I (Non-Solar)	[Enter]	June [Year] through May [Year]	Y/N	[%]
		June [Year] through May [Year]	Y/N	
		June [Year] through May [Year]	Y/N	[%]
Tier II	[Enter]	June [Year] through May [Year]	Y/N	[%]
		June [Year] through May [Year]	Y/N	
		June [Year] through May [Year]	Y/N	[%]
Solar	[Enter]	June [Year] through May [Year]	Y/N	[%]
		June [Year] through May [Year]	Y/N	
		June [Year] through May [Year]	Y/N	[%]

The schedule below provides key dates and times associated with this RFP.

<u>RFP Schedule</u>

[Date]	Notice of RFP sent to potential suppliers.
[Date]	Bidder Information Session
[Date] (1:00 p.m. E.T.)	RFP Conference Call with all interested parties Call-in Number – TBD Code – TBD
[Date] (12:00 p.m. E.T.)	Last day to submit questions.
[Date] (12:00 p.m. E.T.)	RFP responses due to UGI/[Auction Manager].
[Date] (1:00 p.m. E.T.)	Winning bidders selected by UGI/[Auction Manager], and verbally notified by UGI/[Auction Manager] of bid status
[Date] (2:00 p.m. E.T.)	Results of solicitation sent to Pennsylvania PUC.
[Date+1]	Pennsylvania PUC approves results of RFP.
[Date+1]Close of Business	UGI/[Auction Manager] verbally notifies winning bidders.

Responses to this RFP must be submitted through e-mail to ugirfp@ugi.com by **<u>[Date] at 12:00 p.m. E.T.</u>** Through this e-mail address, both UGI and [Auction Manager] will receive your bid and will independently evaluate the responses and determine the winning bidders. Bids that have a time stamp after 12:00 p.m. will not be considered.

Questions pertaining to this RFP must be received before 12:00 p.m. on [Date]. Questions and Responses will be posted on UGI's website which can be found at:

[Insert Link]

Once the winning bidders are determined, the results must be forwarded to the PUC, which will either accept or reject the winning bids. Therefore, all bids must remain open until the end of the first business day following submission. While UGI cannot dictate a timeline to the PUC, it is hoped the PUC will approve the results of the RFP within one (1) business day of the bid deadline. Immediately following the PUC's decision, UGI/[Auction Manager] will then contact the winning bidders by telephone to confirm the transaction(s).

By providing a bid, interested parties agree to execute the provided Renewable Energy Certificate Purchase and Sale Agreement contract without any modifications. UGI will require that this contract be executed upon awarding the bids.

If the winning bidder fails to deliver the credits awarded to them, UGI will purchase replacement credits and bill the defaulting party for any additional costs incurred.

The criterion for selecting winning bids will be based on price and the generation period. In the event of identical winning bids, credits will be awarded to the winning bidders on a pro rata basis.

Thank you,

UGI

Exhibit JMR-10

Transaction Confirmation

Date: [Insert]

Re: Alternative Energy Credits

This Transaction Confirmation, together with the attached General Terms and Conditions, constitute the Purchase and Sale Contract ("Contract") between [Insert Seller Name], as Seller, and UGI Utilities, Inc. – Electric Division, as Buyer (together, the "Parties") based on the terms set forth herein.

Seller: [Insert Seller Name]

Buyer: UGI Utilities, Inc.

Product: Alternative energy credits ("AECs") as defined as of the date first set forth above in Title 73, Chapter 18F, Alternative Energy Portfolio Standards Act, Sections 1648.1 though 1648.8 of the Pennsylvania Statutes (the "AEPS Act"). The AEC's will be administered and transferred, under the terms and conditions hereof, by the Environmental Information Services of PJM Interconnection, LLC ("PJM-EIS") Generation Attribute Tracking System ("GATS") in connection with its obligations hereunder at such time as Seller transfers to Buyer, through GATS, the Quantity of AECs recognized as meeting Pennsylvania AEPS Act requirements.

Facilities: [Insert As Appropriate]

Transaction Type: [Insert As Appropriate]

Tier Type: [Insert]

Price: [Insert]

Vintage Requirements: [QTY] June [Year] through May [Year]; [QTY] June [Year] through May [Year]

Delivery and Payment: The Product will be delivered and paid for under the following terms:

(i) AECs to be delivered by _________________.
(ii) Within __ Business Days of Buyer's receipt of the Product, Buyer will pay to Seller an amount equal to the product of (i) the Quantity, and (ii) the Price.

Delivery will be effectuated through PJM-EIS using GATS. Title to the Product and risk of loss will transfer at such time as PJM-EIS recognizes the transfer of the Product to Buyer through GATS.

Payment: Payment by Buyer to Seller shall be made to the following account:

Wire Instructions:
____
____

Term: This Contract will terminate after the Quantity of the Product has been delivered and paid for under the terms hereof. Sections 1, 4, 7 and 8 of the General Terms and Conditions will survive termination to the extent necessary for the Parties to enforce their rights hereunder.

Special Conditions:

1. If a fee is assessed by the Pennsylvania Public Utility Commission (or any other governmental entity) in connection with the transfer of certification of the AECS, as

between the Parties Buyer will be responsible for such amounts. Buyer will indemnify, defend and hold harmless Seller from and against any such fees for which Buyer is responsible.

2. The General Terms and Conditions attached hereto are included herein for all purposes and are an integral part of this Contract. Provided, that, to the extent there is any conflict between a provision in the General Terms and Conditions and this Transaction Confirmation, the terms of the Transaction Confirmation shall control. This Contract sets forth the entire agreement between the Parties with respect to the AEC purchase identified in this document superseding any and all contemporaneous or prior conversations, memoranda, agreements (oral or written) or other communication with respect to its subject matter between the Parties or any of their respective agents. There are no third party beneficiaries to this Contract. This Contract may not be terminated (other than as provided in this Contract) or changed except by a writing signed by both Parties. No right, obligation or provision of this Contract shall be deemed waived unless such waiver is evidenced by a writing signed by the Party charged with the waiver and any such waiver shall be strictly limited to the express terms of such writing. No representations or warranties have been given other than those expressly stated in this Contract to induce either Party to enter into this Contract.

IN WITNESS WHEREOF, and intending to be legally bound, the Parties have executed this Contract by the undersigned duly authorized representatives as of the date of this Contract.

________________		UGI Utilities, Inc. – Electric Division	
Signature:	________________	Signature:	________________
Name:	________________	Name:	________________
Title:	________________	Title:	________________
Date:	________________	Date:	________________

GENERAL TERMS AND CONDITIONS

1. Events of Default and Remedies:

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

(a) the failure to make, when due, any payment required pursuant to this Contract if such failure is not remedied within three (3) business days after written notice;

(b) the failure by Seller to deliver to Buyer, when required pursuant to this Contract, the AECs if such failure is not remedied within three (3) business days after written notice;

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

(d) a material breach of a covenant or obligation (other than as separately provided for in this Section 1.1) set forth in this Contract not cured within five (5) days following written noticed thereof;

(e) such Party:

(i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it and not discharged within thirty (30) days,

(ii) makes an assignment or any general arrangement for the benefit of creditors,

(iii) otherwise becomes bankrupt or insolvent (however evidenced),

(iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or

(v) is generally unable to pay its debts as they fall due.

1.2 If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party shall have the right to (i) suspend performance, (ii) withhold any payments due to the Defaulting Party under this Contract, and (iii) terminate this Contract on two (2) business days prior notice to accelerate all amounts owing between the Parties and to liquidate and recover its damages or enforce specific performance resulting from such Event of Default.

2. No Waiver. No waiver at any time by any Party hereto of its rights with respect to the other Party or with respect to any matter arising in connection with the Contract shall be considered a waiver with respect to any subsequent default or matter.

3. Assignment. Neither Party shall assign this Contract without the prior written consent of the other Party, which consent may not be unreasonably withheld; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer or assign this Contract to an affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (ii) transfer or assign this Contract to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request, and further provided that with respect to (ii) above, the assigning Party ("Assignor") shall be relieved of liability hereunder so long as the benefits of any Guaranty provided by the Assignor extends to the obligations of the Assignee pursuant to documentation or amendment reasonably satisfactory to the other Party.

4. Taxes and Indemnity. Seller will be responsible for any taxes imposed by any government authority on the creation, ownership, or transfer of the Product under this contract up to and including the time and place at which title transfers. Buyer will be responsible for any taxes imposed by any government authority on the receipt of ownership of the Product after the time and place at which title transfers. For avoidance of doubt, the foregoing two sentences will not apply, however, to the assessment of any fee as contemplated by Section 2 of the Special Conditions in the Transaction Confirmation. Each Party will indemnify, defend and hold harmless the other Party from and against any claims or demands made by others arising from or out of any event, circumstance, act or incident first occurring or existing during the period when title to the Product is vested in such Party as provided herein, except to the extent arising from such Party's own gross negligence or willful misconduct. Each Party will indemnify, defend and hold harmless the other Party against any taxes for which such Party is responsible as provided herein.

5. Representations.

5.1 From the date of entering into this Contract and throughout the Term of this Contract, the Parties each warrant and covenant as follows:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(b) it has all regulatory authorizations necessary for it to legally perform its obligations under this Contract;

(c) it has the requisite authority to enter into and perform its respective obligations under the contract;

(d) the obligations hereunder are binding on it;

(e) it is not the subject of any bankruptcy proceeding or involved in litigation that would materially affect its ability to perform hereunder, except as provided for in any SEC Filing by it or any of its affiliates;

(f) the contract has been negotiated in the ordinary course of business, in good faith, for fair consideration on an arms length basis between Parties of equal sophistication and represents a bargained for exchange; and

(g) it has entered into this Contract in connection with the conduct of its business and it has the capacity and ability to perform its obligations hereunder.

6 Notices. All notices to _______ shall be given to:

____
____
____

With additional Notices of an Event of Default or Potential Event of Default to:

____
____
____

All notices to UGI Utilities, Inc. – Electric Division under the contract shall be given to:

[Insert Title]

Email: [Insert email] Phone: [Insert Phone]

With additional Notices of an Event of Default or Potential Event of Default to:

[Insert Title]

Email: [Insert email] Phone: [Insert Phone]

Except as otherwise expressly provided herein, all notices to the other Party under the Contract shall be in writing and shall be deemed effective upon receipt if received prior to 5:00 p.m., local time, on a business day, or on the next succeeding business day if otherwise.

7. <u>Choice of Law.</u> This contract will be governed by the laws of the state of Pennsylvania.

8. <u>Waiver of Jury Trial.</u> Each Party waives its respective right to any jury trial with respect to any litigation arising under, or in connection with this Contract.

APPENDIX D

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY
OF
TRACY A. HAZENSTAB

UGI ELECTRIC STATEMENT NO. 3

Dated: May 31, 2024

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab, and my business address is UGI Utilities, Inc., 1 UGI Drive, Denver, Pennsylvania 17517.

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

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

Q. What are your responsibilities as Principal Analyst, Rates?

A. I am primarily responsible for various tariff filings and related computations for UGI Electric and UGI Gas rate and regulatory filings before federal and state regulatory commissions.

Q. Please describe your educational and professional experience.

A. Please see my resume, UGI Electric Exhibit TAH-1, which is attached to my testimony.

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

A. Yes. UGI Electric Exhibit TAH-1 contains a list of the proceedings in which I previously testified.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Electric in support of its proposed Default Service Plan V ("DSP V" or the "Plan"). Specifically, I will address the rate design and Section 1307(e) cost recovery mechanisms that are currently used to recover the costs of UGI Electric's existing DSP IV and that will continue to be used during DSP V for the term of June 1, 2025 through May 31, 2029. My testimony will also address certain tariff updates clarifying the applicability of UGI Electric's Generation Supply Rate ("GSR") and Price-to-Compare ("PTC"), in particular as related to customers receiving default service under UGI Electric's GSR-2 rate (service with supply peak load impact of 100kW and above) and implementing clear guidelines related to its applicability for net metering customer-generators. I will also discuss additional tariff modifications and retail enhancement programs in DSP V.

Q. Are you sponsoring any exhibits?

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

II. OVERVIEW OF DEFAULT SERVICE RATES

Q. Please describe the current structure of UGI Electric's default service rates.

A. In DSP IV, UGI Electric applies a GSR to customer bills for those customers receiving default service from the Company. The GSR has two rate groups, those being GSR-1 and GSR-2. Customers having a system impact equal to or greater than 100kW are assigned to GSR-2 in accordance with DSP IV provisions.

Q. Is the Company proposing any changes to the structure of its default service rates?

A. Yes, the Company is proposing tariff modifications that will improve the clarity of the tariff language. These changes will assign customers to a GSR rate group (GSR-1 or GSR-2) based on their default supply peak load impact. Those customers with larger ability for peak load impact greater than or equal to 100kW shall be assigned to the GSR-2 rate group. The Company is also expanding its tariff language to better identify the treatment of customer-generators and align its DSP with the operational impact of these entities as discussed in the testimony of UGI Electric witness James M. Rouland, UGI Electric Statement No. 2.

Q. What customers are included in GSR-1?

A. GSR-1 shall apply to all residential customers as well as non-residential customers with a supply peak load impact less than 100 kW.

Q. What customers are included in GSR-2?

A. GSR-2 shall apply to all non-residential customers with a supply peak load impact greater than or equal to 100 kW.

Q. Is the Company proposing any other tariff changes regarding the classification of GSR-1 and GSR-2 customers?

A. Yes. Consistent with the Company's Settlement commitment in DSP IV, the Company evaluated the classification of customers to the applicable GSR rate at the start of the Plan, using the Customer's highest billing demand in the twelve-month period ending September 30, 2020. Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-2 customers that migrated from rate GSR-1 was refunded/recovered from those customers directly over 12 billing periods beginning September 1, 2021. This over/under collection totaled $2,585 and was allocated to GSR-1 and GSR-2 customers based on the percentage of the actual sales during the period of the over/under collection attributed to those customers as of June 1, 2021. Additionally, customers who underwent reverse migration, switching from GSR-2 to GSR-1 during the DSP IV term, were exempted from any over/under collections as reflected in the Company's E-factor (existing as of May 31, 2021) for a period of 12 months after returning to GSR-1.

In DSP V, the Company is proposing to conduct this review annually. Also, the basis for determination shall be the Customer's peak load impact on the Company's default service supply activities. Specifically, where a Customer's supply peak load impact is greater than or equal to 100kW, GSR-2 will apply. Supply peak load impact will be determined on a Customer's net demand contribution impact to the Company's default service procurement activity, as determined upon the net power flow from or into the Company's distribution system. This approach recognizes that the magnitude of impact on default service supply activities is similar for all large peak load Customers, even in situations where net power from a net metering customer-generator is flowing into the Company's distribution system. Additionally, the Company is proposing to eliminate the migration charges and the reverse migration charges because the determination and movement of customers between applicable GSR-1 or GSR-2 rates will occur on a timely basis. Historically, the migration rider charges transferred to GSR-2 customers have been minimal, even where the Company did not use an annual evaluation process.

Q. What costs are included for GSR-1 rates?

A. The Company's GSR-1 rates include the supply procurement portfolio described in the testimony of Mr. Rouland. The GSR-1 rates include the costs from all deliveries made pursuant to supply contracts and spot market purchases required to serve the Company's GSR-1 customers, PJM-related costs, costs associated with the purchase of renewable energy credits procured in order to meet UGI Electric's requirements under the Alternative Energy Portfolio Standards Act ("AEPS"), net metering payments to customer-generators made at the Price-to-

Compare rate for GSR-1 customers (PTC-1), as well as administrative costs associated with the provision of default service to customers.

Q. What costs are included for GSR-2 rates?

A. The Company's GSR-2 rates will include the supply from the procurement method described in the testimony of Mr. Rouland. GSR-2 customers are served on an hourly basis through purchases made in the spot market at the generation supply prices established by PJM's real-time hourly market. For these procurements, the Company will pass through the costs associated with any necessary PJM-related costs, such as capacity, transmission to UGI Electric's system, ancillary services, congestion management services, AEPS credits, net metering payments made at the PTC rate for GSR-2 customers (PTC-2) customer-generators, administrative costs associated with the provision of default service to customers, and such other services or products as necessary to provide default service supply. PJM will bill UGI Electric for the hourly usage and related costs on a monthly basis.

III. <u>PJM COSTS</u>

Q. What PJM costs does UGI Electric incur in its provision of default service?

A. UGI incurs fees from PJM for capacity, load response, ancillary charges, administrative fees, and non-market-based transmission costs.

Q. How are non-market-based transmission costs for load following service currently accounted for in DSP rates?

A. Currently, the non-market-based transmission costs are included in the GSR-1 rate in two different ways. For supply that is received through the Company's load following contracts, these costs are currently included as part of the total all-in pricing offered by the supplier. For the portion of the Company's portfolio that is made up of block and spot purchases, as well as the entirety of the GSR-2 supply activities, the costs are billed to UGI Electric by PJM monthly and are allocated for inclusion in the calculation of the GSR-1 and GSR-2 rates.

Q. Is the Company proposing any changes to how it will record non-market-based transmission costs?

A. Yes. As described in Mr. Rouland's testimony, the Company is proposing to remove the non-market-based transmission costs from its load following contracts. Therefore, the associated PJM costs will be billed directly to UGI Electric by PJM. These PJM costs related to default supply to GSR-1 customers will be appropriately allocated to GSR-1 for recovery. This proposal should have no impact on the PJM costs included in rates for GSR-2 customers.

IV. AEPS COSTS

Q. How will the costs be established for AEPS credits in DSP V?

A. During DSP V, UGI Electric will procure AEPs credits consistent with the procurement proposal included in the testimony of Mr. Rouland. For GSR-1, that entails a combination of AEPs credits purchased directly by UGI Electric, as well as credits purchased by the load following suppliers. For GSR-2, UGI Electric will purchase all credits required for compliance. The cost of the credits purchased will be allocated to GSR-1 and GSR-2 customers based on metered sales.

Q. Are there any costs that the Company might incur if it does not meet its AEPS compliance targets?

A. Yes. After the true-up period expires, in the unlikely scenario that the Company is still unable to meet its AEPS credit targets in Section 52 Pa. Code § 75.61, the Company would be required to pay the applicable alternative compliance payment(s) specified in 52 Pa. Code § 75.65(b). The Company proposes to recover all AEPS credit procurement costs, including compliance costs, through its default service rates.

V. ADMINISTRATIVE COSTS

Q. Is UGI Electric proposing to recover administrative costs incurred in procuring Default Service supply?

A. Yes, UGI Electric is proposing to recover Administrative and General ("A&G") expenses associated with the provision of default service for the GSR-1 and GSR-2 customer groupings. This treatment of A&G expenses is consistent with the Company's historic practice.

Q. What costs are included in UGI Electric's A&G expense category in the DSP?

A. The A&G costs included in the GSR rates cover the following activities: auction management; load forecasting; development of the DSP V procurement plan, internal company costs, legal costs, metering, and billing. The categories of costs included in the DSP V are similar in nature to those included during the Company's DSP IV plan, with some further expansion as discussed in Mr. Tyahla's testimony. All applicable administrative costs are identified in UGI Electric Exhibit TAH-2 with forecasted values. Actual costs will be allocated to GSR-1 and GSR-2 as outlined in the exhibit. As identified in UGI Electric Exhibit TAH-2, certain of these costs will be included in GSR-1 and GSR-2 on a reconcilable basis and certain will be fixed or non-reconcilable costs.

Q. What is the anticipated total impact of the administrative costs UGI Electric proposes to include in its DSP V, on an annual basis?

A. On an annual basis, the administrative costs will average $557,891, inclusive of Gross Receipts Tax. Approximately $425,528 of these costs will be allocated to GSR-1, with the remaining $132,363 allocated to GSR-2. Estimated administrative costs allocated to GSR-1 and GSR-2 in DSP IV totaled $203,745 and $70,039, respectively. The increase is attributed to increased legal expense to more closely align with anticipated legal expense to be incurred during DSP V, the inclusion of a procurement plan consultant, the addition of an auction manager in DSP V, and increased labor costs.

Q. For A&G expenses that are amortized, is the Company proposing any changes to its current amortization practices?

A. Yes. In DSP IV, any invoices that were amortized are being amortized through the months that are remaining in the DSP IV plan, regardless of the size of the invoice. In DSP V, the Company is proposing to only amortize those invoices that are above a threshold of $5,000. The $5,000 threshold is consistent with business practices used in other areas of the Company. Placing a limit on the size of invoices that are amortized will streamline business practices and have no impact to customers' rates.

VI. RECOVERY OF COSTS

Q. How does the Company plan to recover the default service costs through its tariff?

A. The rate design plan for DSP V recovers these costs on a full and current basis through a Section 1307 reconcilable adjustment clause (including costs for complying with the AEPS Act). The Company's DSP V will include a rate design that recovers costs associated with procurements for the GSR-1 and GSR-2 groupings, including AEPS credits.

Q. Is the Company proposing any modifications to its current rate calculation methodology?

A. Yes. As discussed in the testimony of Mr. Tyahla, and consistent with the Settlement of DSP IV,[1] the Company hired NorthBridge Group to conduct a procurement study. The study recommended the Company utilize relative cost factors to calculate separate default service rates for residential and non-residential customers, which would apply specifically to the Energy Cost (EC) component. The Company proposed to implement these allocation factors in DSP V as part of the Settlement of DSP IV. As the procurement study recommended that the Company could utilize the same allocation factors for a multi-year period, the Company is proposing to utilize the factors calculated in the study for the duration of DSP V. In order to calculate the residential default service rate, the EC component will be multiplied by 1.02. A factor of 0.93 would be applied to the EC component to calculate the non-residential rate. The application of these factors would calculate separate EC components for the residential and non-residential customers. Should GSR-1 or GSR-2 supply load change by more than 50% during the course of DSP V, the Company will update the procurement study and utilize the new resulting relative cost factors.

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[1] *See Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021 through May 31, 2025*, Docket No. P-2020-3019907 (Order entered Jan. 14, 2021).

Q. Please describe the proposed rate calculation for GSR-1 customers, as modified by the allocation factor.

A. The GSR-1 tariff rate appears in UGI Electric Appendix A (a copy of the Company's updated pro forma tariff pages for Rider B – Generation Supply Service) and will be calculated according to the following formula:

GSR-1 = (((EC*F)/SEC) + (ECA/SECA) + (Int/Sint)) * (1/(1-T))

Where:

- <u>Energy Costs (EC)</u> – Projected direct and indirect purchase power costs (for load following procurements) in the upcoming computation period, including all PJM bill line items, administrative costs, AEPS credits, net metering costs related to required excess power purchases pursuant to PTC-1, etc. The EC will be multiplied by the appropriate <u>Relative Cost Factors (F)</u> and divided by <u>Sales for the Projected Period (SEC)</u>. The SEC includes projected sales for all default service customers in GSR-1 for the upcoming computation period.

- <u>Energy Cost Adjustment (ECA)</u> – The ECA (i.e., E-Factor) is the net over or under collection related to the EC, which is collected/refunded for the computation period based on EC revenues received and actual EC costs incurred for the six-month period ending 2 months before the GSR effective date. The ECA is divided by the <u>Sales Used to Calculate the ECA (SECA)</u>. The SECA includes projected sales for all default service customers in GSR-1 for the adjustment period. If the ECA would result in less than (or equal to) five percent (5%) change in the average total Residential bill, the Company will calculate the ECA over six-months of sales. If the ECA would result in more than a 5% change in the system average total Residential bill for default service, UGI will refund/recover the balance over twelve months of sales.

- <u>Interest (Int)</u> – Interest associated with over and under collections. The interest is computed at the prime rate for commercial banking, not to exceed the legal rate of interest as reported in the Wall Street Journal. The Int is divided by the <u>Sales Interest (Sint)</u>. The Sint includes the projected sales for default service customers in GSR-1 for the computation period.

- Taxes (T) –Taxes (i.e., Pennsylvania Gross Receipts Tax) are applied to the sum of the above-components.

Q. Please describe the proposed rate calculation for GSR-2 customers.

The rate design for costs associated with procurements for the GSR-2 grouping (appears in UGI Electric Appendix A, the updated pro forma tariff pages for Rider B – Generation Supply Service) will be calculated for each default service customer in the group and will be based on actual costs incurred to serve the customer. The GSR-2 rate will be calculated according to the following formula:

$$GSR\text{-}2 = (HEC + HPC + HTC) * (1/(1\text{-}T))$$

Where:

- Energy Costs (HEC) incurred by the Company to procure electric supply are multiplied by the customer's LMP for each hour of the billing month.
- Other Power Costs (HPC) incurred in the procurement of electric supply, which are allocated according to metered sales. These costs include AEPS credits, PJM bill line items (excluding costs for capacity services, transmission services, network transmission service credits and firm point-to-point transmission expenses/credits), net metering costs related to required excess power purchases pursuant to PTC-2, legal costs, taxes, and any other applicable costs.
- Costs for Capacity and Transmission (HTC) included on the PJM bill are allocated to GSR-2 customers in two different ways. Capacity costs include locational reliability, capacity transfer rights, RPM auction and capacity resource deficiency costs. These costs are allocated based on each customer's peak load contribution ("PLC"). Transmission costs include network integration service charges, transmission enhancement service charges/credits and non-firm point-to-point transmission service charges/credits. These costs are allocated based on each customer's network service peak load value ("NSPL").
- Taxes (T) – Taxes (i.e., Pennsylvania Gross Receipts Tax) are applied to the sum of the above-components.

Q. How will supply costs be billed for GSR-2 customers?

A. An individual GSR-2 bill shall be calculated for each default service customer in this group based upon actual costs plus allocated administrative costs as described in UGI Electric Exhibit TAH-2. Pro forma tariff pages setting forth the proposed GSR-2 are provided in Appendix A to the Company's Petition.

Q. Is the Company proposing any modification to the frequency of rate changes for the GSR-1 customers?

A. Yes. The Company currently calculates rate changes for GSR-1 customers on a quarterly basis. The Company is proposing to change to semi-annual rate changes. The rates will become effective June 1 and December 1 to align with the June 1 plan start. Tariff filings will be made to the Commission on 30-days' notice. As part of this proposal, and to transition customers to the frequency update, the Company proposes to recover the over/under collection for January 1, 2025 – March 31, 2025, over the six-month period of June 1, 2025 – November 30, 2025. Thereafter, the June 1 rate will capture the actual over/under collection for the period October 1 – March 31 and the December 1 rate will calculate the actual over/under collection for the period April 1 – September 30. Pro forma tariff pages setting forth the proposed GSR-1 are provided in Appendix A to the Company's Petition.

Q. What is the proposed reconciliation period for the GSR-1 rate?

A. On or before June 30th of each year, the Company will file an annual reconciliation statement for the GSR-1 rate for the preceding 12-months ending May 31. The reconciliation statement will contain aggregated costs and revenues for residential and non-residential customers.

VII. PRICE TO COMPARE

Q. How does UGI Electric currently establish the PTC?

A. Currently, pursuant to its tariff as contained within Rider B – Generation Supply Service Surcharge, the GSR-1 customer PTC is calculated at the GSR-1 rate plus the State Tax Adjustment Surcharge. For the purposes of clarity, UGI Electric is adding the designation "PTC-1" to its tariff to align with the GSR-1 designation of the rate.

Q. How does UGI Electric propose to modify the PTC-1 as part of this proceeding?

A. As part of this proceeding, UGI Electric proposes to calculate a separate price to compare for the residential and non-residential customers served under GSR-1. This change is necessary due to the addition of relative cost factors in the GSR-1 rate calculation that will result in separate residential and non-residential GSR-1 rates.

Q. What PTC is currently applicable for GSR-2 customers?

A. For GSR-2 customers, Rider B currently notes that "PTC is not applicable to GSR-2."[2] This is because the PTC for GSR-2 is not an absolute price value, as GSR-2 customers are priced hourly in accordance with the PJM Locational Marginal Price ("PJM LMP"), plus associated allocated costs.

Q. How does UGI Electric propose to clarify the application of a PTC for GSR-2 customers?

A. As part of this proceeding, UGI Electric proposes to clearly identify that an appropriate price to compare for the GSR-2 customers is the applicable hourly PJM LMP (plus associated allocated costs) for the service time period. Thus, UGI Electric is proposing to update the applicable tariff language to clarify that the Price to Compare for GSR-2 customers, the "PTC-2", shall be the GSR-2 rate plus the State Tax Adjustment Surcharge in Rider A.

Q. Do any other Pennsylvania EDCs similarly distinguish the PTC for GSR customers with higher system demand?

A. Yes. In particular, PPL Electric Utilities Corporation's price to compare reflects that customers receiving Real Time Pricing based default service rates also have a PTC based upon Real Time Pricing.[3]

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[2] *See* UGI Electric Tariff Pa. P.U.C. No. 6, Supplement No. 52 at Second Revised Page No. 41.

[3] *See* https://www.pplelectric.com/utility/about-us/for-generation-suppliers/general-supplier-reference-information/price-to-compare-and-shopping

Q. How will this tariff update assist customers?

A. The clarifying language proposed by UGI Electric will readily assist GSR-2 customers in transparently understanding the basis for and applicability of the GSR-2 PTC-2.

Q. Please explain how the Company will provide notification of its PTC-1 and PTC-2.

A. Continuing current practice, the PTC-1 will be posted on PAPower Switch and the Company's website and will be provided to the Office of Consumer Advocate 30 days prior to its effective date. Separate price to compare rates will be posted for residential and non-residential customers under PTC-1 and will be included as a message on customer bills. This 30-day notification aligns with the submission of the tariff filings to the Commission and permits sufficient time, should it be needed, for the Company to execute on supply procurement contingency plans. Because this notification timeframe is outside of the window established in 52 Pa. Code § 54.188(e)(2), the Company is requesting a waiver of the Commission's noticing requirements. A formula for the calculation of PTC-2 will be posted on the Company's website and will also be included as a message on customer bills.

Q. Is the Company proposing to update the Net Metering section of the tariff?

A. Consistent with the designation and clarification related to PTC-1 and PTC-2 language above, commensurate updates to the net metering language found in tariff Section 17 have been made. Also, language additions have been made to clarify the end of the net metering annual period is associated with the end of the billing period falling in May. This recognizes that some net metering customers will not have billing periods that exactly match calendar months. The Company has also clarified the timing of payments related to the purchase of excess generation annually. Finally, the Company has removed outdated language related to the need for independent load at net metering installations.

VIII. RETAIL ENHANCEMENT PROGRAMS FOR DSP V

Q. What retail enhancement programs will the Company continue during DSP V?

A. Consistent with DSP IV, DSP V will continue two retail enhancement programs: (1) the New/Moving Customer Referral Program; and (2) the Standard Offer Customer Referral Program.

Q. What is the New/Moving Customer Referral Program?

A. The Company's New/Moving Customer Referral Program provides customers new to, or moving within, the service territory information about retail choice during service calls to UGI Electric. During these calls, UGI Electric will refer its customers to the Commission's PA Power Switch website. The Company also will explain how the Company's PTC can be used in considering EGS price offers and how the PTC changes over time. Further, the Company will explain the difference between fixed and variable generation supply contract options.

Q. Does the Company currently have any EGSs participating in the Standard Offer Program?

A. While the Company stands ready to support a Standard Offer Program, there are no retail EGSs that are currently participating in UGI Electric's Standard Offer program.

Q. Does this conclude your testimony?

A. Yes.

UGI Electric Exhibit TAH-1

Tracy A. Hazenstab
Principal Analyst - Rates

Work Experience:

2008 - Current	Rates Analyst – II/Sr/Principal (Progressive Positions) UGI Utilities, Inc., Denver, PA
2004 - 2008	Business Analyst PPL Gas, Lewistown, PA
2001 - 2004	Contact Center Analyst PPL Gas, Lock Haven, PA

Previous Testimony – Pennsylvania Public Utility Commission:

2014 1307(f) Proceeding:	Docket No. R-2014-2543523
2015 1307(f) Proceedings:	Docket Nos. R-2015-2480937, R-2015-2480934
2016 1307(f) Proceedings:	Docket Nos. R-2016-2543311, R-2016-2543314
2018 1307(f) Proceedings:	Docket Nos. R-2018-3001631, R-2018-3001632
2019 1307(f) Proceeding:	Docket No. R-2019-3009647
2019 UGI Electric EEC Phase III Petition:	Docket No. R-2019-3004144
2020 1307(f) Proceeding:	Docket No. R-2020-3019680
2021 UGI Gas Base Rate Proceeding:	Docket No. R-2021-3030218
2022 UGI Electric Base Rate Proceeding:	Docket No. R-2022-3037368
2023 1307(f) Proceeding:	Docket No. R-2023-3040290
2024 UGI Gas EEC Phase II Petition:	Docket No. R-2024-3048418

Previous Testimony – Maryland Public Service Commission:

Purchased Gas Adjustment/Annual Cost Adjustment Hearing:

2008 Hearing:	Case Number 9511(c)
2009 Hearing:	Case Number 9511(d)
2010 Hearing:	Case Number 9511(e)
2012 Hearing:	Case Number 9511(g)
2014 Hearing:	Case Number 9511(i)
2015 Hearing:	Case Number 9511(j)
2016 Hearing:	Case Number 9511(k)
2017 Hearing:	Case Number 9511(l)
2018 Hearing:	Case Number 9516(a)
2019 Hearing:	Case Number 9516(b)
2020 Hearing:	Case Number 9516(c)

Assisted in Preparing – Pennsylvania Public Utility Commission:

2009 UGI Gas Rate Case (former Central Rate District):	Docket No. R-2008-2079675
2009 UGI Gas Rate Case (former North Rate District):	Docket No. R-2008-2079660
2011 UGI Gas Rate Case (former Central Rate District):	Docket No. R-2010-2214415
2016 UGI Gas Rate Case (former South Rate District):	Docket No. R-2015-2518438
2017 UGI Gas Rate Case (former North Rate District):	Docket No. R-2016-2580030
2018 UGI Electric Rate Case	Docket No. R-2017-2640058
2019 UGI Gas Rate Case	Docket No. R-2018-3006814
2020 UGI Gas Rate Case	Docket No. R-2019-3015162

Education:

B.A. in International Politics, Pennsylvania State University

UGI Electric Exhibit TAH-2

UGI Utilities, Inc. - Electric Division
Default Service Filing: Effective June 1, 2025 - May 31, 2029
Annual Administrative Expense Allocation

Administrative Expenses Description	Rate Groups		
	GSR-1	GSR-2	Total
Outside Expenses[1]			
Outside Legal Expenses	$ 54,631	$ 7,869	$ 62,500
Consulting Services - Plan Development & Testimony	$ 32,779	$ 4,721	$ 37,500
Auction Manager	$ 131,116	$ 18,884	$ 150,000
Load Forecasting	$ 30,594	$ 4,406	$ 35,000
Company Expenses[2]			
Filing Costs - Salaries	$ 10,818	$ 1,558	$ 12,376
IT Support for Price to Compare and Relative Cost Factor Updates	$ 4,518	$ 651	$ 5,169
Supply Procurement	$ 6,168	$ -	$ 6,168
Load Research Meter Reading	$ 125,680	$ -	$ 125,680
Allocation of Supply Costs to Groups	$ 4,119	$ 593	$ 4,712
Hourly Billing - GSR-2 (Meter Reading)	$ -	$ 29,396	$ 29,396
Hourly Billing - GSR-2 (Large Customer Bill Preparation)	$ -	$ 56,476	$ 56,476
Total Annual Costs	$ 400,422	$ 124,554	$ 524,976
Total Annual Costs with GRT	$ 425,528	$ 132,363	$ 557,891

[1] Outside Expenses are estimates and will be amortized based on actual invoices received (reconcilable).

[2] Company Expenses will be amortized based on the amounts shown (non-reconcilable).