



UGI Utilities, Inc.
1 UGI Drive
Denver, PA 17517

Paul J. Szykman
Chief Regulatory Officer

May 30, 2025

VIA ELECTRONIC FILING

Mr. Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

**RE: UGI Utilities, Inc. – Gas Division,
Information Filed in Support of Purchased Gas Costs – 2025
Under 66 Pa. C.S. §1307(f) – May 30, 2025;
Docket No. R-2025-3054938**

Dear Secretary Homsher:

On behalf of UGI Utilities, Inc. – Gas Division (“UGI Gas”), please find enclosed for filing the annual Purchased Gas Cost pro forma tariff supplement, supporting information and prepared Direct Testimonies, filed pursuant to the provisions of 66 Pa. C.S. § 1307(f) and 52 Pa. Code § 53.64(a).

The enclosed pro forma tariff has a proposed effective date of December 1, 2025, and is filed in the form of a supplement as prescribed by the Pennsylvania Public Utility Commission’s (“Commission”) regulations at 52 Pa. Code § 53.64(e). The supporting documentation prescribed by the Commission’s regulations at 52 Pa. Code §§ 53.64(c) and 53.65 was filed with the Commission on May 1, 2025.

Notice

UGI Gas began issuing customer notices of this filing by bill insert on May 15, 2025. This process is expected to be completed by June 16, 2025. In addition, copies of this document have been served upon the persons indicated on the attached Certificate of Service.


Mr. Matthew L. Homsher, Secretary

May 30, 2025

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Inquiries concerning this tariff filing should be directed to Tracy Hazenstab, Sr. Manager – Utility Rates, either by phone at (814) 574-4168 or by email at thazenstab@ugi.com with copies to UGI Gas's counsel at the email addresses shown below.

Very truly yours,

DocuSigned by:

0D42C0CB3822401...
Paul J. Szykman

Enclosures: Supporting Information
Certificate of Service

cc: Service List

Michael S. Swerling, Esquire
UGI Corporation
500 North Gulph Road
King of Prussia, PA 19406
swerlingm@ugicorp.com

Lindsay A. Berkstresser, Esquire
UGI Corporation
500 North Gulph Road
King of Prussia, PA 19406
berkstresserl@ugicorp.com

CERTIFICATE OF SERVICE

I hereby certify that I have, this 30th day of May, 2025, 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):

VIA EMAIL:

Harrison W. Breitman, Esquire
Ryan Morden, Esquire
Assistant Consumer Advocates
Office Of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1921
ra-oca@paoca.org

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

Allison Kaster, Esquire
Director and Chief Prosecutor
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
akaster@pa.gov

DocuSigned by:



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Paul J. Szykman

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCKET NO. R–2025–3054938

COMPUTATION OF ANNUAL PURCHASED GAS COST FILING

SUBMITTED PURSUANT TO

52 PA. CODE §§ 53.64(c), AND 53.65

OF THE COMMISSION'S REGULATIONS

AND 66 PA. C. S. § 1317

IN SUPPORT OF

66 PA. C. S. § 1307(f) PURCHASED GAS COSTS – 2025

FILED MAY 30, 2025

UGI Utilities, Inc. – Gas Division
1307(f) Annual Purchased Gas Cost Filing – 2025
Docket No. R-2025-3054938

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Schedule B (Page 1) – Development of Projected Cost of Gas (C-factor)	K. M. Bassininsky
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<i>Pro Forma</i> Tariff Supplement to Gas – Pa. P.U.C. Nos. 7 and 7S	K. M. Bassininsky
UGI Gas Statement No. 1, Direct Testimony of Kimberly M. Bassininsky Principal Analyst – Rates	K. M. Bassininsky
Exhibit: UGI Gas Exhibit KMB-1	K. M. Bassininsky
UGI Gas Statement No. 2, Direct Testimony of Jesse R. Tyahla Director – FP&A and Strategic Modeling for UGI Corporation	J. R. Tyahla
Exhibit(s): UGI Gas Exhibit JRT-1 UGI Gas Exhibit JRT-2 UGI Gas Exhibit JRT-3 UGI Gas Exhibit JRT-4 UGI Gas Exhibit JRT-5	J. R. Tyahla

Book 1 – Filed May 1, 2025

Supporting Information Pursuant to 52 Pa. Code §§ 53.64(c) and 53.65, and 66 Pa. C.S. § 1317

		<u>Witness</u>
Section 1	§ 53.64(c)(1) Sources of Gas Supply¹	J. R. Tyahla
Section 1-A	§ 53.64(c)(1) Sources of Gas Supply²	J. R. Tyahla
	Attachment: 1-A-1 Experienced Volumes, Rates, Cost: 04/2024 – 03/2025	J. R. Tyahla
Section 1-B	§ 53.64(c)(1) Sources of Gas Supply³	J. R. Tyahla
	Attachments: 1-B-1 Projected Volumes, Rates, Cost: 04/2025 – 11/2025	J. R. Tyahla
	1-B-2 Projected Volumes, Rates, Cost: 12/2025 – 11/2026	J. R. Tyahla
Section 1-C	§ 53.64(c)(1) Sources of Gas Supply⁴	J. R. Tyahla
	Attachment: 1-C-1 Experienced and Projected Volumes: 04/2024 – 11/2026	J. R. Tyahla
Section 2-A	§ 53.64(c)(3) Other Sources of Gas Supply	J. R. Tyahla
	Attachments: 2-A-1 Spot Purchase Bids & Acceptances	J. R. Tyahla
	2-A-2 Upstream Transportation Activities	J. R. Tyahla
Section 2-B	§ 53.64(c)(3) Other Sources of Gas Supply	J. R. Tyahla
Section 3	§ 53.64(c)(4) FERC Proceedings	J. R. Tyahla
Section 4	§ 53.64(c)(5) Supply/Demand Projections	J. R. Tyahla
	Attachment: 4-1 Integrated Resource Plan Contract Year Supply/Demand Balance	J. R. Tyahla / K. M. Bassininsky
Section 5	§ 53.64(c)(6) Fuel Procurement Practices	J. R. Tyahla
	Attachment: 5-1 Organizational Chart	J. R. Tyahla
Section 6	§ 53.64(c)(7) Off-System Sales	J. R. Tyahla
Section 7	§ 53.64(c)(8) Transportation Agreements⁵	J. R. Tyahla
	Attachment: 7-1 Service Agreements	J. R. Tyahla
Section 8	§ 53.64(c)(9) End User Transportation Volume⁶	K. M. Bassininsky
Section 9	§ 53.64(c)(10) System Map	J. R. Tyahla
Section 10	§ 53.64(c)(11) Rate Structure Changes	K. M. Bassininsky

¹ Satisfies requirements of 52 Pa. Code § 60.8(3)

² Satisfies requirements of 52 Pa. Code § 60.8(3)

³ Satisfies requirements of 52 Pa. Code § 60.8(3)

⁴ Satisfies requirements of 52 Pa. Code § 60.8(3)

⁵ Satisfies requirements of 52 Pa. Code § 60.8(2)

⁶ Satisfies requirements of 52 Pa. Code § 60.8(1)

Section 11	§ 53.64(c)(12)-(14) Peak Day	J. R. Tyahla
Attachment:	11-1 Experienced 3-Day Peak Periods	J. R. Tyahla
Section 12	§ 53.64(i)(1) PGC Revenue/Expense	K. M. Bassininsky
Attachment:	12-1 PGC Revenue – Expense Statement	K. M. Bassininsky
Section 13	§ 53.65 Affiliated Purchases	J. R. Tyahla
Attachment:	13-1 Purchases from Affiliates	J. R. Tyahla
Section 14	66 Pa. C.S. § 1317(c) Reliability Plans	J. R. Tyahla
Attachments:	14-1 Capacity to Meet Firm Peak Day Requirements	J. R. Tyahla
	14-2 Load Duration Curve	J. R. Tyahla

**UGI Utilities, Inc. - Gas Division
Rider B - Purchased Gas Cost (PGC) Rates
Effective December 1, 2025**

Supporting Documentation

**UGI Utilities, Inc. - Gas Division
Computation of the Cost of Gas
Applicable to Rates: R, N, & GL**

**Effective December 1, 2025
Computation Year Ending November 30, 2026**

C - Projected Cost	\$	413,641,179
S - Projected Sales - Mcf		63,465,008
C/ S Projected Cost per Mcf	\$	6.5176
E - Experienced Cost	\$	(15,870,320)
-E / S Experienced Cost per Mcf 1/	\$	0.2501
PGC= (C/S + E/S) @ 12/1/2025 - (per Mcf)	\$	6.7677
Currently Effective PGC - (per Mcf) 2/	\$	6.6061
PGC Change (per Mcf)	\$	0.1616
Residential Heating Percent Change		1.1%

1/ See Schedule C, Page 1 for the development of this rate.

2/ See Supplement No. 57 to Tariff UGI Gas - Pa. P.U.C. No. 7, effective March 1, 2025.

UGI Utilities, Inc. - Gas Division
Development of the Projected Cost: C
For the 2025 PGC Year

Effective December 1, 2025
Computation Year Ending November 30, 2026

<u>Month</u>	<u>Year</u>	<u>Projected Sales (Mcf)</u> <u>S</u>	<u>Projected</u> <u>Revenue</u>	<u>Projected Cost</u> <u>C</u>	<u>Over/(Under)</u> <u>Collection</u>
December	2025	9,852,565	\$ 63,109,622 1/	\$ 61,006,739	\$ 2,102,883
January	2026	12,179,501	\$ 79,381,117	\$ 81,175,031	\$ (1,793,914)
February	2026	11,536,197	\$ 75,188,315	\$ 62,882,777	\$ 12,305,538
March	2026	9,947,263	\$ 64,832,279	\$ 54,443,583	\$ 10,388,696
April	2026	5,630,527	\$ 36,697,521	\$ 21,598,049	\$ 15,099,472
May	2026	2,749,023	\$ 17,917,032	\$ 15,541,229	\$ 2,375,803
June	2026	1,325,004	\$ 8,635,843	\$ 12,364,076	\$ (3,728,233)
July	2026	1,111,569	\$ 7,244,760	\$ 12,387,133	\$ (5,142,373)
August	2026	952,009	\$ 6,204,816	\$ 12,288,504	\$ (6,083,688)
September	2026	1,242,803	\$ 8,100,090	\$ 13,205,188	\$ (5,105,098)
October	2026	2,300,614	\$ 14,994,485	\$ 19,201,087	\$ (4,206,602)
November	2026	4,637,935	\$ 30,228,202	\$ 47,547,783	\$ (17,319,581)
Total		<u>63,465,008</u>	<u>\$ 412,534,081</u>	<u>\$ 413,641,179</u>	<u>\$ (1,107,098)</u>

1/ December 2025 reflects proration of the PGC rates.

UGI UTILITIES, INC. - GAS DIVISION
PROJECTED DEMAND UNIT RATE IN \$/DTH
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
DEMAND

	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	AVERAGE
Supply									
Options	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tetco FT-1 AMA Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Supplier B LNG Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Supplier B LNG Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Supplier A Delivered Supply	3.0263	3.1272	3.0263	3.1272	3.1272	3.0263	3.1272	3.0263	3.0768
Supplier A Delivered Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.9207
UGI Energy Svcs Delivered Supply	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929
UGI Energy Svcs Delivered Supply	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.8345	16.9000	16.8918
UGI Energy Svcs Delivered Supply	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	29.8931	3.7366
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.3052	3.9131
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.9999	4.0000
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	25.7709	3.2214
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	42.2823	5.2853
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	39.9999	5.0000
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.9999	4.0000
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	41.6386	5.2048
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	37.0079	4.6260
Supply TBD	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	50.0000	6.2500
Storage Demand									
Columbia FSS	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610
EGTS GSS	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782
Tetco SS-1	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862
Transco GSS	5.1636	5.3357	5.1636	5.3357	5.3357	5.1636	5.3357	5.1636	5.2497
Transco SS2	11.4540	11.8358	11.4540	11.8358	11.8358	11.4540	11.8358	11.4540	11.6449
Transco LSS	6.9618	7.1939	6.9618	7.1939	7.1939	6.9618	7.1939	6.9618	7.0778
Transco ESS	1.1496	1.1879	1.1496	1.1879	1.1879	1.1496	1.1879	1.1496	1.1688
Transco LGA	4.7895	4.9492	4.7895	4.9492	4.9492	4.7895	4.9492	4.7895	4.8693
UGI Storage Co. Service II	0.6000	0.6200	0.6000	0.6200	0.6200	0.6000	0.6200	0.6000	0.6100
Storage Capacity									
Columbia FSS	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160
EGTS GSS	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258
Tetco SS-1	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677
Transco GSS	0.0384	0.0397	0.0384	0.0397	0.0397	0.0384	0.0397	0.0384	0.0390
Transco SS2	0.0327	0.0338	0.0327	0.0338	0.0338	0.0327	0.0338	0.0327	0.0332
Transco LSS	0.0270	0.0279	0.0270	0.0279	0.0279	0.0270	0.0279	0.0270	0.0275
Transco ESS	0.1593	0.1646	0.1593	0.1646	0.1646	0.1593	0.1646	0.1593	0.1620
Transco LGA	0.9228	0.9536	0.9228	0.9536	0.9536	0.9228	0.9536	0.9228	0.9382
UGI Storage Co. Service II	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730
Transportation									
Columbia Gas SST	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600
Columbia Gas FTS	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630
Columbia Gas NTS	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380
EGTS FT	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622
EGTS FT	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622
EGTS FT	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622
Tennessee FT-A	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106
Tennessee FT-G	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136
Tennessee FT-G	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184
Tennessee FT-A	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184
Tetco FTS 5	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450
Tetco FT Riv	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760
Tetco FT Leb	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110
Tetco FT Leb	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214
Tetco FT Gulf	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595
Tetco FT Gulf	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208
Tetco FT Gulf-ELA	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880
Tetco CDS Leb	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340
Tetco CDS Gulf	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726
Tetco CDS Gulf	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310
Tetco FT M2-Delmont	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789
Tetco FT-1 (Cap. Release)	17.0550	17.6235	17.0550	17.6235	17.6235	17.0550	17.6235	17.0550	17.3393
Tetco FT-1 Appalachia	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626
Tetco FT-1 AMA	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359
Transco FT	23.1890	23.9620	23.1890	23.9620	23.9620	23.1890	23.9620	23.1890	23.5755
Transco FT	23.8496	24.6446	23.8496	24.6446	24.6446	23.8496	24.6446	23.8496	24.2471
Transco FTF	5.5941	5.7806	5.5941	5.7806	5.7806	5.5941	5.7806	5.5941	5.6873
Transco FT-PS	42.7440	44.1688	42.7440	44.1688	44.1688	42.7440	44.1688	42.7440	43.4564
Transco FT-Pocono	2.0091	2.0761	2.0091	2.0761	2.0761	2.0091	2.0761	2.0091	2.0426
Transco FT-Leidy South	15.0417	15.5431	15.0417	15.5431	15.5431	15.0417	15.5431	15.0417	15.2924
Transco FT-Sentinel	16.6098	17.1635	16.6098	17.1635	17.1635	16.6098	17.1635	16.6098	16.8866

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED PURCHASED GAS COSTS IN (\$)
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
DEMAND**

	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	TOTAL
Supply									
Options	221,760	275,949	273,550	299,508	297,205	274,393	270,628	456,385	\$ 2,369,378
Tetco FT-1 AMA Fee	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	\$ 5,061,336
Supplier B LNG Supply	0	0	0	0	0	0	0	0	\$ -
Supplier B LNG Supply	0	0	0	0	0	0	0	0	\$ -
Supplier A Delivered Supply	50,739	52,431	50,739	52,431	52,431	50,739	52,431	50,739	\$ 412,680
Supplier A Delivered Supply	0	0	0	0	0	0	0	61,828	\$ 61,828
UGI Energy Svcs Delivered Supply	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	\$ 2,717,867
UGI Energy Svcs Delivered Supply	777,383	777,383	777,383	777,383	777,383	777,383	774,368	1,656,099	\$ 7,094,766
UGI Energy Svcs Delivered Supply	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	\$ 3,105,324
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	0	\$ -
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	706,433	\$ 706,433
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	3,332,903	\$ 3,332,903
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	1,298,333	\$ 1,298,333
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	561,083	\$ 561,083
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	200,841	\$ 200,841
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	200,000	\$ 200,000
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	80,608	\$ 80,608
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	6,752,828	\$ 6,752,828
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	2,694,141	\$ 2,694,141
Supply TBD	0	0	0	0	0	0	0	898,150	\$ 898,150
Storage Demand									
Columbia FSS	817,142	817,142	817,142	817,142	817,142	817,142	817,142	817,142	\$ 6,537,136
EGTS GSS	180,334	180,334	180,334	180,334	180,334	180,334	180,334	180,334	\$ 1,442,671
Tetco SS-1	63,464	63,464	63,464	63,464	63,464	63,464	63,464	63,464	\$ 507,712
Transco GSS	306,604	316,824	306,604	316,824	316,824	306,604	316,824	306,604	\$ 2,493,714
Transco SS2	379,356	392,002	379,356	392,002	392,002	379,356	392,002	379,356	\$ 3,085,433
Transco LSS	52,339	54,083	52,339	54,083	54,083	52,339	54,083	52,339	\$ 425,689
Transco ESS	11,496	11,879	11,496	11,879	11,879	11,496	11,879	11,496	\$ 93,501
Transco LGA	4,957	5,122	4,957	5,122	5,122	4,957	5,122	4,957	\$ 40,318
UGI Storage Co. Service II	2,930	3,028	2,930	3,028	3,028	2,930	3,028	5,275	\$ 26,179
Storage Capacity									
Columbia FSS	817,863	817,863	817,863	817,863	817,863	817,863	817,863	817,863	\$ 6,542,902
EGTS GSS	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	\$ 921,920
Tetco SS-1	16,605	16,605	16,605	16,605	16,605	16,605	16,605	16,605	\$ 132,840
Transco GSS	111,613	115,333	111,613	115,333	115,333	111,613	115,333	111,613	\$ 907,785
Transco SS2	119,133	123,104	119,133	123,104	123,104	119,133	123,104	119,133	\$ 968,945
Transco LSS	22,330	23,075	22,330	23,075	23,075	22,330	23,075	22,330	\$ 181,621
Transco ESS	13,357	13,802	13,357	13,802	13,802	13,357	13,802	13,357	\$ 108,636
Transco LGA	3,820	3,948	3,820	3,948	3,948	3,820	3,948	3,820	\$ 31,073
UGI Storage Co. Service II	64,196	64,196	64,196	64,196	64,196	64,196	64,196	64,196	\$ 513,570
Transportation									
Columbia Gas SST	1,395,008	1,395,008	1,395,008	1,395,008	1,395,008	1,395,008	2,789,994	2,789,994	\$ 13,950,038
Columbia Gas FTS	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	\$ 21,521,486
Columbia Gas NTS	443,846	443,846	443,846	443,846	443,846	443,846	443,846	443,846	\$ 3,550,766
EGTS FT	11,924	11,924	11,924	11,924	11,924	11,924	11,924	11,924	\$ 95,395
EGTS FT	0	0	0	0	0	0	0	11,924	\$ 11,924
EGTS FT	0	0	0	0	0	0	0	337,860	\$ 337,860
Tennessee FT-A	187,360	187,360	187,360	187,360	187,360	187,360	187,360	187,360	\$ 1,498,883
Tennessee FT-G	15,016	7,508	6,257	5,005	5,005	7,508	8,947	10,549	\$ 65,797
Tennessee FT-G	0	0	0	0	0	0	0	4,055	\$ 4,055
Tennessee FT-A	13,745	13,745	13,745	13,745	13,745	13,745	13,745	13,745	\$ 109,964
Tetco FTS 5	48,302	48,302	48,302	48,302	48,302	48,302	48,302	48,302	\$ 386,419
Tetco FT Riv	59,504	59,504	59,504	59,504	59,504	59,504	59,504	59,504	\$ 476,032
Tetco FT Leb	870,288	870,288	870,288	870,288	870,288	870,288	870,288	870,288	\$ 6,962,303
Tetco FT Leb	51,685	51,685	51,685	51,685	51,685	51,685	51,685	51,685	\$ 413,484
Tetco FT Gulf	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	\$ 11,016,578
Tetco FT Gulf	28,196	28,196	28,196	28,196	28,196	28,196	28,196	28,196	\$ 225,572
Tetco FT Gulf-ELA	244,656	244,656	244,656	244,656	244,656	244,656	244,656	244,656	\$ 1,957,248
Tetco CDS Leb	153,340	153,340	153,340	153,340	153,340	153,340	153,340	153,340	\$ 1,226,720
Tetco CDS Gulf	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	\$ 12,921,533
Tetco CDS Gulf	204,371	204,371	204,371	204,371	204,371	204,371	204,371	204,371	\$ 1,634,965
Tetco FT M2-Delmont	23,360	23,360	23,360	23,360	23,360	23,360	23,360	23,360	\$ 186,882
Tetco FT-1 (Cap. Release)	255,876	264,405	255,876	264,405	264,405	255,876	264,405	255,876	\$ 2,081,126
Tetco FT-1 Appalachia	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	\$ 2,500,214
Tetco FT-1 AMA	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	\$ 2,927,590
Transco FT	721,016	745,049	721,016	745,049	745,049	721,016	745,049	721,016	\$ 5,864,260
Transco FT	108,897	112,527	108,897	112,527	112,527	108,897	112,527	108,897	\$ 885,698
Transco FTF	127,378	131,624	127,378	131,624	131,624	127,378	131,624	127,378	\$ 1,036,005
Transco FT-PS	0	0	0	0	0	0	0	0	\$ -
Transco FT-Pocono	4,018	4,152	4,018	4,152	4,152	4,018	4,152	4,018	\$ 32,681
Transco FT-Leidy South	36,100	37,303	36,100	37,303	37,303	36,100	37,303	36,100	\$ 293,614
Transco FT-Sentinel	116,269	120,144	116,269	120,144	120,144	116,269	120,144	116,269	\$ 945,651
SUBTOTAL	\$ 16,994,311	\$ 17,122,599	\$ 17,037,341	\$ 17,143,656	\$ 17,141,353	\$ 17,039,436	\$ 18,510,689	\$ 36,641,503	\$ 157,630,887
Non-Choice Cap Rel/Sharing Mech Credit	(924,490)	(460,540)	(444,597)	(445,300)	(444,262)	(455,668)	(454,432)	(395,687)	\$ (4,024,975)
Choice Capacity Assignment Credits	(2,626,381)	(2,641,499)	(2,624,594)	(2,640,988)	(2,640,988)	(2,624,849)	(2,925,783)	(6,601,907)	\$ (25,326,989)
Transportation Credits	(3,347,048)	(3,347,048)	(3,347,048)	(3,347,048)	(3,347,048)	(3,347,048)	(3,347,048)	(3,347,048)	\$ (26,776,383)
Balancing Service Credit	(602,938)	(364,433)	(265,867)	(300,540)	(384,494)	(257,673)	(276,769)	(436,214)	\$ (2,888,928)
Administrative Costs	46,491	46,491	46,491	46,491	46,491	46,491	46,491	46,491	\$ 371,927
Total Demand Cost	\$ 9,539,945	\$ 10,355,571	\$ 10,401,726	\$ 10,456,271	\$ 10,371,052	\$ 10,400,688	\$ 11,553,149	\$ 25,907,139	\$ 98,985,540

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED SUPPLY VOLUMES IN DTH OR DTH/D
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
COMMODITY**

	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	TOTAL
<u>Supply Volumes</u>									
Term M2	702,870	711,171	675,570	721,184	762,383	698,400	687,580	705,390	5,664,548
Term Leidy	284,490	669,011	648,030	653,883	630,013	609,690	568,354	439,050	4,502,521
Term A06	132,210	58,962	114,390	120,807	52,204	34,440	2,418	115,590	631,021
Term Z4 Marcellus	146,910	173,011	99,690	108,531	128,247	123,450	142,352	246,060	1,168,251
Term Z4 St. 219	30,090	31,093	30,090	31,093	31,093	30,090	31,093	45,150	259,792
Term Z4 St. 313	120,000	116,157	87,000	80,693	75,888	61,050	59,737	50,730	651,255
Mo Dlvd Tetco Supply	600,000	310,000	225,000	155,000	155,000	225,000	310,000	600,000	2,580,000
Mo Dlvd Leidy	900,000	310,000	225,000	155,000	155,000	225,000	310,000	900,000	3,180,000
Mo Dlvd Z4 300L	150,000	155,000	150,000	93,000	93,000	150,000	155,000	150,000	1,096,000
Mo Dlvd Z4 300L (2)	60,000	0	0	0	0	0	0	60,000	120,000
Spot M2	1,162,412	557,191	209,235	197,197	177,553	347,588	1,332,219	1,641,845	5,625,240
Spot Leidy	348,723	167,157	62,770	59,159	53,266	104,276	399,666	492,554	1,687,571
Spot A06	581,206	278,595	104,617	98,599	88,777	173,794	666,110	820,923	2,812,621
Spot Z4 Marcellus	232,482	111,438	41,847	39,439	35,511	69,518	266,444	328,369	1,125,048
Spot Transco Gulf	0	0	0	0	0	0	0	0	0
Asset Management Refill	1,361,405	1,361,405	1,361,405	1,361,405	1,361,405	1,361,405	1,361,405	0	9,529,835
<u>Withdrawn Volumes</u>									
EGTS GSS	0	0	0	0	0	0	0	170,000	170,000
Tetco SS1	0	0	0	0	0	0	0	0	0
Transco GSS	0	0	0	0	0	0	0	0	0
Transco SS-2	0	0	0	0	0	0	0	0	0
Transco LSS	0	0	0	0	0	0	0	0	0
Transco ESS	0	0	0	0	0	0	0	0	0
Transco LGA	0	0	0	0	0	0	0	0	0
UGI Storage Co. Service II	0	0	0	0	0	0	0	79,847	79,847
TCO FSS	0	0	0	0	0	0	0	0	0
<u>Injected Volumes</u>									
EGTS GSS	560,454	638,923	637,052	638,922	638,922	637,053	638,692	0	4,390,018
Tetco SS1	8,132	86,335	83,550	86,335	86,335	59,250	51,398	0	461,335
Transco GSS	217,440	472,688	458,250	452,665	421,011	407,430	339,538	0	2,769,022
Transco SS-2	492,720	509,144	492,720	509,144	509,144	492,720	509,158	0	3,514,750
Transco LSS	100,440	103,788	100,440	103,788	103,788	100,440	103,788	0	716,472
Transco ESS	11,130	11,501	11,130	11,501	11,501	11,130	11,501	0	79,394
Transco LGA	0	0	0	0	0	0	0	0	0
UGI Storage Co. Service II	112,500	139,500	106,400	99,200	93,000	90,000	76,836	0	717,436
TCO FSS	728,773	876,066	876,066	876,066	876,066	876,066	876,067	0	5,985,170
Total Demand Served	4,581,209	2,172,246	1,269,036	1,097,369	1,059,573	1,539,612	3,685,400	6,771,588	22,176,033
Total Choice Bundled Demand	0	0	0	0	0	0	0	73,920	73,920

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED SUPPLY UNIT RATE IN \$/DTH
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
COMMODITY**

	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	AVERAGE
<u>Supply Rate</u>									
Term M2	3.2947	2.1649	2.3546	2.5984	2.6565	2.2497	2.1775	2.7529	2.5311
Term Leidy	3.2776	2.1460	2.3159	2.6229	2.6736	2.2058	2.1486	2.7977	2.5235
Term A06	3.3492	2.3382	2.4993	2.7615	2.8304	2.4681	2.4181	2.7992	2.6830
Term Z4 Marcellus	3.2848	2.1161	2.2783	2.6153	2.6811	2.2110	2.0759	2.7926	2.5069
Term Z4 St. 219	3.5284	2.4074	2.5244	2.8213	2.9247	2.4571	2.4049	3.0764	2.7681
Term Z4 St. 313	3.4628	2.3783	2.5280	2.7850	2.8586	2.6279	2.6261	2.7852	2.7565
Mo Dlvd Tetco Supply	3.2947	2.1649	2.3546	2.5984	2.6565	2.2497	2.1775	2.7529	2.5311
Mo Dlvd Leidy	3.2776	2.1460	2.3159	2.6229	2.6736	2.2058	2.1486	2.7977	2.5235
Mo Dlvd Z4 300L	3.2848	2.1161	2.2783	2.6153	2.6811	2.2110	2.0759	2.7926	2.5069
Mo Dlvd Z4 300L (2)	3.3348	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.8426	0.7722
Spot M2	3.2947	2.1649	2.3546	2.5984	2.6565	2.2497	2.1775	2.7529	2.5311
Spot Leidy	3.2776	2.1460	2.3159	2.6229	2.6736	2.2058	2.1486	2.7977	2.5235
Spot A06	3.3492	2.3382	2.4993	2.7615	2.8304	2.4681	2.4181	2.7992	2.6830
Spot Z4 Marcellus	3.2848	2.1161	2.2783	2.6153	2.6811	2.2110	2.0759	2.7926	2.5069
Spot Transco Gulf	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Asset Management Refill	3.3218	2.6208	2.7694	2.9891	3.0542	3.0206	3.0796	0.0000	2.6069
<u>Withdrawal Rate</u>									
EGTS GSS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0272	0.0034
Tetco SS1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco GSS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco SS-2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco LSS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco ESS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco LGA	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Storage Co. Service II	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0014	0.0002
TCO FSS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
<u>Injection Rate</u>									
EGTS GSS	0.0402	0.0402	0.0402	0.0402	0.0402	0.0402	0.0402	0.0000	0.0352
Tetco SS1	0.0350	0.0350	0.0350	0.0350	0.0350	0.0350	0.0350	0.0000	0.0306
Transco GSS	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0000	0.0718
Transco SS-2	0.0395	0.0395	0.0395	0.0395	0.0395	0.0395	0.0395	0.0000	0.0346
Transco LSS	0.0489	0.0489	0.0489	0.0489	0.0489	0.0489	0.0489	0.0000	0.0428
Transco ESS	0.1075	0.1075	0.1075	0.1075	0.1075	0.1075	0.1075	0.0000	0.0941
Transco LGA	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Storage Co. Service II	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
TCO FSS	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0000	0.0291
Total Com Vol	4,581,209	2,172,246	1,269,036	1,097,369	1,059,573	1,539,612	3,685,400	6,771,588	22,176,033
Total Com Cost	\$ 10,550,753	\$ 2,636,283	\$ 854,987	\$ 314,318	\$ 189,725	\$ 1,862,822	\$ 6,761,016	\$ 16,638,316	\$ 39,808,219
Com Unit Rate	\$ 2.30	\$ 1.21	\$ 0.67	\$ 0.29	\$ 0.18	\$ 1.21	\$ 1.83	\$ 2.46	\$ 1.80
Total Dem Cost	\$ 9,539,945	\$ 10,355,571	\$ 10,401,726	\$ 10,456,271	\$ 10,371,052	\$ 10,400,688	\$ 11,553,149	\$ 25,907,139	\$ 98,985,540
Dem Unit Rate	\$ 2.08	\$ 4.77	\$ 8.20	\$ 9.53	\$ 9.79	\$ 6.76	\$ 3.13	\$ 3.83	\$ 4.46
Total System Costs	\$ 20,090,698	\$ 12,991,854	\$ 11,256,713	\$ 10,770,589	\$ 10,560,777	\$ 12,263,509	\$ 18,314,165	\$ 42,545,455	\$ 138,793,759
System Unit Rate	\$ 4.39	\$ 5.98	\$ 8.87	\$ 9.81	\$ 9.97	\$ 7.97	\$ 4.97	\$ 6.28	\$ 6.26

UGI UTILITIES, INC. - GAS DIVISION
PROJECTED PURCHASE GAS COSTS IN (\$)
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
COMMODITY

	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	TOTAL
Supply Cost									
Term M2	2,315,713	1,539,632	1,590,664	1,873,893	2,025,307	1,571,194	1,497,183	1,941,844	\$ 14,355,432
Term Leidy	932,440	1,435,724	1,500,754	1,715,054	1,684,418	1,344,874	1,221,138	1,228,344	\$ 11,062,745
Term A06	442,800	137,868	285,894	333,606	147,760	85,002	5,847	323,556	\$ 1,762,333
Term Z4 Marcellus	482,577	366,106	227,125	283,845	343,847	272,950	295,509	687,155	\$ 2,959,114
Term Z4 St. 219	106,171	74,853	75,960	87,721	90,939	73,935	74,775	138,900	\$ 723,254
Term Z4 St. 313	415,542	276,252	219,940	224,730	216,936	160,433	156,874	141,293	\$ 1,811,999
Mo Dlvd Tetco Supply	1,976,792	671,127	529,774	402,745	411,765	506,184	675,015	1,651,720	\$ 6,825,122
Mo Dlvd Leidy	2,949,825	665,272	521,071	406,546	414,412	496,312	666,051	2,517,959	\$ 8,637,448
Mo Dlvd Z4 300L	492,727	327,993	341,748	243,226	249,345	331,652	321,765	418,895	\$ 2,727,351
Mo Dlvd Z4 300L (2)	200,091	0	0	0	0	0	0	170,558	\$ 370,649
Spot M2	3,829,745	1,206,277	492,655	512,388	471,678	781,971	2,900,863	4,519,779	\$ 14,715,356
Spot Leidy	1,142,969	358,725	145,367	155,167	142,413	230,015	858,703	1,378,034	\$ 4,411,394
Spot A06	1,946,585	651,424	261,468	272,279	251,278	428,944	1,610,725	2,297,901	\$ 7,720,605
Spot Z4 Marcellus	763,668	235,813	95,341	103,146	95,210	153,705	553,113	917,014	\$ 2,917,008
Spot Transco Gulf	0	0	0	0	0	0	0	0	\$ -
Asset Management Refill	4,522,259	3,568,030	3,770,233	4,069,381	4,158,018	4,112,315	4,192,642	0	\$ 28,392,879
Withdrawal Cost									
EGTS GSS	0	0	0	0	0	0	0	4,624	\$ 4,624
Tetco SS1	0	0	0	0	0	0	0	0	\$ -
Transco GSS	0	0	0	0	0	0	0	0	\$ -
Transco SS-2	0	0	0	0	0	0	0	0	\$ -
Transco LSS	0	0	0	0	0	0	0	0	\$ -
Transco ESS	0	0	0	0	0	0	0	0	\$ -
Transco LGA	0	0	0	0	0	0	0	0	\$ -
UGI Storage Co. Service II	0	0	0	0	0	0	0	112	\$ 112
TCO FSS	0	0	0	0	0	0	0	0	\$ -
Injection Cost									
EGTS GSS	22,530	25,685	25,609	25,685	25,685	25,610	25,675	0	\$ 176,479
Tetco SS1	285	3,022	2,924	3,022	3,022	2,074	1,799	0	\$ 16,147
Transco GSS	17,832	38,765	37,581	37,123	34,527	33,413	27,846	0	\$ 227,087
Transco SS-2	19,467	20,116	19,467	20,116	20,116	19,467	20,117	0	\$ 138,868
Transco LSS	4,915	5,078	4,915	5,078	5,078	4,915	5,078	0	\$ 35,057
Transco ESS	1,197	1,237	1,197	1,237	1,237	1,197	1,237	0	\$ 8,536
Transco LGA	0	0	0	0	0	0	0	0	\$ -
UGI Storage Co. Service II	0	0	0	0	0	0	0	0	\$ -
TCO FSS	24,268	29,173	29,173	29,173	29,173	29,173	29,173	0	\$ 199,306
Subtotal Cost	\$ 22,610,398	\$ 11,638,173	\$ 10,178,859	\$ 10,805,161	\$ 10,822,163	\$ 10,665,334	\$ 15,141,128	\$ 18,337,688	\$ 110,198,904
Injected Value	\$ (9,464,648)	\$ (7,794,414)	\$ (8,164,785)	\$ (9,075,646)	\$ (9,161,419)	\$ (8,105,369)	\$ (7,930,806)	\$ -	\$ (59,697,086)
Withdrawal Value	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 642,975	\$ 642,975
Choice Bundled Sale Credit	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (212,812)	\$ (212,812)
Net Financial Derivatives	\$ (2,594,997)	\$ (1,207,477)	\$ (1,159,087)	\$ (1,415,197)	\$ (1,471,019)	\$ (697,144)	\$ (449,306)	\$ (2,129,535)	\$ (11,123,761)
Total Cost	\$ 10,550,753	\$ 2,636,283	\$ 854,987	\$ 314,318	\$ 189,725	\$ 1,862,822	\$ 6,761,016	\$ 16,638,316	\$ 39,808,219

UGI UTILITIES, INC. - GAS DIVISION
PROJECTED DEMAND UNIT RATE IN \$/DTH
UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
DEMAND

	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	AVERAGE
Supply													
Options	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tetco FT-1 AMA Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Supplier B LNG Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Supplier B LNG Supply	34.0000	34.0000	32.6500	34.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	11.2208
Supplier A Delivered Supply	3.1272	3.1272	2.8246	3.1272	3.0263	3.1272	3.0263	3.1272	3.1272	3.0263	3.1272	3.0263	3.0684
Supplier A Delivered Supply	7.3657	7.3657	7.3657	7.3657	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	7.3657
UGI Energy Svcs Delivered Supply	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929
UGI Energy Svcs Delivered Supply	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.8345	16.9000	16.8945
UGI Energy Svcs Delivered Supply	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266
UGI Energy Svcs Peaking Supply	59.7500	59.7500	59.7500	59.7500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	19.9167
UGI Energy Svcs Peaking Supply	29.8931	29.8931	29.8931	29.8931	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	29.8931	12.4554
UGI Energy Svcs Peaking Supply	31.3052	31.3052	31.3052	31.3052	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.3052	13.0438
UGI Energy Svcs Peaking Supply	31.9999	31.9999	31.9999	31.9999	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.9999	13.3333
UGI Energy Svcs Peaking Supply	25.7709	25.7709	25.7709	25.7709	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	25.7709	10.7379
UGI Energy Svcs Peaking Supply	42.2823	42.2823	42.2823	42.2823	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	42.2823	17.6176
UGI Energy Svcs Peaking Supply	39.9999	39.9999	39.9999	39.9999	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	39.9999	16.6666
UGI Energy Svcs Peaking Supply	31.9999	31.9999	31.9999	31.9999	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.9999	13.3333
UGI Energy Svcs Peaking Supply	41.6386	41.6386	41.6386	41.6386	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	41.6386	17.3494
UGI Energy Svcs Peaking Supply	37.0079	37.0079	37.0079	37.0079	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	37.0079	15.4200
Supply TBD	50.0000	50.0000	50.0000	50.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	50.0000	20.8333
Storage Demand													
Columbia FSS	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610	6.4610
EGTS GSS	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782	2.6782
Tetco SS-1	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862	8.2862
Tranco GSS	5.3357	5.3357	4.8194	5.3357	5.1636	5.3357	5.1636	5.3357	5.3357	5.1636	5.3357	5.1636	5.2353
Tranco SS2	11.8358	11.8358	10.6904	11.8358	11.4540	11.8358	11.4540	11.8358	11.8358	11.4540	11.8358	11.4540	11.6131
Tranco LSS	7.1939	7.1939	6.4977	7.1939	6.9618	7.1939	6.9618	7.1939	7.1939	6.9618	7.1939	6.9618	7.0585
Tranco ESS	1.1879	1.1879	1.0730	1.1879	1.1496	1.1879	1.1496	1.1879	1.1879	1.1496	1.1879	1.1496	1.1656
Tranco LGA	4.9492	4.9492	4.4702	4.9492	4.7895	4.9492	4.7895	4.9492	4.9492	4.7895	4.9492	4.7895	4.8560
UGI Storage Co. Service II	0.6200	0.6200	0.5600	0.6200	0.6000	0.6200	0.6000	0.6200	0.6200	0.6000	0.6200	0.6000	0.6083
Storage Capacity													
Columbia FSS	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160	0.1160
EGTS GSS	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258
Tetco SS-1	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677	0.3677
Tranco GSS	0.0397	0.0397	0.0358	0.0397	0.0384	0.0397	0.0384	0.0397	0.0397	0.0384	0.0397	0.0384	0.0389
Tranco SS2	0.0338	0.0338	0.0305	0.0338	0.0327	0.0338	0.0327	0.0338	0.0338	0.0327	0.0338	0.0327	0.0332
Tranco LSS	0.0279	0.0279	0.0252	0.0279	0.0270	0.0279	0.0270	0.0279	0.0279	0.0270	0.0279	0.0270	0.0274
Tranco ESS	0.1646	0.1646	0.1487	0.1646	0.1593	0.1646	0.1593	0.1646	0.1646	0.1593	0.1646	0.1593	0.1615
Tranco LGA	0.9536	0.9536	0.8613	0.9536	0.9228	0.9536	0.9228	0.9536	0.9536	0.9228	0.9536	0.9228	0.9356
UGI Storage Co. Service II	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730
Transportation													
Columbia Gas SST	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600	22.0600
Columbia Gas FTS	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630	22.0630
Columbia Gas NTS	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380	22.7380
EGTS FT	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622
EGTS FT	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622
EGTS FT	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622	5.9622
Tennessee FT-A	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106	5.5106
Tennessee FT-G	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136	12.5136
Tennessee FT-G	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184
Tennessee FT-A	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184	4.3184
Tetco FTS 5	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450	7.2450
Tetco FT Riv	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760	14.8760
Tetco FT Leb	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110	15.1110
Tetco FT Leb	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214	12.9214
Tetco FT Gulf	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595	23.9595
Tetco FT Gulf	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208	24.8208
Tetco FT Gulf-ELA	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880	20.3880
Tetco CDS Leb	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340	15.3340
Tetco CDS Gulf	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726	24.4726
Tetco CDS Gulf	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310	25.3310
Tetco FT M2-Delmont	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789	7.0789
Tetco FT-1 (Cap. Release)	17.6235	17.6235	15.9180	17.6235	17.0550	17.6235	17.0550	17.6235	17.6235	17.0550	17.6235	17.0550	17.2919
Tetco FT-1 Appalachia	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626
Tetco FT-1 AMA	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359
Tranco FT	23.9620	23.9620	21.6431	23.9620	23.1890	23.9620	23.1890	23.9620	23.9620	23.1890	23.9620	23.1890	23.5111
Tranco FT	24.6446	24.6446	22.2596	24.6446	23.8496	24.6446	23.8496	24.6446	24.6446	23.8496	24.64		

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED PURCHASED GAS COSTS IN (\$)
UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
DEMAND**

	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	TOTAL
Supply													
Options	606,268	926,660	656,915	424,552	221,760	275,949	273,550	299,508	297,205	274,393	270,628	456,385	\$ 4,983,772
Tetco FT-1 AMA Fee	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	\$ 7,592,004
Supplier B LNG Supply	77,500	77,500	71,500	77,500	0	0	0	0	0	0	0	0	\$ 304,000
Supplier B LNG Supply	340,000	340,000	326,500	340,000	0	0	0	0	0	0	0	0	\$ 1,346,500
Supplier A Delivered Supply	52,431	52,431	47,357	52,431	50,739	52,431	50,739	52,431	52,431	50,739	52,431	50,739	\$ 617,328
Supplier A Delivered Supply	61,828	61,828	61,828	61,828	0	0	0	0	0	0	0	0	\$ 309,140
UGI Energy Svcs Delivered Supply	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	\$ 4,076,801
UGI Energy Svcs Delivered Supply	1,656,099	1,656,099	1,656,099	1,656,099	1,656,099	1,656,099	1,656,099	1,656,099	1,656,099	1,656,099	1,656,099	1,656,099	\$ 13,719,160
UGI Energy Svcs Delivered Supply	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	\$ 4,657,987
UGI Energy Svcs Peaking Supply	2,390,000	2,390,000	2,390,000	2,390,000	0	0	0	0	0	0	0	0	\$ 9,560,000
UGI Energy Svcs Peaking Supply	706,433	706,433	706,433	706,433	0	0	0	0	0	0	0	706,433	\$ 3,532,165
UGI Energy Svcs Peaking Supply	3,332,903	3,332,903	3,332,903	3,332,903	0	0	0	0	0	0	0	3,332,903	\$ 16,664,516
UGI Energy Svcs Peaking Supply	1,298,333	1,298,333	1,298,333	1,298,333	0	0	0	0	0	0	0	1,298,333	\$ 6,491,664
UGI Energy Svcs Peaking Supply	561,083	561,083	561,083	561,083	0	0	0	0	0	0	0	561,083	\$ 2,805,416
UGI Energy Svcs Peaking Supply	200,841	200,841	200,841	200,841	0	0	0	0	0	0	0	200,841	\$ 1,004,204
UGI Energy Svcs Peaking Supply	200,000	200,000	200,000	200,000	0	0	0	0	0	0	0	200,000	\$ 999,998
UGI Energy Svcs Peaking Supply	80,608	80,608	80,608	80,608	0	0	0	0	0	0	0	80,608	\$ 403,039
UGI Energy Svcs Peaking Supply	6,752,828	6,752,828	6,752,828	6,752,828	0	0	0	0	0	0	0	6,752,828	\$ 33,764,142
UGI Energy Svcs Peaking Supply	2,694,141	2,694,141	2,694,141	2,694,141	0	0	0	0	0	0	0	2,694,141	\$ 13,470,707
Supply TBD	898,150	898,150	898,150	898,150	0	0	0	0	0	0	0	1,521,800	\$ 5,114,400
Storage Demand													
Columbia FSS	817,142	817,142	817,142	817,142	817,142	817,142	817,142	817,142	817,142	817,142	817,142	817,142	\$ 9,805,705
EGTS GSS	180,334	180,334	180,334	180,334	180,334	180,334	180,334	180,334	180,334	180,334	180,334	180,334	\$ 2,164,007
Tetco SS-1	63,464	63,464	63,464	63,464	63,464	63,464	63,464	63,464	63,464	63,464	63,464	63,464	\$ 761,568
Tranco GSS	316,824	316,824	286,164	316,824	306,604	316,824	306,604	316,824	316,824	316,824	306,604	316,824	\$ 3,730,352
Tranco SS2	392,002	392,002	354,066	392,002	379,356	392,002	379,356	392,002	392,002	379,356	392,002	379,356	\$ 4,615,504
Tranco LSS	54,083	54,083	48,850	54,083	52,339	54,083	52,339	54,083	54,083	52,339	54,083	52,339	\$ 636,789
Tranco ESS	11,879	11,879	10,730	11,879	11,496	11,879	11,496	11,879	11,879	11,496	11,879	11,496	\$ 139,868
Tranco LGA	5,122	5,122	4,627	5,122	4,957	5,122	4,957	5,122	5,122	4,957	5,122	4,957	\$ 60,312
UGI Storage Co. Service II	5,451	5,451	4,924	5,451	2,930	3,028	2,930	3,028	3,028	2,930	3,028	2,930	\$ 47,455
Storage Capacity													
Columbia FSS	817,863	817,863	817,863	817,863	817,863	817,863	817,863	817,863	817,863	817,863	817,863	817,863	\$ 9,814,353
EGTS GSS	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	\$ 1,382,880
Tetco SS-1	16,605	16,605	16,605	16,605	16,605	16,605	16,605	16,605	16,605	16,605	16,605	16,605	\$ 199,261
Tranco GSS	115,333	115,333	104,172	115,333	111,613	115,333	111,613	115,333	115,333	111,613	115,333	111,613	\$ 1,357,957
Tranco SS2	123,104	123,104	111,190	123,104	119,133	123,104	119,133	123,104	123,104	119,133	123,104	119,133	\$ 1,449,447
Tranco LSS	23,075	23,075	20,842	23,075	22,330	23,075	22,330	23,075	23,075	22,330	23,075	22,330	\$ 271,687
Tranco ESS	13,802	13,802	12,466	13,802	13,357	13,802	13,357	13,802	13,802	13,357	13,802	13,357	\$ 162,508
Tranco LGA	3,948	3,948	3,566	3,948	3,820	3,948	3,820	3,948	3,948	3,820	3,948	3,820	\$ 46,481
UGI Storage Co. Service II	64,196	64,196	64,196	64,196	64,196	64,196	64,196	64,196	64,196	64,196	64,196	64,196	\$ 770,355
Transportation													
Columbia Gas SST	2,789,994	2,789,994	2,789,994	2,789,994	1,395,008	1,395,008	1,395,008	1,395,008	1,395,008	1,395,008	2,789,994	2,789,994	\$ 25,110,016
Columbia Gas FTS	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	2,690,186	\$ 32,282,229
Columbia Gas NTS	443,846	443,846	443,846	443,846	443,846	443,846	443,846	443,846	443,846	443,846	443,846	443,846	\$ 5,326,149
EGTS FT	11,924	11,924	11,924	11,924	11,924	11,924	11,924	11,924	11,924	11,924	11,924	11,924	\$ 143,093
EGTS FT	11,924	11,924	11,924	11,924	0	0	0	0	0	0	0	11,924	\$ 59,622
EGTS FT	337,860	337,860	337,860	337,860	0	0	0	0	0	0	0	337,860	\$ 1,689,300
Tennessee FT-A	187,360	187,360	187,360	187,360	187,360	187,360	187,360	187,360	187,360	187,360	187,360	187,360	\$ 2,248,325
Tennessee FT-G	10,937	10,399	11,137	12,726	15,016	7,508	6,257	5,005	7,508	8,947	7,508	8,947	\$ 110,996
Tennessee FT-G	7,786	8,870	7,920	5,515	0	0	0	0	0	0	0	4,055	\$ 34,146
Tennessee FT-A	13,745	13,745	13,745	13,745	13,745	13,745	13,745	13,745	13,745	13,745	13,745	13,745	\$ 164,946
Tetco FTS 5	48,302	48,302	48,302	48,302	48,302	48,302	48,302	48,302	48,302	48,302	48,302	48,302	\$ 579,629
Tetco FT Riv	59,504	59,504	59,504	59,504	59,504	59,504	59,504	59,504	59,504	59,504	59,504	59,504	\$ 714,048
Tetco FT Leb	870,288	870,288	870,288	870,288	870,288	870,288	870,288	870,288	870,288	870,288	870,288	870,288	\$ 10,443,454
Tetco FT Leb	51,685	51,685	51,685	51,685	51,685	51,685	51,685	51,685	51,685	51,685	51,685	51,685	\$ 620,226
Tetco FT Gulf	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	1,377,072	\$ 16,524,867
Tetco FT Gulf	28,196	28,196	28,196	28,196	28,196	28,196	28,196	28,196	28,196	28,196	28,196	28,196	\$ 338,357
Tetco FT Gulf-ELA	244,656	244,656	244,656	244,656	244,656	244,656	244,656	244,656	244,656	244,656	244,656	244,656	\$ 2,935,872
Tetco CDS Leb	153,340	153,340	153,340	153,340	153,340	153,340	153,340	153,340	153,340	153,340	153,340	153,340	\$ 1,840,080
Tetco CDS Gulf	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	1,615,192	\$ 19,382,299
Tetco CDS Gulf	204,371	204,371	204,371	204,371	204,371	204,371	204,371	204,371	204,371	204,371	204,371	204,371	\$ 2,452,448
Tetco FT M2-Delmont	23,360	23,360	23,360	23,360	23,360	23,360	23,360	23,360	23,360	23,360	23,360	23,360	\$ 280,323
Tetco FT-1 (Cap. Release)	264,405	264,405	238,818	264,405	255,876	264,405	255,876	264,405	264,405	255,876	264,405	255,876	\$ 3,113,160
Tetco FT-1 Appalachia	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	\$ 3,750,322
Tetco FT-1 AMA	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	\$ 4,391,386
Tranco FT	742,150	742,150	670,329	745,049	721,016	745,049	721,016	745,049	745,049	721,016	745,049	721,016	\$ 8,763,939
Tranco FT	112,527	112,527	101,637	112,527	108,897	112,527	108,897	112,527	112,527	108,897	112,527	108,897	\$ 1,324,917
Tranco FTF	131,624	131,624	118,886	131,624	127,378	131,624	127,378	131,624	131,624	127,378	131,624	127,378	\$ 1,549,761
Tranco FT-PS	229,413	229,413	207,212	0	0	0	0	0	0	0	0	0	\$ 666,037
Tranco FT-Pocono	4,152	4,152	3,750	4,152	4,018	4,152	4,018	4,152	4,018	4,152	4,018	4,152	\$ 48,888
Tranco FT-Leidy South	37,303	37,303	33,693	37,303	36,100	37,303	36,100	37,303	37,303	36,100	37,303	36,100	\$ 439,218
Tranco FT-Sentinel	120,144	120,144	108,517</										

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED SUPPLY VOLUMES IN DTH OR DTH/D
UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
COMMODITY**

	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	TOTAL
Supply Volumes													
Term M2	1,074,274	940,354	1,080,604	814,401	702,870	711,171	675,570	721,184	762,383	698,400	687,580	705,390	9,574,181
Term Leidy	486,979	680,543	473,592	520,893	284,490	669,011	648,030	653,883	630,013	609,690	568,354	439,050	6,664,528
Term A06	270,351	323,919	276,304	251,968	132,210	58,962	114,390	120,807	52,204	34,440	2,418	115,590	1,753,563
Term Z4 Marcellus	263,810	460,164	361,340	252,495	146,910	173,011	99,690	108,531	128,247	123,450	142,352	246,060	2,506,060
Term Z4 St. 219	46,655	46,655	42,140	46,655	30,090	31,093	30,090	31,093	31,093	30,090	31,093	45,150	441,897
Term Z4 St. 313	95,015	156,767	120,680	60,977	120,000	116,157	87,000	80,693	75,888	61,050	59,737	50,730	1,084,694
Mo Dlvd Tetco Supply	775,000	775,000	700,000	620,000	600,000	310,000	225,000	155,000	155,000	225,000	310,000	600,000	5,450,000
Mo Dlvd Leidy	1,085,000	1,240,000	980,000	930,000	750,000	310,000	225,000	155,000	155,000	225,000	310,000	900,000	7,265,000
Mo Dlvd Z4 300L	310,000	310,000	280,000	310,000	300,000	310,000	300,000	310,000	310,000	300,000	310,000	300,000	3,650,000
Mo Dlvd Z4 300L (2)	62,000	62,000	56,000	62,000	60,000	0	0	0	0	0	0	60,000	362,000
Spot M2	1,204,625	3,243,729	1,225,347	1,153,627	1,349,455	629,396	64,669	99,473	96,850	297,496	1,344,541	2,119,042	12,828,250
Spot Leidy	260,791	702,240	265,277	249,750	292,146	136,259	14,000	21,535	20,967	64,405	291,082	458,755	2,777,207
Spot A06	446,157	1,201,381	453,832	427,269	499,798	233,110	23,952	36,842	35,870	110,184	497,978	784,830	4,751,203
Spot Z4 Marcellus	133,847	360,414	136,150	128,181	149,939	69,933	7,186	11,053	10,761	33,055	149,394	235,449	1,425,362
Spot Transco Gulf	0	0	0	0	0	0	0	0	0	0	0	0	0
Asset Management Refill	0	0	0	0	1,361,405	1,361,405	1,361,405	1,361,405	1,361,405	1,361,405	1,361,405	0	9,529,835
Withdrawn Volumes													
EGTS GSS	746,220	1,308,455	1,272,248	887,187	0	0	0	0	0	0	0	170,000	4,384,110
Tetco SS1	76,570	140,895	140,505	103,365	0	0	0	0	0	0	0	0	461,335
Transco GSS	385,175	854,422	826,940	702,485	0	0	0	0	0	0	0	0	2,769,022
Transco SS-2	919,460	940,695	866,620	612,975	0	0	0	0	0	0	0	0	3,339,750
Transco LSS	193,068	193,068	175,930	135,472	0	0	0	0	0	0	0	0	697,538
Transco ESS	0	0	41,643	37,751	0	0	0	0	0	0	0	0	79,394
Transco LGA	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI Storage Co. Service II	155,000	186,000	168,000	128,589	0	0	0	0	0	0	0	79,847	717,436
TCO FSS	1,768,800	1,867,850	1,436,325	904,327	0	0	0	0	0	0	0	0	5,977,302
Injected Volumes													
EGTS GSS	0	0	0	0	554,546	638,923	637,052	638,922	638,922	637,053	638,692	0	4,384,110
Tetco SS1	0	0	0	0	8,132	86,335	83,550	86,335	86,335	59,250	51,398	0	461,335
Transco GSS	0	0	0	0	217,440	472,688	458,250	452,665	421,011	407,430	339,538	0	2,769,022
Transco SS-2	0	0	0	0	317,720	509,144	492,720	509,144	509,144	492,720	509,158	0	3,339,750
Transco LSS	0	0	0	0	81,506	103,788	100,440	103,788	103,788	100,440	103,788	0	697,538
Transco ESS	0	0	0	0	11,130	11,501	11,130	11,501	11,501	11,130	11,501	0	79,394
Transco LGA	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI Storage Co. Service II	0	0	0	0	112,500	139,500	106,400	99,200	93,000	90,000	76,836	0	717,436
TCO FSS	0	0	0	0	720,905	876,066	876,066	876,066	876,066	876,066	876,067	0	5,977,302
Total Demand Served	9,806,832	14,597,527	10,180,209	8,457,663	4,755,434	2,281,563	1,110,374	1,088,878	1,085,914	1,499,576	3,458,956	7,236,115	65,559,041
Total Choice Bundled Demand	951,965	1,397,024	1,199,268	882,704	0	0	0	0	0	0	0	73,778	4,504,739

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED SUPPLY UNIT RATE IN \$/DTH
UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
COMMODITY**

	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	AVERAGE
Supply Rate													
Term M2	3.6087	4.0843	3.9719	3.4055	2.8933	2.7458	2.7825	2.8823	2.8647	2.5336	2.5055	2.9034	3.0985
Term Leidy	3.6524	4.0685	3.9006	3.4338	2.8379	2.6827	2.7445	2.9022	2.8620	2.4701	2.4319	2.9183	3.0754
Term A06	3.6680	4.1509	4.0368	3.4618	2.9418	2.7920	2.8292	2.9306	2.9127	2.5766	2.5481	2.9520	3.1500
Term Z4 Marcellus	3.6219	3.9172	3.7871	3.4611	2.8077	2.7077	2.7042	2.8569	2.8167	2.4652	2.3918	2.9534	3.0409
Term Z4 St. 219	3.8203	4.0829	3.9579	3.6394	3.2773	3.1296	3.0608	3.2110	3.2211	2.8368	2.7861	3.1241	3.3456
Term Z4 St. 313	3.5415	3.8390	3.7087	3.3780	3.0449	2.9580	3.0500	3.1846	3.1866	3.0002	2.9849	2.9551	3.2359
Mo Dlvd Tetco Supply	3.6087	4.0843	3.9719	3.4055	2.8933	2.7458	2.7825	2.8823	2.8647	2.5336	2.5055	2.9034	3.0985
Mo Dlvd Leidy	3.6524	4.0685	3.9006	3.4338	2.8379	2.6827	2.7445	2.9022	2.8620	2.4701	2.4319	2.9183	3.0754
Mo Dlvd Z4 300L	3.6219	3.9172	3.7871	3.4611	2.8077	2.7077	2.7042	2.8569	2.8167	2.4652	2.3918	2.9534	3.0409
Mo Dlvd Z4 300L (2)	3.6719	3.9672	3.8371	3.5111	2.8577	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.0034	1.7374
Spot M2	3.6087	4.0843	3.9719	3.4055	2.8933	2.7458	2.7825	2.8823	2.8647	2.5336	2.5055	2.9034	3.0985
Spot Leidy	3.6524	4.0685	3.9006	3.4338	2.8379	2.6827	2.7445	2.9022	2.8620	2.4701	2.4319	2.9183	3.0754
Spot A06	3.6680	4.1509	4.0368	3.4618	2.9418	2.7920	2.8292	2.9306	2.9127	2.5766	2.5481	2.9520	3.1500
Spot Z4 Marcellus	3.6219	3.9172	3.7871	3.4611	2.8077	2.7077	2.7042	2.8569	2.8167	2.4652	2.3918	2.9534	3.0409
Spot Transco Gulf	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Asset Management Refill	0.0000	0.0000	0.0000	0.0000	2.8691	2.8874	3.0491	3.2190	3.2546	3.1987	3.2363	0.0000	1.8095
Withdrawal Rate													
EGTS GSS	0.0272	0.0272	0.0272	0.0272	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0272	0.0113
Tetco SS1	0.0632	0.0632	0.0632	0.0632	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0211
Transco GSS	0.0731	0.0731	0.0731	0.0731	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0244
Transco SS-2	0.0395	0.0395	0.0395	0.0395	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0132
Transco LSS	0.0408	0.0408	0.0408	0.0408	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0136
Transco ESS	0.0000	0.0000	0.1075	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0179
Transco LGA	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Storage Co. Service II	0.0014	0.0014	0.0014	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0014	0.0006
TCO FSS	0.0333	0.0333	0.0333	0.0333	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0111
Injection Rate													
EGTS GSS	0.0000	0.0000	0.0000	0.0000	0.0402	0.0402	0.0402	0.0402	0.0402	0.0402	0.0402	0.0000	0.0235
Tetco SS1	0.0000	0.0000	0.0000	0.0000	0.0350	0.0350	0.0350	0.0350	0.0350	0.0350	0.0350	0.0000	0.0204
Transco GSS	0.0000	0.0000	0.0000	0.0000	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0820	0.0000	0.0478
Transco SS-2	0.0000	0.0000	0.0000	0.0000	0.0395	0.0395	0.0395	0.0395	0.0395	0.0395	0.0395	0.0000	0.0230
Transco LSS	0.0000	0.0000	0.0000	0.0000	0.0489	0.0489	0.0489	0.0489	0.0489	0.0489	0.0489	0.0000	0.0285
Transco ESS	0.0000	0.0000	0.0000	0.0000	0.1075	0.1075	0.1075	0.1075	0.1075	0.1075	0.1075	0.0000	0.0627
Transco LGA	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Storage Co. Service II	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
TCO FSS	0.0000	0.0000	0.0000	0.0000	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333	0.0000	0.0194
Total Com Vol	9,806,832	14,597,527	10,180,209	8,457,663	4,755,434	2,281,563	1,110,374	1,088,878	1,085,914	1,499,576	3,458,956	7,236,115	65,559,041
Total Com Cost	\$ 32,758,656	\$ 53,952,023	\$ 35,215,727	\$ 26,708,247	\$ 11,977,451	\$ 5,105,005	\$ 1,881,697	\$ 1,850,209	\$ 1,836,799	\$ 2,723,847	\$ 7,567,285	\$ 21,103,617	\$ 202,680,562
Com Unit Rate	\$ 3.34	\$ 3.70	\$ 3.46	\$ 3.16	\$ 2.52	\$ 2.24	\$ 1.69	\$ 1.70	\$ 1.69	\$ 1.82	\$ 2.19	\$ 2.92	\$ 3.09
Total Dem Cost	\$ 28,248,083	\$ 27,223,009	\$ 27,667,050	\$ 27,735,336	\$ 9,620,598	\$ 10,436,224	\$ 10,482,379	\$ 10,536,924	\$ 10,451,705	\$ 10,481,341	\$ 11,633,802	\$ 26,444,166	\$ 210,960,618
Dem Unit Rate	\$ 2.88	\$ 1.86	\$ 2.72	\$ 3.28	\$ 2.02	\$ 4.57	\$ 9.44	\$ 9.68	\$ 9.62	\$ 6.99	\$ 3.36	\$ 3.65	\$ 3.22
Total System Costs	\$ 61,006,739	\$ 81,175,031	\$ 62,882,777	\$ 54,443,583	\$ 21,598,049	\$ 15,541,229	\$ 12,364,076	\$ 12,387,133	\$ 12,288,504	\$ 13,205,188	\$ 19,201,087	\$ 47,547,783	\$ 413,641,179
System Unit Rate	\$ 6.22	\$ 5.56	\$ 6.18	\$ 6.44	\$ 4.54	\$ 6.81	\$ 11.14	\$ 11.38	\$ 11.32	\$ 8.81	\$ 5.55	\$ 6.57	\$ 6.31

UGI UTILITIES, INC. - GAS DIVISION
PROJECTED PURCHASE GAS COSTS IN (\$)
UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
COMMODITY

	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	TOTAL
Supply Cost													
Term M2	3,876,722	3,840,650	4,292,039	2,773,459	2,033,635	1,952,764	1,879,749	2,078,664	2,184,025	1,769,496	1,722,766	2,048,003	\$ 30,451,971
Term Leidy	1,778,652	2,768,761	1,847,310	1,788,668	807,362	1,794,735	1,778,500	1,897,728	1,803,127	1,506,012	1,382,203	1,281,290	\$ 20,434,348
Term A06	991,659	1,344,544	1,115,378	872,256	388,932	164,624	323,634	354,033	152,057	88,738	6,161	341,217	\$ 6,143,234
Term Z4 Marcellus	955,484	1,802,551	1,368,433	873,920	412,479	468,470	269,585	310,064	361,238	304,324	340,481	726,702	\$ 8,193,733
Term Z4 St. 219	178,234	190,489	166,785	169,798	98,614	97,310	92,101	99,840	100,152	85,360	86,628	141,054	\$ 1,506,367
Term Z4 St. 313	336,496	601,835	447,560	205,978	365,384	343,590	265,349	256,975	241,825	183,160	178,309	149,910	\$ 3,576,371
Mo Dlvd Tetco Supply	2,796,735	3,165,301	2,780,322	2,111,422	1,735,998	851,211	626,054	446,755	444,034	570,070	776,720	1,742,018	\$ 18,046,641
Mo Dlvd Leidy	3,962,876	5,044,889	3,822,624	3,193,480	2,128,447	831,627	617,506	449,848	443,617	555,779	753,901	2,626,491	\$ 24,431,085
Mo Dlvd Z4 300L	1,122,778	1,214,330	1,060,390	1,072,953	842,310	839,402	811,270	885,645	873,189	739,547	741,467	886,006	\$ 11,089,288
Mo Dlvd Z4 300L (2)	227,656	245,966	214,878	217,691	171,462	0	0	0	0	0	0	180,201	\$ 1,257,853
Spot M2	4,347,118	13,248,231	4,866,942	3,928,700	3,904,418	1,728,222	179,939	286,710	277,450	753,749	3,368,814	6,152,347	\$ 43,042,641
Spot Leidy	952,518	2,857,035	1,034,749	857,604	829,090	365,538	38,423	62,500	60,009	159,089	707,894	1,338,795	\$ 9,263,242
Spot A06	1,636,523	4,986,769	1,832,020	1,479,109	1,470,293	650,852	67,765	107,968	104,480	283,900	1,268,888	2,316,786	\$ 16,205,353
Spot Z4 Marcellus	484,776	1,411,811	515,615	443,652	420,984	189,361	19,433	31,578	30,311	81,486	357,325	695,364	\$ 4,681,694
Spot Transco Gulf	0	0	0	0	0	0	0	0	0	0	0	0	\$ -
Asset Management Refill	0	0	0	0	3,905,958	3,930,887	4,151,093	4,382,380	4,430,853	4,354,681	4,405,924	0	\$ 29,561,775
Withdrawal Cost													
EGTS GSS	20,297	35,590	34,605	24,131	0	0	0	0	0	0	0	4,624	\$ 119,248
Tetco SS1	4,839	8,905	8,880	6,533	0	0	0	0	0	0	0	0	\$ 29,156
Transco GSS	28,149	62,441	60,433	51,338	0	0	0	0	0	0	0	0	\$ 202,360
Transco SS-2	36,328	37,167	34,240	24,219	0	0	0	0	0	0	0	0	\$ 131,954
Transco LSS	7,883	7,883	7,183	5,531	0	0	0	0	0	0	0	0	\$ 28,480
Transco ESS	0	0	4,477	4,059	0	0	0	0	0	0	0	0	\$ 8,536
Transco LGA	0	0	0	0	0	0	0	0	0	0	0	0	\$ -
UGI Storage Co. Service II	217	260	235	180	0	0	0	0	0	0	0	112	\$ 1,004
TCO FSS	58,901	62,199	47,830	30,114	0	0	0	0	0	0	0	0	\$ 199,044
Injection Cost													
EGTS GSS	0	0	0	0	22,293	25,685	25,609	25,685	25,685	25,610	25,675	0	\$ 176,241
Tetco SS1	0	0	0	0	285	3,022	2,924	3,022	3,022	2,074	1,799	0	\$ 16,147
Transco GSS	0	0	0	0	17,832	38,765	37,581	37,123	34,527	33,413	27,846	0	\$ 227,087
Transco SS-2	0	0	0	0	12,553	20,116	19,467	20,116	20,116	19,467	20,117	0	\$ 131,954
Transco LSS	0	0	0	0	3,988	5,078	4,915	5,078	5,078	4,915	5,078	0	\$ 34,131
Transco ESS	0	0	0	0	1,197	1,237	1,197	1,237	1,237	1,197	1,237	0	\$ 8,536
Transco LGA	0	0	0	0	0	0	0	0	0	0	0	0	\$ -
UGI Storage Co. Service II	0	0	0	0	0	0	0	0	0	0	0	0	\$ -
TCO FSS	0	0	0	0	24,006	29,173	29,173	29,173	29,173	29,173	29,173	0	\$ 199,044
Subtotal Cost	\$ 23,804,839	\$ 42,937,606	\$ 25,562,928	\$ 20,134,795	\$ 19,597,518	\$ 14,331,669	\$ 11,241,268	\$ 11,772,122	\$ 11,625,206	\$ 11,551,238	\$ 16,208,407	\$ 20,630,922	\$ 229,398,518
Injected Value	\$ -	\$ -	\$ -	\$ -	\$ (7,620,067)	\$ (9,226,664)	\$ (9,359,571)	\$ (9,921,913)	\$ (9,788,407)	\$ (8,827,391)	\$ (8,641,122)	\$ -	\$ (63,385,135)
Withdrawal Value	\$ 10,911,243	\$ 14,107,497	\$ 12,623,266	\$ 8,945,191	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 709,205	\$ 47,296,402
Choice Bundled Sale Credit	\$ (3,051,720)	\$ (4,478,449)	\$ (3,844,501)	\$ (2,829,690)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (236,511)	\$ (14,440,871)
Net Financial Derivatives	\$ 1,094,294	\$ 1,385,369	\$ 874,034	\$ 457,951	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,811,648
Total Cost	\$ 32,758,656	\$ 53,952,023	\$ 35,215,727	\$ 26,708,247	\$ 11,977,451	\$ 5,105,005	\$ 1,881,697	\$ 1,850,209	\$ 1,836,799	\$ 2,723,847	\$ 7,567,285	\$ 21,103,617	\$ 202,680,562

UGI Utilities, Inc. - Gas Division
Computation of the Experienced Cost Factor: E
For the 2025 PGC Year

Effective December 1, 2025
Computation Year Ending November 30, 2026

SUPPLIER REFUND CREDITS

PGC

Prior	(Amortized Balance as of November 30, 2025)	Schedule C, Page 2	\$ (383,165)
Current	(Twelve Months Ended November 30, 2025)	Schedule C, Page 3	\$ 9,290,384
Interest	(Twelve Months Ended November 30, 2025)	Schedule C, Page 3	\$ 760,442

OVER / (UNDER) COLLECTION

Prior	(Amortized Balance as of November 30, 2025)	Schedule C, Page 4	\$ (8,962,831)
Current	(Twelve Months Ended November 30, 2025)	Schedule C, Page 6	\$ (15,920,372)
Interest	(Twelve Months Ended November 30, 2025)	Schedule C, Page 6	\$ (654,778)

TOTAL E **\$ (15,870,320)**

TOTAL S (Mcf) **63,465,008**

E/S Refund/(Collection) \$/Mcf **\$ (0.2501)**

UGI Utilities, Inc. - Gas Division
Prior Period Supplier Refund Balance (including interest)
To Be Included In the 2025 PGC Experienced Cost Factor

Month	Beginning Balance	Recovered / (Refunded)	Ending Balance
Balance as of November 30, 2024	\$ 6,554,862	\$ (1,060,125)	\$ 5,494,736
2024 Compliance Filing Balance 1/		\$ 779,901	\$ 6,274,637
December-24	\$ 6,274,637	\$ (1,903,323)	\$ 4,371,314
January-25	\$ 4,371,314	\$ (1,153,895)	\$ 3,217,419
February-25	\$ 3,217,419	\$ (1,026,896)	\$ 2,190,523
March-25	\$ 2,190,523	\$ (847,883)	\$ 1,342,640
April-25	est. \$ 1,342,640	\$ (482,605)	\$ 860,035
May-25	est. \$ 860,035	\$ (238,656)	\$ 621,379
June-25	est. \$ 621,379	\$ (117,521)	\$ 503,858
July-25	est. \$ 503,858	\$ (99,658)	\$ 404,200
August-25	est. \$ 404,200	\$ (85,314)	\$ 318,887
September-25	est. \$ 318,887	\$ (106,774)	\$ 212,112
October-25	est. \$ 212,112	\$ (197,440)	\$ 14,672
November-25	est. \$ 14,672	\$ (397,837)	\$ (383,165)

1/ See current supplier refund balance plus interest on Schedule C, Page 1 of the Compliance filing at Docket No. R-2024-3048828, filed November 27, 2024.

UGI Utilities, Inc. - Gas Division
List of Current Supplier Refunds
To Be Included In the 2025 PGC Experienced Cost Factor

<u>Supplier</u>	<u>Principal Amount</u>	<u>Date Rec'd</u>	<u>Rate %</u>	<u>Interest Weight</u>	<u>Interest Amount</u>
Texas Eastern	\$ 10,810	Nov-24	6%	19	\$ 1,027
Transco	\$ 66	Nov-24	6%	19	\$ 6
Tennessee	\$ 2,130	Nov-24	6%	19	\$ 202
Transco	\$ 11,645	Dec-24	6%	18	\$ 1,048
Texas Eastern	\$ 26,130	Dec-24	6%	18	\$ 2,352
Columbia Gas	\$ 4,211	Dec-24	6%	18	\$ 379
Texas Eastern	\$ 11,985	Jan-25	6%	17	\$ 1,019
Transco	\$ 439	Jan-25	6%	17	\$ 37
Unauthorized Overrun	\$ 1,567,425	Jan-25	6%	17	\$ 133,231
Unauthorized Overrun	\$ 216,712	Jan-25	6%	17	\$ 18,421
Unauthorized Overrun	\$ 1,875,343	Jan-25	6%	17	\$ 159,404
Texas Eastern	\$ 169,611	Feb-25	6%	16	\$ 13,569
Tennessee	\$ 13,152	Feb-25	6%	16	\$ 1,052
Transco	\$ 13,827	Feb-25	6%	16	\$ 1,106
Unauthorized Overrun	\$ 455,992	Feb-25	6%	16	\$ 36,479
Unauthorized Overrun	\$ 4,558,333	Feb-25	6%	16	\$ 364,667
Texas Eastern	\$ 192,891	Mar-25	6%	15	\$ 14,467
Unauthorized Overrun	\$ 159,683	Mar-25	6%	15	\$ 11,976
<u>Total</u>	<u>\$ 9,290,384</u>				<u>\$ 760,442</u>

UGI Utilities, Inc. - Gas Division
Prior Over / (Under) Collection Balance (including interest)
To Be Included In the 2025 PGC Experienced Cost Factor

Month	Beginning Balance	Recovered / (Refunded)	Ending Balance
Balance as of November 30, 2024	\$ 7,370,744	\$ (1,015,517)	\$ 6,355,227
2024 Compliance Filing Balance 1/		\$ (22,358,392)	\$ (16,003,165)
True-Up of November 2024 Estimate 2/		\$ (9,782,359)	\$ (25,785,524)
December-24	\$ (25,785,524)	\$ (578,534)	\$ (26,364,059)
January-25	\$ (26,364,059)	\$ 3,244,336	\$ (23,119,723)
February-25	\$ (23,119,723)	\$ 3,050,433	\$ (20,069,290)
March-25	\$ (20,069,290)	\$ 3,108,828	\$ (16,960,462)
April-25	est. \$ (16,960,462)	\$ 2,236,461	\$ (14,724,000)
May-25	est. \$ (14,724,000)	\$ 1,105,965	\$ (13,618,036)
June-25	est. \$ (13,618,036)	\$ 544,611	\$ (13,073,424)
July-25	est. \$ (13,073,424)	\$ 461,829	\$ (12,611,595)
August-25	est. \$ (12,611,595)	\$ 395,356	\$ (12,216,239)
September-25	est. \$ (12,216,239)	\$ 494,807	\$ (11,721,432)
October-25	est. \$ (11,721,432)	\$ 914,966	\$ (10,806,466)
November-25	est. \$ (10,806,466)	\$ 1,843,635	\$ (8,962,831)

1/ See current over/(under) collection balance plus interest on Schedule C, Page 1 of the 2024 Compliance filing at Docket No. R-2024-3048828, filed November 27, 2024.

2/ Incremental balance plus associated interest at 8.50%.

UGI Utilities, Inc. - Gas Division
Development of the Current Over/(Under) Collection
For the Period Ending November 30, 2025

	<u>Sales - Mcf</u>	<u>Base Rate</u>	<u>Revenue</u>	<u>Cost</u>	<u>(Under)/Over Collection</u>	<u>Interest Rate 1/</u>	<u>Interest Weight</u>	<u>Interest</u>
April-24	6,198,339	4.6876	\$ 29,055,547	\$ 14,144,551	\$ 14,910,996	8.50%	14	\$ 1,478,674
May-24	2,662,723	4.6913	\$ 12,491,557	\$ 10,886,297	\$ 1,605,260	8.50%	13	\$ 147,818
June-24	1,295,039	4.9177	\$ 6,368,563	\$ 10,189,839	\$ (3,821,275)	8.50%	12	\$ (324,808)
July-24	1,021,282	5.2532	\$ 5,364,947	\$ 12,792,920	\$ (7,427,974)	8.50%	11	\$ (578,763)
August-24	970,567	5.2354	\$ 5,081,309	\$ 10,722,665	\$ (5,641,357)	8.50%	10	\$ (399,596)
September-24	1,004,626	5.2311	\$ 5,255,309	\$ 9,381,720	\$ (4,126,412)	8.50%	9	\$ (263,059)
October-24	1,628,796	5.2312	\$ 8,520,626	\$ 14,141,881	\$ (5,621,256)	8.50%	8	\$ (318,538)
November-24	<u>2,940,852</u>	5.2318	<u>\$ 15,385,826</u>	<u>\$ 34,157,331</u>	<u>\$ (18,771,506)</u>	8.50%	7	<u>\$ (930,754)</u>
PGC Total	<u>17,722,223</u>		<u>\$ 87,523,683</u>	<u>\$ 116,417,206</u>	<u>\$ (28,893,523)</u>			<u>\$ (1,189,026)</u>

1/ The interest rate is the prime rate in effect April 2, 2024 per the Wall Street Journal.

UGI Utilities, Inc. - Gas Division
Development of the Current Over/(Under) Collection
For the Period Ending November 30, 2025

	<u>Sales - Mcf</u>	<u>Base Rate</u>	<u>Revenue</u>	<u>Cost</u>	<u>(Under)/Over Collection</u>	<u>Interest Rate 1/</u>	<u>Interest Weight</u>	<u>Interest</u>
December-24	8,080,926	5.3345	\$ 43,107,456	\$ 55,510,820	\$ (12,403,364)	7.50%	18	\$ (1,395,378)
January-25	12,985,358	5.4564	\$ 70,853,137	\$ 78,710,753	\$ (7,857,616)	7.50%	17	\$ (834,872)
February-25	11,926,128	5.4583	\$ 65,096,899	\$ 59,284,974	\$ 5,811,925	7.50%	16	\$ 581,192
March-25	9,840,795	5.8094	\$ 57,169,301	\$ 45,988,942	\$ 11,180,359	7.50%	15	\$ 1,048,159
April-25	est. 5,605,166	6.2932	\$ 35,274,432	\$ 20,090,698	\$ 15,183,734	7.50%	14	\$ 1,328,577
May-25	est. 2,771,841	6.2932	\$ 17,443,753	\$ 12,991,854	\$ 4,451,899	7.50%	13	\$ 361,717
June-25	est. 1,364,941	6.2932	\$ 8,589,845	\$ 11,256,713	\$ (2,666,868)	7.50%	12	\$ (200,015)
July-25	est. 1,157,466	6.2932	\$ 7,284,162	\$ 10,770,589	\$ (3,486,427)	7.50%	11	\$ (239,692)
August-25	est. 990,868	6.2932	\$ 6,235,730	\$ 10,560,777	\$ (4,325,047)	7.50%	10	\$ (270,315)
September-25	est. 1,240,118	6.2932	\$ 7,804,314	\$ 12,263,509	\$ (4,459,195)	7.50%	9	\$ (250,830)
October-25	est. 2,293,148	6.2932	\$ 14,431,241	\$ 18,314,165	\$ (3,882,924)	7.50%	8	\$ (194,146)
November-25	est. 4,620,639	6.2932	\$ 29,078,608	\$ 42,545,455	\$ (13,466,847)	7.50%	7	\$ (589,175)
<u>PGC Total</u>	<u>62,877,395</u>		<u>\$ 362,368,877</u>	<u>\$ 378,289,249</u>	<u>\$ (15,920,372)</u>			<u>\$ (654,778)</u>

1/ The interest rate is the prime rate in effect April 2, 2025 per the Wall Street Journal.

UGI UTILITIES, INC. - GAS DIVISION

GAS TARIFF

INCLUDING THE GAS SERVICE TARIFF NO. 7

AND

THE CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules
Governing the
Furnishing of
Gas Service and Choice Aggregation Service
in the
Territory Described Herein

Issued: May 30, 2025

Effective for service rendered on
and after December 1, 2025.

Issued By:

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

<https://www.ugi.com/tariffs>

NOTICE

This tariff makes increases and decreases to existing rates (see Page 2).

LIST OF CHANGES MADE BY THIS SUPPLEMENT
(Page Numbers Refer to Official Tariff)

Rider B - Purchased Gas Costs, Page 52

- The Annual C-Factor has increased.
- The Annual E-Factor has decreased.
- The Total Purchased Gas Cost rate has increased.

Section 15, Price to Compare, Page 57

- The Annual C-Factor has increased.
- The Annual E-Factor has decreased.
- The Merchant Function Charge has increased.
- The Price to Compare Charge has increased.

Cover Page, UGI Utilities, Inc. - Gas Division - Gas Choice Supplier Tariff

- Issuance and effective dates updated.

Section 7.3, - Nomination Procedure, Page 118

- Peak Day allocation percentages updated.

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

The amount retained by the Company will be an incentive to pursue additional sales and will be treated below the line for ratemaking purposes. For purposes of calculating this margin, the cost of gas will be equal to the monthly average commodity cost of gas plus variable transportation costs to deliver the gas to the off-system customer. The monthly average commodity cost of gas shall be defined as the monthly average commodity cost of gas purchases for all supplies scheduled at the beginning of the month; provided, however, that if an additional unscheduled purchase is made during the month specifically for an off-system sale, such purchase shall be considered to be the gas used to make the off-system sale and the commodity cost of such purchase will be assigned to off-system sales up to the volume of the purchase.

Filing with the PUC: Audit, Rectification

The Company's annual reconciliation statement shall be submitted to the Commission by May 1 of each year, or such other time as the PUC may prescribe.

Quarterly Adjustments

When making the December 1, March 1, June 1 and September 1 quarterly C-factor adjustments, the Company will refund or recover all actual and projected incremental over or under collections from December 1 through November 30 over either remaining PGC year sales volumes or annual PGC year sales volumes, however the March 1 adjustment for projected over or under collections shall only utilize the remaining PGC year sales volumes. Any quarterly PGC rate change on December 1, March 1 and June 1 will be capped at 25% of the then-current PGC rate, with any amounts above this cap being brought forward for inclusion in the calculation of subsequent quarterly C-factor adjustments. Any quarterly PGC rate change on September 1 will be capped at 15% of the then-current PGC rate, with any amounts above this cap being brought forward for inclusion in the calculation of subsequent quarterly C-factor adjustments. The Company is authorized, at its sole discretion, to waive the quarterly cap on rate decreases only.

Rider B - Purchased Gas Cost (Mcf)

Annual C-Factor	\$ 6.5176	(I)
Annual E-Factor	\$ 0.2501	(D)
Total Purchased Gas Cost	<u>\$ 6.7677</u>	(I)

(D) Indicates Decrease
 (I) Indicates Increase

RULES AND REGULATIONS

15. PRICE TO COMPARE

The Price to Compare ("PTC") is composed of the Annual C-Factor, Annual E-Factor, Gas Procurement Charge and Merchant Function Charge. The PTC rate will change whenever any components of the PTC change. The current PTC rate is detailed below:

Price to Compare

	Rate R (CCF)	Rate N (MCF)	
Annual C-Factor	\$ 0.65176	\$ 6.5176	(I)
Annual E-Factor	\$ 0.02501	\$ 0.2501	(D)
Gas Procurement Charge	\$ 0.00660	\$ 0.0660	
Merchant Function Charge	<u>\$ 0.01536</u>	<u>\$ 0.0298</u>	(I)
Total Price to Compare	<u>\$ 0.69873</u>	<u>\$ 6.8635</u>	(I)

(D) Indicated Decrease
 (I) Indicates Increase

UGI UTILITIES, INC. - GAS DIVISION
GAS CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules
Governing the
Furnishing of
Gas Aggregation Service

Issued: May 30, 2025

Effective for service rendered on and
after December 1, 2025.

Issued By:

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

<https://www.ugi.com/tariffs>

NOTICE

This supplement makes changes to existing rates (see page 2).

RULES AND REGULATIONS

7. NOMINATION PROCEDURE

- 7.1 Customer Choice Nomination Procedure. The Nomination Procedure specifies requirements for nominating, scheduling, balancing, and communicating information relating to Choice Supplier's gas deliveries for customers served under Rates RT and NT.
- 7.2 Contact Persons. A list of Company contact persons will be posted on the Company's Web Site, located at https://ugi.outsystemsenterprise.com/UGIContacts_FO/, or its successor, along with their department affiliation, email address, and telephone number.
- 7.3 Mandatory Assignment. As used in this tariff the term "Firm Commodity Supply Alternative" shall mean a Company purchase of natural gas, delivered directly to its distribution system or at points along Company pipeline capacity routes (Commodity Delivery Points), constituting a component of Company's PGC supply portfolio and an alternative to pipeline capacity contracts upstream of the Commodity Delivery Points or other firm sources of PGC supply. Firm Commodity Supply Alternative contractual arrangements may require the payment of demand charges or minimum take requirements. Except as provided below, Choice Supplier shall be required to accept releases of Company pipeline capacity combined with bundled city gate sales and, as applicable, peaking sales of gas from Company and sales of gas associated with Firm Commodity Supply Alternative arrangements, in accordance with the following assignments:

A monthly release of interstate pipeline capacity or allocation of Firm Commodity Supply Alternative in an amount equal to thirty-eight percent (38%) of the Peak (C) Day Delivery Requirement ("PDDR") of the Choice Customers served by the Choice Supplier during the month shall be released or allocated at a price equal to the projected weighted average demand cost of all PGC capacity, storage, peaking and Firm Commodity Supply Alternative assets, divided by 0.255. Effective November 1, (C) 2020, to the extent the full Firm Commodity Supply Alternative is not fully nominated by Choice Supplier to satisfy its DDR, the remaining daily quantity may be nominated to a non-Choice transportation customer or pool of non-Choice transportation customers.

The Company shall also provide Choice Suppliers with a must-take Monthly Bundled Sale Quantity ("MBSQ") during each winter month of November through March, and the Choice Supplier would be permitted to nominate and purchase gas at the Company's city gates throughout each winter month, subject to the Maximum Daily Quantity ("MDQ") limits, up to the MBSQ. The MDQ equals twenty-four percent (C) (24%) of the PDDR of the Choice Customers served by the Choice Supplier during the month multiplied by the percentage shown on the Company's Energy Management website. The minimum daily quantity is zero. Choice Suppliers are required to nominate to the Company a daily quantity for bundled sales no later than 2:00 P.M. Eastern Prevailing Time on each Intercontinental Exchange ("ICE") trading day for deliveries applicable to the ICE flow dates. If no nomination is received, the nomination quantity would default to zero. The Company reserves the right to issue Operational Flow Orders ("OFO") that can modify the daily bundled sale MDQ or require certain levels of deliveries from the released firm transportation contracts. These OFOs would be issued for operational reasons only. MBSQs would be based on the Company's storage withdrawal plan, to be updated annually, and communicated as a percentage of each Choice Supplier's pre-month normalized

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC
UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

:
:
:
:
:
:

Docket No. R-2025-3054938

DIRECT TESTIMONY

OF

KIMBERLY M. BASSININSKY

UGI GAS STATEMENT NO. 1

Date: May 30, 2025

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Kimberly M. Bassininsky, and my business address is UGI Utilities, Inc., 1 UGI
4 Drive, Denver, PA 17517.

5

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

7 A. I am employed by UGI Utilities, Inc. (“UGI”) as a Principal Analyst – Rates. UGI is a wholly-
8 owned subsidiary of UGI Corporation (“UGI Corp.”). UGI has two operating divisions, the
9 Electric Division (“UGI Electric”) and the Gas Division (“UGI Gas” or the “Company”), each
10 of which is a public utility regulated by the Pennsylvania Public Utility Commission
11 (“Commission” or “PUC”).

12

13 **Q. What is your educational background?**

14 A. Please see my resume, which is attached as UGI Gas Exhibit KMB-1.

15

16 **Q. Please describe your professional experience.**

17 A. Please see my resume, which is attached as UGI Gas Exhibit KMB-1.

18

19 **Q. Have you testified previously before this Commission?**

20 A. Yes. UGI Gas Exhibit KMB-1 identifies the proceedings in which I provided testimony.

21

22 **Q. What are your responsibilities in your current role with UGI?**

23 A. I am significantly involved and/or primarily responsible for various tariff filings and related
24 computations for UGI Gas and UGI Electric rate and regulatory filings before federal and

1 state regulatory agencies. Before the Commission, these matters include Annual 1307(f)
2 Purchased Gas Cost (“PGC”), Generation Supply Rate, Energy Efficiency and Conservation
3 Rider, Universal Service Program Rider, State Tax Adjustment Surcharge, and Distribution
4 System Improvement Charge, and Weather Normalization Adjustment filings. In addition, I
5 have assisted in the development of certain supporting schedules in the various base rate case
6 proceedings listed on UGI Gas Exhibit KMB-1. Finally, I am currently responsible for the
7 development and preparation of the Purchased Gas Adjustment (“PGA”) and Actual Cost
8 Adjustment surcharge filings for UGI Gas’s Maryland division.

9
10 **Purpose of Testimony**

11 **Q. What is the purpose of your testimony?**

12 A. My testimony will address certain components of UGI Gas’s 2025 1307(f) filing and will
13 explain and support the development and computation of UGI Gas’s PGC rates proposed to
14 be effective on December 1, 2025. In addition, I will discuss UGI Gas’s Revenue Sharing
15 Incentive Mechanism (“RSIM”), and retainage rate (as defined herein).

16
17 **Q. Which portions of the Company’s 2025 1307(f) filing are you sponsoring?**

18 A. As shown in the Table of Contents and Witness Index list for UGI Gas Book 2 (filed on May
19 30, 2025), I am sponsoring the following:

- 20 • Schedule A (summary of PGC computation for the 12 months ending November
21 30, 2026);
- 22 • Schedule B – Page 1 (projected sales and costs (*i.e.*, computation of C-factor) for
23 the 12 months ending November 30, 2026);

- 1 • Schedule C (computation of E-factor for the 12 months ending November 30,
2 2026); and
- 3 • The *pro forma* Supplements to Gas Tariff – Pa. P.U.C. No. 7 and 7S, which have
4 been submitted in accordance with Section 53.64(a) of the Commission’s
5 regulations at 52 Pa. Code § 53.64(a).

6 Additionally, I am sponsoring the following sections of the preliminary supporting
7 information (“Book 1”) filed on May 1, 2025, in this proceeding in accordance with 52 Pa.
8 Code § 53.64(c): Sections 8, 10, 12, and related attachments, in addition to page 1 of
9 Attachment 4-1 in Section 4.

10

11 **II. PGC RATE PROPOSAL SUMMARY**

12 **Q. Please describe the Company’s PGC rate proposal in this proceeding.**

13 A. UGI Gas is proposing a PGC rate of \$6.7677 per Mcf, effective December 1, 2025.

14

15 **Q. How does this proposed PGC rate compare to the current PGC rate?**

16 A. The current PGC rate of \$6.6061 per Mcf became effective March 1, 2025, and is unchanged
17 for June 1, 2025. The calculated PGC rate of \$6.7677 per Mcf for December 1, 2025, is an
18 increase of \$0.1616 per Mcf, or 2.4%, from the current PGC rate. The December 1, 2025
19 increase in the PGC rate is largely attributable to an increase in the forecasted cost of supply,
20 as described in UGI Gas Statement No. 2, the Direct Testimony of Jesse R. Tyahla.

21

1 **III. DEVELOPMENT OF THE PGC RATES**

2 **Q. Please summarize the major components that comprise the PGC rate formula.**

3 A. The basic PGC rate formula is $(C-E)/S$, where the “C-factor,” or the Projected Cost of Gas
4 component, represents the projected cost of gas for the rate computation period beginning
5 December 1, 2025, through November 30, 2026; the “E-factor,” or the Experienced Cost
6 Factor, represents the experienced over/(under) collections due to variations between
7 projected gas costs and actual gas costs as well as the variances between projected gas sales
8 and actual gas sales; and the “S,” or the Projected Sales component, represents the projected
9 Mcf of gas to be billed to customers during the effective computation period. UGI Gas’s PGC
10 rate consists of the Projected Cost of Gas per Mcf (C/S) and the Experienced Cost per Mcf ($-$
11 E/S) (*e.g.*, the Gas Cost Adjustment Charge).

12
13 **Q. Please summarize the PGC rate computation supporting the schedules you prepared in**
14 **this filing.**

15 A. Schedules A, B, and C provide the detailed computation of the proposed December 1, 2025
16 PGC rates. In particular:

- 17 • Schedule A is the PGC computation schedule showing, at a summary level, the
18 computation of the PGC rate for Rate Schedules R – Residential Service, N – Non-
19 Residential Service and GL – Gas Lighting Service.
- 20 • Schedule B, Page 1, provides the development of the Projected Cost of Gas, or C-
21 factor, and Projected Sales for the computation period of December 1, 2025, through
22 November 30, 2026.
- 23 • Schedule B, Pages 2 through 13, provides the forecasted PGC supply portfolio by
24 month.

- 1 • Schedule C, Page 1, provides the computation of the Experienced Cost Factor, or E-
- 2 factor, which consists of the current and prior Supplier Refunds and current and prior
- 3 period over/(under) collections, including interest.
- 4 • Schedule C, Page 2, provides the remaining ending balance of the “prior” Supplier
- 5 Refunds previously reflected in last year’s 1307(f) proceeding. The ending balance is
- 6 included in the E-factor computation shown on Schedule C, Page 1.
- 7 • Schedule C, Page 3, provides a list of “current” Supplier Refunds, representing
- 8 Supplier Refunds that were received by the Company from November 2024 – March
- 9 2025. Additionally, any refunds not recorded in prior PGC filings are included. Both
- 10 the current Supplier Refunds and interest amounts are included in the E-factor
- 11 computation shown on Schedule C, Page 1.
- 12 • Schedule C, Page 4, provides the development of the prior under/over collection
- 13 balance, which is included in the E-factor computation shown on Schedule C, Page 1.
- 14 • Schedule C, Page 5, provides the monthly and total under/over collections and interest
- 15 computation for the Historic Period of April 1, 2024, through November 30, 2024.
- 16 • Schedule C, Page 6, provides the projected under/over collections and interest
- 17 computation on a month-by-month basis for the current PGC computation period of
- 18 December 1, 2024, through November 30, 2025. The under/over collections and
- 19 interest shown for this period are included in the E-factor computation shown on
- 20 Schedule C, Page 1.

21

1 **Q. Please summarize the computation of the calculated PGC rate for the 12 months**
2 **beginning December 1, 2025.**

3 A. As shown on Schedule A, the calculated PGC rate of \$6.7677 per Mcf is equal to the Projected
4 Cost of Gas per Mcf (C/S), \$6.5176, plus the Experienced Cost of Gas per Mcf (-E/S),
5 \$0.2501. The Projected Cost of Gas, or “C-factor,” of approximately \$413.6 million is divided
6 by Projected Sales (S) of approximately 63.5 Bcf, resulting in the Projected Cost per Mcf
7 (C/S) of \$6.5176. The Experienced Cost Factor, or “E-factor,” of (\$15.9) million under
8 collection is divided by Projected Sales, resulting in the Experienced Cost per Mcf (-E/S)
9 value of \$0.2501.

10

11 **Q. Please explain the development of the total C-Factor.**

12 A. The Projected Cost of Gas is shown on a month-by-month basis and in total for the 12-month
13 period December 1, 2025, through November 30, 2026, on Schedule B, Page 1. Projected
14 Capacity Release Credits, Off-System Sales Credits, Exchange Credits, Asset Management
15 Fee Credits, and Administrative Costs are all included in the C-factor computation. Schedule
16 B, Pages 2 through 13, detail these projected costs by month.

17

18 **Q. Please explain the development of the Projected Sales or “S” amount.**

19 A. On an annual basis, UGI Gas projects sales volumes for the upcoming PGC computation
20 periods. The PGC sales forecast ending November 30, 2026, was used to estimate the monthly
21 demand volumes provided in Attachments 1-B-1 and 1-B-2 of the Book 1 supporting
22 information filed on May 1, 2025, in this docket. In general, the process to forecast PGC sales
23 considers various factors, including trending and regression analysis, customer growth,
24 normal weather conditions, and levels of Customer Choice volumes. Schedule B, Page 1,

1 shows the Projected Sales, or “S” amount, for the period beginning December 1, 2025, through
2 November 30, 2026. Those sales projections form the basis for UGI Gas’s forecasted PGC
3 supply portfolio by month, and the resulting supply mix as shown on Schedule B, Pages 2
4 through 13. UGI Gas used a similar methodology to project sales volumes for the interim
5 period of April 1, 2025, through November 30, 2025. Projected sales for this period are
6 detailed monthly on Schedule C, Page 6, and are utilized to determine the annual E-Factor.

7
8 **Q. How have Customer Choice volumes been reflected in the Projected Sales amount?**

9 A. Estimated Customer Choice volumes of 22.1 Bcf have been excluded from PGC retail sales
10 in developing the Projected Sales for the December 1, 2025 – November 30, 2026 period.
11 Thus, the Projected Sales amount of 63.5 Bcf is net of the excluded Customer Choice volumes.

12
13 **Q. Please explain the development of the E-factor.**

14 A. The E-factor computation consists of two basic components: Supplier Refunds and over/under
15 collections. Interest is included in both components.

16
17 **Q. Please explain the Supplier Refunds included in the E-factor computation.**

18 A. The Supplier Refunds and over/under collection amounts are further classified as “prior” or
19 “current.” “Prior” refers to the remaining balances of amounts for refund/recovery from the
20 prior year’s 1307(f) proceeding that have not been fully refunded to or recovered from PGC
21 customers due to variations in sales volumes. “Current” refers to the amounts for
22 refund/recovery that were not previously incorporated in the prior year’s PGC rate
23 components and will be reflected for the first time in the current 1307(f) proceeding.

24

1 **Q. What is the Supplier Refund amount included in the E-factor computation?**

2 A. The prior Supplier Refund Balance of (\$383,165) reflects the ending balance projected as of
3 November 30, 2025. This balance is detailed in Schedule C, Page 2, and is included in the E-
4 factor computation on Schedule C, Page 1. As shown on Schedule C, Page 1, the current
5 Supplier Refund total is \$9,290,384. As shown on Schedule C, Page 3, the interest on the
6 current Supplier Refunds will be returned at the rate of six percent (6%). The related total
7 interest amount of \$760,442 is included in the E-factor computation on Schedule C, Page 1.

8
9 **Q. Please explain the over/under collection amount included in the E-Factor.**

10 A. Schedule C, Page 1, provides the development of the prior and current over/under collection
11 amounts plus interest projected as of November 30, 2025. The current under collection of
12 (\$15,920,372) and the associated interest of (\$654,778) is detailed at Schedule C, Page 6. The
13 prior period under collection amount of (\$8,962,831) is shown on Schedule C, Page 1, and
14 detailed on Schedule C, Page 4. This amount is presently charged to the PGC customer class
15 through the operation of the E-Factor.

16
17 **Q. Please explain how the applicable interest rate is determined to compute the total
18 interest expense related to the over/under collection amount in the E-factor.**

19 A. UGI Gas's current tariff allows for the refunding of interest on over collections and recovery
20 of interest on under collections consistent with the provisions of 66 Pa. C.S. § 1307(f)(5).
21 Additionally, in UGI Gas's 2019 Joint Petition for Settlement of Section 1307(f) Rate
22 Investigation at Docket Nos. R-2019-3009647, et al. ("2019 PGC Settlement"), which was
23 approved by Commission Order entered on October 24, 2019, it was agreed that:

24 On a going forward basis, beginning with the filing of its
25 proposed tariff on or before June 1, 2020 in its next annual

1 PGC filing, UGI Gas will use the prime rate in effect 60 days
2 prior (April 2) to the annual PGC filing date (June 1). The
3 60-day prime rate will be applied to the over/undercollection
4 balances for the PGC period December 1 of the prior year
5 through November 30 of the PGC year.¹
6

7 Consistent with this provision, for the PGC computation period, UGI Gas is recovering
8 interest at the prime rate for commercial borrowing as reported in The Wall Street Journal,
9 which is 7.50%, effective April 2, 2025.² The total amount of monthly interest expense is
10 then calculated on Schedule C, Page 6, and carried into the E-factor computation on Schedule
11 C, Page 1. Additionally, as shown on Schedule C, Page 5, for the Historic Period, UGI Gas
12 was recovering interest at the prime rate for commercial borrowing as reported in the Wall
13 Street Journal, which was 8.50%, effective April 2, 2024.³
14

15 **Q. Please summarize the development of the total interest expense included in the E-factor**
16 **for UGI Gas.**

17 A. As shown on Schedule C, Page 5, the Company computed the monthly interest amounts in the
18 Historic Period utilizing an interest rate of 8.50%. As shown on Schedule C, Page 6, the
19 Company computed the monthly interest amounts in the current PGC computation period
20 utilizing an interest rate of 7.50%. The total amount of monthly interest expense calculated
21 over the current PGC computation period, December 2024 through November 2025, is shown

¹ See PAPUC v. UGI Gas, Docket No. R-2019-3009647 (Order entered October 24, 2019).

² UGI Gas notes that the 2019 PGC Settlement language used 60 days and April 2, interchangeably, as the relevant date for determining the prime rate, based on the June 1 filing date for the Company's PGC. However, in 2025 the Company filed Book 2 on May 30, 2025, due to June 1, 2025, falling on a Sunday. UGI Gas continued to use the prime rate in effect on April 2, 2025, instead of March 31, 2025. The Company notes that there was no difference between the prime rate used in its Book 2 filing and the prime rate effective on March 31 (i.e., the rate in effect 60 days before the filing).

³ The interest expense from the months April 2024 through November 2024 were already included in the November 27, 2024 compliance filing using the interest rate from the prior year's 1307(f) filing at Docket No. R-2024-3048828.

1 on Schedule C, Page 6, in the amount of (\$654,778), which is included in the E-factor
2 computation shown on Schedule C, Page 1.

3
4 **Q. Please explain the development of the Total Sales used to calculate the Experienced Cost
5 of Gas per Mcf (-E/S).**

6 A. The projected sales used to calculate the Experienced Cost of Gas per Mcf were determined
7 using the Projected Sales as described above and shown on Schedule A, Page 1.

8
9 **IV. REVENUE SHARING MECHANISM**

10 **Q. Please describe the current RSIM for UGI Gas.**

11 A. Net margins derived from natural gas off-system sales, exchanges, and capacity releases
12 (excluding Choice and operational releases) are allocated 75% to the PGC customers and 25%
13 to the Company, with the 25% being treated below-the-line for ratemaking purposes. The
14 current RSIM went into effect on December 1, 2012, and is in effect through November 30,
15 2026, pursuant to the Commission Order entered in Docket No. R-2021-3025652 (Order
16 entered October 7, 2021).

17
18 **V. RETAINAGE RATES**

19 **Q. Does the Company retain a percentage of gas delivered on behalf of transportation
20 service customers to reflect lost and unaccounted for (“LAUF”) and company use gas
21 (collectively, the “retainage rate”)?**

1 A. Yes, it does. In the Company’s 2009 PGC proceedings,⁴ the Commission approved the use
2 of a retainage rate, calculated as follows:

3 [C]alculate the retainage rate for applicable transportation rate schedules as of
4 December 1 each year by using a three-year rolling average of actual lost and
5 unaccounted for gas (“LAUF”) and company use gas through September 30th
6 of each year.

7

8 **Q. Has UGI Gas complied with the 2009 settlement language?**

9 A. Yes. Consistent with the settlement terms, UGI Gas updates its retainage rate each year based
10 on a three-year rolling average of LAUF and company use gas for the three prior years ending
11 September 30. Effective December 1, 2024, the retainage rate for all customers was calculated
12 based on the three-year period ending September 30, 2024. Currently, this rate is 1.3% and
13 will be in effect until December 1, 2025.

14

15 **Q. Was UGI Gas’s method of computing its retainage rate adjusted as part of a
16 Commission-approved settlement in its 2010 PGC proceedings?**

17 A. Yes. In the 2010 PGC settlements,⁵ the Company agreed to “exclude volumes associated with
18 service to its Rate XD transportation customers receiving retainage discounts in calculating
19 its retainage rate in its compliance filing” and to “provide a schedule in its compliance filing
20 showing how it calculated its retainage rate using a three-year rolling average.” Consistent
21 with the terms of the 2010 PGC settlements, UGI Gas excluded volumes associated with
22 service to Rate XD customers receiving retainage discounts in calculating its retainage rate

⁴ See *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2009-2105911 (Order entered December 23, 2009) (Former South Rate District); *Pa. PUC v. UGI Penn Natural Gas, Inc.*, Docket No. R-2009-2105904 (Order entered October 8, 2009) (Former North Rate District); and *Pa. PUC v. UGI Central Penn Gas, Inc.*, Docket No. R-2009-2105909 (Order entered October 15, 2009) (Former Central Rate District).

⁵ See *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2010-2172933 (Order entered November 23, 2010) and *Pa. PUC v. UGI Penn Natural Gas, Inc.*, Docket No. R-2010-2172928 (Order entered November 23, 2010).

1 and will provide a schedule showing its retainage rate computation with its compliance filing
2 in this proceeding.

3
4 **Q. Please describe the Commission’s regulations at 52 Pa. Code § 59.111 addressing LAUF**
5 **or Unaccounted for Gas (“UFG”) reporting requirements and standards.**

6 A. 52 Pa. Code § 59.111 became effective in August of 2013. This regulation adopts a uniform
7 definition of UFG, requires natural gas distribution companies (“NGDCs”) to file annual
8 reports on or before September 30 documenting UFG levels for the 12 months ending August
9 31, and establishes UFG standards, which NGDCs address in annual PGC proceedings. UGI
10 will file its next annual UFG report on or before September 30, 2025.⁶

11
12 **Q. Does this conclude your direct testimony?**

13 A. Yes, it does.

⁶ See Settlements in *Pa. PUC v. UGI Central Penn Gas, Inc.*, Docket No. R-2015-2480937 (Order entered October 22, 2015) (former Central Rate District); *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2015-2480950 (Order entered October 22, 2015) (former South Rate District); and *Pa. PUC v. UGI Penn Natural Gas*, Docket No. R-2015-2480934 (Order entered October 22, 2015) (former North Rate District).

UGI GAS EXHIBIT KMB-1

(Resume and Educational Background)

Kimberly M. Bassininsky
Principal Analyst Rates

Work Experience

UGI Utilities, Inc., Denver, PA

2020 – Present	Rates Analyst - Senior/Principal (Progressive Positions)
2019 – 2020	Manager Financial Planning & Analysis
2018 – 2019	Principal Financial Planning & Analysis Leader
2017 – 2018	Senior Supervisor Financial Planning & Analysis
2016 – 2017	Senior Supervisor Operations Analysis
2015 – 2016	Senior Analyst Operations Analysis

Rentokil North America, Reading, PA

2013 – 2015	Finance Business Partner – Sales & Marketing
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Garden Fresh Restaurant Corp., San Diego, CA

1999 – 2013	Financial Analyst - I/II/Senior (Progressive Positions)
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Education

MBA, Alvernia University, Reading, PA

BS, Business Administration (Finance), San Diego State University, San Diego, CA

Previous Testimony

UGI Electric Phase IV EE&C Plan Petition	Docket No. M-2023-3043230
2024 UGI 1307(f) Proceeding	Docket No. R-2024-3048828
2023 UGI 1307(f) Proceeding	Docket No. R-2023-3040290
2022 UGI 1307(f) Proceeding	Docket No. R-2022-3032242
2021 UGI 1307(f) Proceeding	Docket No. R-2021-3025652
2024 UGI Commodity and Purchased Gas Proceeding	MD PSC Case No. 9516(g)
2023 UGI Commodity and Purchased Gas Proceeding	MD PSC Case No. 9516(f)
2022 UGI Commodity and Purchased Gas Proceeding	MD PSC Case No. 9516(e)
2021 UGI Commodity and Purchased Gas Proceeding	MD PSC Case No. 9516(d)

Assisted in Preparing

2025 UGI Gas Base Rate Case	Docket No. R-2024-3052716
2023 UGI Electric Base Rate Case	Docket No. R-2022-3037368
2022 UGI Gas Base Rate Case	Docket No. R-2021-3030218
2021 UGI Electric Base Rate Case	Docket No. R-2021-3023618
2020 UGI Gas Base Rate Case	Docket No. R-2019-3015162
2019 UGI Gas Base Rate Case	Docket No. R-2018-3006814
2017 UGI Gas Base Rate Case (the former North Rate District)	Docket No. R-2016-2580030

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC :
UTILITY COMMISSION :
 : Docket No. R-2025-3054938
v. :
 :
UGI UTILITIES, INC. – GAS DIVISION :

DIRECT TESTIMONY
OF
JESSE R. TYAHLA

UGI GAS STATEMENT NO. 2

Dated: May 30, 2025

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1 **I. Introduction**

2 **Q. Please state your name and address.**

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

5
6 **Q. By whom are you employed, and in what capacity?**

7 A. I was formerly employed by UGI Utilities Inc. (“UGI”) as Director – Energy Supply and
8 Planning. UGI is a wholly owned subsidiary of UGI Corporation (“UGI Corp.”). UGI has
9 two operating divisions, the Electric Division (“UGI Electric”) and the Gas Division (“UGI
10 Gas” or the “Company”), each of which is a public utility regulated by the Pennsylvania
11 Public Utility Commission (“Commission” or “PUC”). My current role is Director – FP&A
12 and Strategic Modeling for UGI Corporation.

13
14 **Q. Please briefly describe your responsibilities in your current capacity.**

15 A. As Director – Energy Supply and Planning, I was responsible for natural gas and electric
16 supply planning, procurement, and scheduling for UGI Electric and UGI Gas. Additionally,
17 I am responsible for the development and administration of delivery requirements for
18 licensed natural gas suppliers (“NGSs”) who serve pools of Choice Customers on UGI
19 Gas’s system (that elect to procure natural gas supply services from Choice NGSs).

20
21 **Q. What is your educational background?**

22 A. Please see my resume, which is attached as UGI Gas Exhibit JRT-1.

23

1 **Q. Were portions of the information filed by UGI Gas in this proceeding prepared by**
2 **you or persons under your direct supervision and control?**

3 A. Yes. I supervised the preparation of portions of the Company’s Preliminary Information
4 filed on May 1, 2025 (hereinafter referred to as “Book 1”), including supporting
5 information shown in the Table of Contents and Witness Index. Additionally, in this May
6 30, 2025 Purchased Gas Cost (“PGC”) filing (hereinafter referred to as “Book 2”), I am
7 sponsoring Pages 2 through 13 of Schedule B (development of projected purchased gas
8 cost).

9
10 **Q. What is the purpose of your testimony?**

11 A. The purpose of my testimony is to supply the information specified in 66 Pa. C.S. § 1317(a)
12 in order to demonstrate that UGI Gas is pursuing a least cost fuel procurement policy,
13 consistent with its obligation to provide safe, adequate and reliable service to its customers
14 so that the Commission may determine that the Company’s rates are just and reasonable
15 pursuant to 66 Pa. C.S. § 1318.

16
17 **Q. What topics will you address in your direct testimony?**

18 A. My testimony addresses: (1) historic and projected gas purchases; (2) UGI Gas’s
19 procurement policy and peak day demand; (3) Choice program update; (4) recent contract
20 renewals; (5) supply request for proposals (“RFPs”); (6) the Company’s participation in
21 the Federal Energy Regulatory Commission (“FERC”) proceedings; (7) Renewable
22 Natural Gas (“RNG”) pilot program update; (8) UGI Gas’s hedging pilot program update;
23 (9) hourly flow restrictions; and (10) capacity planning and supplier warranties.

1 **Q. Are you sponsoring any exhibits?**

2 A. Yes. I am sponsoring the following Sections in Book 1, which correspond to the required
3 information specified in Section 1317:

- 4 • Sections 1-3.
- 5 • Page 2 of Attachment 4-1 in Section 4.
- 6 • Sections 5, 6, 7, 9, 11, 13 and 14.

7 Also, I am sponsoring the exhibits identified as UGI Gas Exhibits JRT-1 through JRT-5.

8
9 **II. Historic and Projected Gas Purchases**

10 **Q. Please generally describe the information contained in Book 1, which was filed on**
11 **May 1, 2025.**

12 A. Book 1 contains information related to the Company's PGC that is required to be filed
13 pursuant to Section 1317(a) of the Pennsylvania Public Utility Code. The information is
14 necessary for the Commission to make specific findings that UGI Gas is pursuing a least
15 cost fuel procurement policy, consistent with its obligation to provide safe, adequate, and
16 reliable service to its customers. The fourteen sections in Book 1 provide data related to
17 the Company's sources of gas supply, supply/demand projections, fuel procurement
18 practices, peak day methodology, reliability plans, and PGC costs.

19
20 **Q. Please describe the PGC rate periods relevant to this proceeding.**

21 A. This proceeding covers the Company's PGC costs for the historic period (April 1, 2024 –
22 March 31, 2025), the interim period (April 1, 2025 – November 30, 2025) and the PGC
23 projected period (December 1, 2025 – November 30, 2026).

1 **Q. Which portions of Book 1 contain the cost of gas purchases for the three previously**
2 **identified periods?**

3 A. Attachment 1-A-1 contains the historic cost of gas for the period April 1, 2024 through
4 March 31, 2025. Attachment 1-B-1 contains the cost of gas for the interim period April 1,
5 2025 through November 31, 2025. Attachment 1-B-2 contains the projected cost of gas
6 for the period December 1, 2025 through November 30, 2026.

7
8 **Q. What is the total cost applicable to the PGC for the historic period and the projected**
9 **period?**

10 A. The PGC costs for the historic period were \$355.9 million. For the projected period, the
11 projected PGC costs are \$413.6 million.

12

13 **III. UGI Gas's Procurement Policy and Peak Day Demand**

14 **Q. What is UGI Gas's projected firm peak day demand for the upcoming 2025-2026**
15 **winter season?**

16 A. For the upcoming 2025-2026 winter season, the projected firm peak day demand, inclusive
17 of reserve requirement, is 2.328 billion cubic feet (BCF), which includes 2.268 BCF of
18 design-cold firm requirements and 0.060 BCF of capacity reserve requirements. UGI Gas
19 also presents its total projected capacity requirement to meet firm peak day demand through
20 the 2029-2030 winter season (shown in Table 1 below) of 2.378 BCF. This five-year
21 planning horizon serves as the basis for seeking long-term contract options as described
22 further in this section of my testimony, inclusive of this intermediate-year's winter season
23 requirements.

24

1 **Q. What are UGI Gas’s projected firm peak day demands and capacity requirements**
2 **for the next five years?**

3 A. The Company’s five-year projected firm peak day demand and reserve requirements can
4 be found in Table 1 below. The table includes the Company’s currently contracted firm
5 capacity and the associated projected long-term length or shortfall positions, assuming
6 extension of all existing contracts during each period as described in greater detail below.

7 **Table 1: Projected Peak Demand & Capacity (Dth) for 2025-2030**

Winter	Projected Firm Peak Day Demand	Capacity Reserve Requirement (5%) ¹	Capacity Requirements	Current Contracted Firm Capacity/ Supply	Projected Length/ (Shortfall)
2025-26	2,268,404	59,794	2,328,198	2,310,235	(17,963)
2026-27	2,280,283	60,388	2,340,671	2,310,235	(30,436)
2027-28	2,292,162	60,982	2,353,144	2,310,235	(42,909)
2028-29	2,304,041	61,576	2,365,617	2,310,235	(55,382)
2029-30	2,315,920	62,170	2,378,090	2,310,235	(67,855)

8
9 The Company projects a capacity shortfall for the immediate winter season of 17,963 Dth
10 per day, which UGI Gas proposes to address through additional capacity and/or supply
11 sources obtained through RFPs and potential capacity offerings available from pipeline
12 suppliers that are discussed in Section V of my testimony, below.

13
14

¹ The Capacity Reserve Requirement is calculated as 5% of the combined PGC-1 and Choice customer demand requirements as stated in UGI Gas Attachment 14-1 of Book 1

1 **Q. Briefly describe the general methodology UGI Gas uses to project firm peak day**
2 **demand.**

3 A. As part of its PGC, UGI Gas evaluates its contracts in order to ensure it can meet the
4 anticipated design-cold peak day demand of its Core Market customers and firm
5 transportation customers during the 2025-2026 winter and through the 2029-2030 winter.
6 This five-year planning horizon was adopted as part of the UGI Gas 2024 PGC at (Docket
7 No. R-2024-3048828. Additionally, in undertaking the peak day evaluation, the Company
8 uses design-cold temperatures established as part of the Company's prior PGC case
9 settlements at Docket Nos. R-00072335, R-00072334, and R-2009-2105909 for the former
10 South, North, and Central Rate Districts, respectively. These design-cold temperatures are
11 -3.6 degrees Fahrenheit for the former South Rate District and a portion of the former
12 Central Rate District, -6 degrees Fahrenheit for the former North Rate District, and -14
13 degrees Fahrenheit for the remainder of the former Central Rate District

14 Since design-cold peak day temperatures are not experienced each year, and firm
15 customer demand is dynamic, peak day demand forecasts are based on a multi-linear
16 regression analysis of the Core Market's daily demand. The results of the analysis are used
17 to model the Company's demand at the established design-cold temperatures mentioned
18 above. The calculated standard error measure from the regression analyses is then applied
19 to the results to achieve a 95% confidence interval for each former Rate District (i.e., South,
20 Central, North). The standard error is a measure of the accuracy of the model's
21 prediction. The forecast is then adjusted for growth and the known and anticipated
22 contractual peak day firm requirements of the Company's large firm transportation
23 customers.

1 **Q. Why does the Company use design-cold temperatures in its peak day analysis?**

2 A. The Company uses design-cold temperatures to ensure that UGI Gas can meet firm
3 customer demand in reasonably foreseeable but critically cold conditions. These
4 temperatures are representative of the range limit under which the Company’s portfolio is
5 expected to continue reliable performance. Historical weather events, such as Winter Storm
6 Uri in 2021, which affected the entire state of Texas, registered record-breaking low
7 temperatures.² These types of weather events pose a significant risk to reliable service
8 based on the overall demand on the UGI Gas system. Therefore, it is important to anticipate
9 extreme-cold events that exceed the weather experienced in most winters.

10

11 **Q. How does UGI Gas include customer growth in its projected peak day demands for**
12 **Winter 2025-2026 through Winter 2029-2030.**

13 A. UGI Gas has experienced year-over-year growth in the number of Core Market customers
14 it serves and expects that growth to continue for the foreseeable future. In developing its
15 projected peak day demands, UGI Gas adds a projection to the results of its annual design
16 day analysis to account for expected customer additions based on their anticipated peak
17 day usage requirements. In its five-year peak day demand projection, the Company
18 assumes the growth rate will continue, based on the historic trend it has experienced. If
19 the Company did not include this expected Core Market customer growth, it would
20 underestimate peak day demand for projected years.

21

² See <https://www.weather.gov/hgx/2021ValentineStorm>.

1 **Q. Do large firm transportation customers have an impact on the Company's firm peak**
2 **day demand forecast?**

3 A. All Rate DS customers, Rate LFD customers, and Rate XD customers are included in the
4 peak day demand forecast, up to firm contract demand levels. The Company's large firm
5 transportation customers combined Daily Firm Requirements ("DFRs") for the Rate LFD
6 and XD customers and Maximum Daily Quantities ("MDQs") for the Rate DS represent
7 the firm obligations of transportation customers for supply service from the Company.
8 Additions of large firm transportation customers to the Company's distribution system are
9 reviewed on a case-by-case basis for the availability of firm service. As a result, the
10 Company has not included any additional changes beyond the current firm obligations to
11 transportation customers for future periods as part of its firm peak day demand forecast.
12 New large firm transportation customer requests will be a recognized variance to this
13 planning approach.

14
15 **Q. Please explain the capacity planning function and how it applies to UGI Gas's large**
16 **firm transportation customers.**

17 A. Capacity planning is the process of procuring supply and capacity assets to satisfy
18 forecasted peak day or contractual demand. For the large firm transportation customers,
19 their forecasted peak demand is either their DFR or MDQ. UGI Gas acts as the capacity
20 planner for the Rate DS customers, as those customers are assigned UGI Gas supply assets
21 to serve 100% of their MDQs. The Rate LFD customers have an annual election option to
22 choose UGI Gas or their respective Agent or NGS as their capacity planner. Finally, for

1 the Rate XD customers UGI Gas is the capacity planner for a fixed amount of capacity,³
2 but the remainder of the capacity needed to serve Rate XD is obtained by the customer
3 through their NGS or Agent as capacity planner.
4

5 **Q. What contract assumptions are built into the five-year peak day demand forecast?**

6 A. In developing the shortfall analysis, UGI Gas assumes it will renew or replace all existing
7 contracts in its supply portfolio that expire each year between now and the 2029-2030
8 winter. The analysis shown in Table 1 is not adjusted for new contracts that are or would
9 be proposed under UGI Gas’s current approach to capacity planning.
10

11 **Q. What has been the outlook for new pipeline construction projects to the UGI Gas**
12 **market area historically?**

13 A. Over the last four years, there have only been two open seasons for firm pipeline capacity
14 issued by pipelines currently interconnected with UGI Gas for projects that would feasibly
15 deliver to the UGI Gas distribution system. The last open seasons for incremental primary
16 firm capacity with deliverability to UGI Gas where the Company successfully obtained
17 capacity were issued by Texas Eastern Transmission, LP (“Texas Eastern”) in 2017 and
18 the Transcontinental Gas Line Company, LLC (“Transco”) in 2018.⁴ Both of these projects
19 went into service in late 2021, which demonstrates the long timeline associated with
20 securing new interstate pipeline capacity.
21

³ See *Pa. PUC v. UGI Utilities, Inc.*, Docket No. R-009532297 (Order entered August 21, 1995).

⁴ See Testimony of Angelina M. Borelli at *Pa. PUC v. UGI Utilities, Inc.*, Docket No. R-2019-3009647.

1 **Q. How is the Company utilizing its five-year planning horizon as part of its**
2 **procurement practices?**

3 A. The Company is using the fifth year of the five-year peak day demand forecast shortfall of
4 67,855 Dth to establish a capacity target and optimal step-up capacity targets for
5 intermediate years (“Five-Year Plan”).

6
7 **Q. Has the Five-Year Plan been incorporated into the Company’s RFP this year for**
8 **capacity additions?**

9 A. Yes, the Company utilized the Five-Year Plan to quantify its firm peak day requirements
10 across this extended planning horizon to outline requirements for consideration by the RFP
11 bidders. This approach will provide the Company with a view of available options to
12 address short and long-term capacity needs.

13
14 **IV. Choice Program Update**

15 **Q. Please summarize the changes being made to UGI Gas’s Choice Supplier tariff.**

16 A. The Company is filing a tariff change to update the peak day allocation percentages of the
17 Company’s supply portfolio that is provided to NGSs serving Choice customers. These
18 allocations include firm transportation capacity, storage in the form of a bundled sale, and
19 peaking service. The proposed changes to the Company’s Supplier tariff are reflected in
20 the pro forma Tariff Supplement to Tariff Gas-Pa. P.U.C. No. 7 and 7S, filed in this
21 proceeding on May 30, 2025).

22

23

24

1 **Q. Why are there changes being made to the peak day allocations?**

2 A. UGI Gas acts as the capacity planner for its Core Market Customers, which include both
3 PGC and Choice customers. In this role, the Company maintains a portfolio designed to
4 meet the design-firm requirements for its Core Market customers. NGSs serving customers
5 participating in the Company's Choice program receive an allocation of the Company's
6 firm transportation capacity and an allocation of delivered supply, storage supplies, and
7 peaking supplies. UGI Gas is updating the peak day allocation percentages of these supply
8 assets to reflect the 2025-2026 supply portfolio, as shown on Attachment 14-1 of Book 1.

9

10 **V. Recent Contract Renewals**

11 **Q. Please describe the agreements that comprise the Company's supply portfolio.**

12 A. The Company manages a portfolio of firm transportation, delivered supplies, storage, and
13 peaking agreements. Many of these agreements were initiated through long-term contracts
14 that permit the Company to continue service upon expiration of the initial term through
15 automatic "evergreen" renewals, by exercising a Right of First Refusal ("ROFR") or by
16 exercising a right to extend the service for an agreed upon term and price adjustment.

17

18 **Q. Please describe the agreements in the Company's supply portfolio that were renewed.**

19 A. Table 2 below summarizes the contracts that were renewed during the historic review
20 period (i.e. April 1, 2024 to March 31, 2025). UGI Gas Exhibit JRT-2 provides a detailed
21 list of each agreement that includes the service type, annual cost, and renewal term.

22

1

Table 2: Summary of Contract Renewals During Historic Period

Supplier	Renewal Type	Service	Maximum Daily Quantity (Dth)
Columbia	Extension	Transportation/Storage	134,223
EGTS	Extension	Transportation/Storage	10,667
Supplier J	Evergreen	Delivered Supply	800
Supplier M	Extension	Delivered Supply	1,680
Tennessee	Extension	Transportation	6,068
Texas Eastern	Evergreen	Transportation/Storage	247,021
Transco	Evergreen	Transportation/Storage	60,664
UGIES	Extension	Peaking	45,404

2

3 **Q. Please describe the Company’s rationale for renewing these service agreements.**

4 A. The Company will renew service agreements that are needed to meet the its design firm
5 capacity requirements, are reliable, and are at the lowest cost. As the demand for natural
6 gas supply has significantly increased over the last ten or so years, so has the need for
7 additional pipeline infrastructure. As a result, the interstate pipelines serving the
8 Company are generally fully subscribed and cannot provide new service without
9 construction of an expansion project. When interstate pipelines initiate construction
10 projects for new supply, they are typically more expensive than the Company’s existing
11 services, require a lead time of many years, and are subject to FERC approval. In recent
12 years it has become increasingly difficult for new interstate pipeline capacity to be

1 constructed, so renewing existing capacity and storage contracts is very important to the
2 Company in meeting its firm service obligations.

3
4 **Q. Please describe the services that were renewed through evergreen provisions.**

5 A. The Company holds firm transportation and storage agreements with Tennessee, Texas
6 Eastern, and Transco that provide primary firm supply required to meet the Company's
7 firm demand requirements. The contracts for these services include evergreen provisions
8 that automatically extend the agreements upon expiration of the termination date unless the
9 Company chooses to terminate the agreements. The Company chose to extend the service
10 agreements, as it was unaware of any lower cost alternatives to replace these services, based
11 on the pipeline capacity offerings discussed earlier in my testimony.

12
13 **Q. Please describe the services that were renewed through a ROFR.**

14 A. The Company renewed the following services by exercising ROFR provisions in existing
15 contracts:

16 **Table 3: Contracts Renewed Through ROFR**

Contract	MDQ	Term End Date	Notice Date	Demand Rates (\$/Dth)	Term Extension
EGTS FT - 700117	2,000	3/31/2025	3/31/2024	\$65	5 Years
EGTS GSS - 300126	8,667	3/31/2025	3/31/2023	\$63	5 Years
EGTS GSS - 300225	2,000	3/31/2025	3/31/2023	\$63	5 Years
Columbia FSS - 79028	126,473	3/31/2025	9/30/2024	\$70	5 Years
Columbia SST - 79133	126,473	3/31/2025	9/30/2024	\$95	5 Years

Columbia FTS - 80021	21,500	10/31/2025	4/30/2025	\$128	5 Years
Columbia FTS - 229154	7,750	3/31/2025	9/30/2024	\$128	5 Years

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Q. Please describe the services that may be renewed through a ROFR within the next year.

A. The Company is contemplating renewing the following services by exercising ROFR provisions in existing contracts:

Table 4: Future Contract Renewals Through ROFR

Contract	MDQ	Term End Date	Notice Date	Demand Rates (\$/Dth)	Term Extension
EGTS FT - 200796	2,000	3/31/2026	9/30/2025	\$72	5 Years

Q. Please describe the agreements in UGI Gas supply portfolio that are proposed for renewal within the next year.

A. UGI Gas Exhibit JRT-3 provides a detailed list of each agreement that includes the service type, annual cost, and renewal term.

Q. Will UGI Gas issue an RFP seeking replacement of any the agreements listen in UGI Gas Exhibit JRT-3 within the next year?

A. Based on market assessment, the Company has not identified any agreements that will not continue to meet its least cost obligations, thus it is planning for renewal of these upcoming contracts without the need to RFP.

1 **VI. Supply RFPs**

2 **Q. Has the Company issued any RFPs for natural gas capacity supplies since the last**
3 **PGC proceeding?**

4 A. Yes. The Company has issued several RFPs since the last PGC proceeding. Specifically,
5 as discussed further in this section of the testimony, the Company issued RFPs to address
6 its projected capacity shortfall beginning in the winter of 2025-2026 through 2029-2030;
7 for three separate Asset Management Agreements for portions of UGI Gas's TETCO FT
8 capacity, Transco FT capacity and EGTS GSS capacity; and an RFP for a mobile LNG
9 solution. This Supply RFP section also discusses interstate pipeline offers and open
10 seasons received in the last year.

11

12 **A. UGI Gas's RFP Process**

13 **Q. Please describe the Company's supply RFP process.**

14 A. The Company updates its design day study each April, and if a capacity shortfall is
15 projected, the Company will issue an RFP to address the shortfall. From time to time, the
16 Company will also issue RFPs for a particular service as needed. As part of prior PGC
17 proceedings, the Company has adjusted its process related to bidding periods, payment
18 terms, and advanced notification to potential suppliers in order to support robust RFP
19 participation. The Company posts the RFPs on its Energy Management Website and
20 circulates them to a distribution list of potential suppliers to solicit interest.

21

22

1 **Q. Did UGI Gas include terms in its RFPs that were agreed upon in previous PGC**
2 **Settlements?**

3 A. Yes. I will describe the Company's RFPs and their compliance with past settlement
4 commitments in this section of my testimony.

5
6 **Q. Please describe the provisions specified in the Company's RFPs for peak day supply.**

7 A. The RFPs explain that UGI Gas will entertain pricing provisions for needed services that
8 are based on either the New York Mercantile Exchange ("NYMEX") or an index such as
9 Platts Gas Daily. In either case, the pricing provision includes a link to a transparent pricing
10 point. Further, consistent with UGI Gas's reliability obligations and past practices, the
11 RFPs specify that conforming bids will meet the following:

- 12 • Supplies must be backed with physical assets.
- 13 • Assets must have a primary firm delivery point into UGI Gas's distribution
14 system.
- 15 • Service must include a roll-over provision to extend the contract.
- 16 • Supplier(s) must agree to partial awards; and
- 17 • Supplier(s) must agree to enhanced force majeure provisions.
- 18 • Suppliers(s) must agree to maintain bids until formal Commission approval
19 for new supply additions to the Company's portfolio.
20

21 In accordance with the Company's 2020 PGC Settlement at Docket No. R-2020-3019680
22 ("2020 Settlement"), the Company requested payment terms of December through March
23 and November through March in its April 2025 Capacity Shortfall RFP so that any related
24 pricing options may be evaluated by the Company.

25

1 **Q. Does UGI Gas have any notice provisions surrounding its annual RFPs?**

2 A. Yes. In accordance with the 2020 Settlement, the Company posted advance notice of its
3 annual RFP on its Energy Management Website on January 30, 2025, and provided notice
4 to its interstate pipeline providers.

5

6 **Q. Has the Company concluded its three-year pilot study per the 2021 PGC Settlement**
7 **at Docket No. R-2021-3019680 for modified payment terms in its RFPs?**

8 A. Yes. From 2021 through present day, UGI Gas requested that bidders provide demand
9 charge payment term options for both November through March and December through
10 March. During this pilot study, UGI Gas did not receive any bids that provided both a four
11 month and a five month payment option for the same service. As a result, the Company is
12 unable to perform a comparison of related interest costs differences for the same product
13 offering made in response to RFP.

14

15 **Q. Does the Company have a recommendation on the three-year pilot program for**
16 **modified payment terms?**

17 A. UGI Gas's recommendation is to continue the pilot program for an additional period of
18 time, as there was not enough information gained during the initial term of the pilot to make
19 a reasonable recommendation.

20

21 **Q. Why must the supplies be asset-backed?**

22 A. Having the supplies backed by a demonstrated asset provides a level of security that ensures
23 the Company can reliably fulfill its role as a supplier of last resort to Core Market

1 customers. UGI Gas performs asset verifications for each supplier and reviews each
2 supplier's underlying sources of supply, primary receipt points, primary delivery points
3 and associated delivery point rights. Without the appropriate contract attributes, a supplier
4 does not have the contractual rights with an interstate pipeline to fulfill its firm obligations
5 under peak or design conditions.

6
7 **Q. What is the benefit of pipeline assets that have a primary firm delivery point into the**
8 **UGI Gas system?**

9 A. The benefit of primary firm delivery points is the lowest risk of interruption or restriction
10 by the pipelines. Pipelines rank other nominations, including secondary firm deliveries, as
11 interruptible or of lower priority, which means these nominations can be unreliable during
12 peak periods. Secondary deliveries, including what would be considered secondary "in-
13 path," have been restricted by some pipelines. Further, pipeline contracts with primary firm
14 delivery points carry delivery point rights that allocate capacity at specific meters or gate
15 stations. Without these delivery point rights, pipelines could restrict deliveries at specific
16 meters. Therefore, capacity that is primary firm provides the highest level of security of
17 supply, especially under peak day conditions. Wherever possible, UGI Gas seeks to
18 acquire or amend contracts to obtain primary firm delivery.

19
20 **Q. Why do UGI Gas's RFPs request enhanced force majeure provisions in the contract**
21 **proposals?**

22 A. UGI Gas requests enhanced force majeure provisions because there are differing
23 definitions of firm service throughout the industry. These enhanced contractual provisions

1 prevent certain supplier arbitrage scenarios (e.g., cutting a supply on the basis of an alleged
2 weather-related force majeure event and then selling the gas that would have been delivered
3 to the Company in another market at a higher price).

4
5 **Q. What other protections are provided by enhanced force majeure provisions?**

6 A. When UGI Gas reserves pipeline capacity to an upstream location with liquid trading, it
7 still makes every effort to limit the possibility of price arbitrages in the standard North
8 American Energy Standards Board (“NAESB”) contracts it uses. However, in the event of
9 non-performance, the Company maintains price protections under these provisions for
10 replacement supplies. Delivered services to UGI Gas’s city gates during peak cold periods
11 can be subject to extreme price volatility. By including the enhanced force majeure
12 provision in the RFP, UGI Gas is assured that potential bidders have a clear expectation of
13 the required level of service and understand the full pricing obligation of the transactions.

14
15 **Q. Why is it important to require a contract extension provision in the RFPs?**

16 A. Having the right to extend or roll-over the contract provides supply certainty beyond the
17 initial term of the contract. This provision is similar to ROFR provisions and simple roll-
18 over provisions in pipeline contracts. Contract extension provisions ensure that the
19 capacity will be available to UGI Gas even if the primary term of the contract expires.
20 Contract extension terms also provide an effective hedge against a tightening capacity
21 market.

1 **Q. Why is it important that a Supplier agree to a partial award?**

2 A. This provides the Company with flexibility that may be needed to address tailoring awards
3 to specific peak day requirements.

4
5 **Q. Why is it important that a Supplier agree to maintain their RFP bids until formal
6 Commission approval when bidding for supply additions to the portfolio?**

7 A. This provides the Company with assurance throughout the 1307(f) proceeding that related
8 information presented is open for prudent review until a final Commission determination
9 is made.

10

11 **Q. What happens if a bid is received that does not conform to the provisions identified
12 above?**

13 A. Bids received in an RFP that do not conform with one or more of the provisions above are
14 deemed non-conforming. During the bid review process, bids are evaluated and ranked by
15 their level of conformity and least cost nature of the offers. Non-conforming bids would
16 only be considered for award if there were no available conforming bids.

17

18 **B. Supply Shortfall RFP Results**

19 **Q. Please describe the Company's peak day capacity RFP.**

20 A. Annually, UGI Gas reviews its peak day needs based on anticipated design cold conditions,
21 as described in Section III of my testimony. Where the Company identifies a shortfall, it
22 then seeks firm supply to address that shortfall. As UGI Gas has seen significant customer
23 growth year over year, there is often a need to address additional requirements.

1 **Q. What volume of supply did the Company seek to acquire in its RFP?**

2 A. UGI Gas sought from 17,963 Dth/day up to 57,855 Dth/day of capacity, primarily on
3 Transco, although the Company was willing to evaluate other options. These volumes
4 represent the capacity requirements through 2030.

5
6 **Q. How many responses did UGI Gas receive to the RFP?**

7 A. UGI Gas received three responses to the RFP.

8
9 **Q. What method did the Company use to evaluate the bids received?**

10 A. The bids are first evaluated to determine if they were conforming bids by meeting the
11 requirements of the RFP. Those requirements are that the offer (1) is firm and backed by
12 assets; (2) can be delivered in the area needed to address the supply shortfall; (3) complies
13 with the enhanced force majeure provisions; (4) provides for an extension of the contracts;
14 (5) is subject to partial award; and (6) is valid until formal Commission approval for new
15 supply additions to the Company's portfolio. UGI Gas then awards the capacity to the least
16 cost offer that meets the requirements of the RFP.

17
18 **Q. Is UGI Gas requesting approval for any bids associated with its RFP?**

19 A. UGI Gas continues to evaluate the bids received in this RFP. Additional review of the bids
20 is required to analyze the best option on the basis of least cost and reliability. UGI Gas is
21 discussing terms with the bidders from this RFP to optimize the offerings for PGC
22 customers. The Company will present the full RFP outcome as soon as it is available.

1 **Q. How will the Company continue to address the long-term capacity needs within the 5**
2 **year planning horizon?**

3 A. UGI Gas will maintain ongoing discussions concerning the long-term supply needs of the
4 Company with the interstate pipelines and explore opportunities for additional capacity, as
5 well work with the recent bidders in the RFP to develop opportunities for future supply
6 needs. UGI Gas will also consider the potential for internally developed projects that can
7 address this supply shortfall in the future periods. UGI Gas will perform ongoing RFPs at
8 appropriate times for any capacity shortfall amounts unfilled for years 2026-2030 and
9 evaluate the supply options at that time. UGI Gas will provide ongoing updates each PGC
10 proceeding.

11

12 **C. AMA RFP**

13 **Q. What is an Asset Management Agreement?**

14 A. An Asset Management Agreement (“AMA”) is a contractual relationship through which a
15 party consents to manage delivery arrangements, including supply, as well as the
16 transportation of gas, for another party. In an AMA, the owner of firm interstate pipeline
17 capacity or storage assets releases its capacity to the asset manager for a specified term. By
18 entering into an AMA, the owner of the capacity receives an administrative fee while still
19 benefitting from the ability to call on the operational capabilities of the capacity to fulfill
20 system supply requirements. In situations where UGI Gas is releasing capacity as part of
21 an AMA, rights to recall the capacity or storage asset are maintained, and financial security
22 is required, in order to safeguard UGI Gas customers from non-performance which could
23 impact reliability.

1 Under UGI Gas's incentive sharing mechanism, the administrative fee paid by an
2 asset manager to UGI Gas is shared with PGC customers. Specifically, 75% of the fee is
3 credited to the PGC and 25% is retained by UGI Gas. As a result of UGI Gas securing an
4 asset manager for its capacity, PGC customers will experience reduced PGC costs versus
5 what would otherwise have been experienced without the AMA.
6

7 **Q. Did UGI Gas have any new AMAs on interstate pipeline capacity during the historic**
8 **period?**

9 A. Yes. UGI Gas had two new AMAs during the historic period. The first for 10,000 Dth of
10 Transco FT capacity for the period from April 1, 2024, through March 31, 2025, and the
11 second for 20,000 Dth of TETCO FT capacity for the period from January 1, 2024 through
12 December 31, 2024. Both AMAs were identified in the Company's 2024 PGC proceeding.
13

14 **Q. Did UGI Gas issue any RFPs for additional AMAs in the historic period?**

15 A. Yes, UGI Gas issued an RFP to continue the AMA associated with the 10,000 Dth of
16 capacity on Transco that was set to expire March 31, 2025. That RFP was issued on March
17 4, 2025. UGI Gas received many responses to its AMA with competitive bids. It selected
18 the highest bidder and awarded the AMA. The current Transco AMA runs from April 1,
19 2025, to March 31, 2026. In addition, UGI Gas also issued an RFP to continue the AMA
20 associated with the 20,000 Dth of capacity on Texas Eastern on November 21, 2024. UGI
21 Gas received competitive offers, and the Company awarded the AMA to the highest bidder.
22 The Texas Eastern AMA runs from January 1, 2025, to December 31, 2025. Lastly, UGI
23 Gas also issued an RFP for 3,400,000 Dth of storage capacity on EGTS on October 3, 2024.

1 UGI Gas received competitive offers, and the Company awarded the AMA to the highest
2 bidder. The Eastern Gas AMA runs from November 15, 2024, to October 31, 2027. The
3 results from the three AMA RFPs are included with my testimony as UGI Gas Exhibit JRT-
4 4.

5
6 **Q. What is the total benefit to the PGC from the three AMAs?**

7 A. PGC customers will receive a total of \$4,651,500 in revenue credits over the term of the
8 three AMAs, calculated consistent with the Company's Revenue Sharing Incentive
9 Mechanism ("RSIM") contained in Rider B – Section 1307(f) Purchase Gas Cost of Tariff
10 Gas-Pa. P.U.C. No. 7 and 7S. The credit to the PGC is reflected in Book 1 in Attachment
11 1-B-1 and Attachment 1-B-2 on line item "Non-Choice Cap Rel/Sharing Mech Credit."

12
13 **D. Mobile LNG RFP**

14 **Q. Did UGI Gas issue an RFP for mobile LNG?**

15 A. Yes. UGI Gas issued an RFP for mobile LNG service to Jim Thorpe, PA on May 20, 2025.
16 In 2015 and 2020, the Company acquired a mobile LNG service to supply the Jim Thorpe
17 area. The service provided the Company with LNG supplies, LNG storage and
18 vaporization equipment, and staffing to run the LNG facility. The most recent service
19 agreement expired on March 31, 2025. The Company plans to continue to use mobile LNG
20 supply to support the continued provision of reliable service to Jim Thorpe. The bids are
21 due for this RFP by June 3, 2025.

1 **Q. Will UGI Gas issue any other RFPs for mobile LNG during the future period?**

2 A. Yes. UGI Gas plans to issue an RFP to serve the Hobbie transmission pipeline near
3 Humboldt, PA.

4
5 **Q. Why is the mobile LNG service needed for the Hobbie transmission line?**

6 A. As a result of pipeline integrity requirements, Mobile LNG is needed to maintain minimum
7 system pressures during peak day conditions when the pipeline supplier's pressure drops
8 below 600 psig. UGI Gas is complying with federal requirements by conducting Maximum
9 Allowable Operating Pressure (“MAOP”) reconfirmation for sections of the 8" Hobbie
10 transmission pipeline. Sections of the pipeline will be isolated and pressure tested. Mobile
11 LNG is needed to provide customers with natural gas supply while sections of the 8"
12 Hobbie transmission pipeline are taken out of service to perform the pressure testing.

13

14 **E. Interstate Pipeline Capacity Opportunities**

15 **Q. Did any of the interstate pipeline providers offer available capacity to the market for
16 the upcoming winter?**

17 A. Yes.

18

19 **Q. Please describe the offering.**

20 A. Texas Eastern Transmission Corp. (“TETCO”) issued an Open Season on November 5th,
21 2024, with bids due by December 20, 2024. The Open Season sought bidders for available,
22 unsubscribed capacity not subject to ROFR for 150,000 Dth/day of deliverability to the
23 Lower Chanceford interconnection with the Transcontinental Gas Pipeline (“Transco”),

1 referred to as the TEMAX Capacity, with the capacity being available November 1, 2025.
2 This capacity does not deliver directly to UGI Gas but could be utilized on a primary firm
3 path to deliver supply into the Company's existing Transco Sentinel expansion capacity of
4 7,000 Dth/day.

5
6 **Q. How does the TEMAX capacity support the existing UGI Gas capacity portfolio?**

7 A. UGI Gas acquired the Transco Sentinel capacity in 2005, prior to the increased natural gas
8 production in the Marcellus and Utica shale formations. During that time period, it was
9 projected that UGI Gas would be purchasing natural gas imports via the Cove Point LNG
10 terminal. The Sentinel capacity provided a firm pathway for UGI Gas to receive, transport,
11 and ultimately deliver imported natural gas from the Cove Point facility.

12 Without the need for LNG imports and the availability of affordable,
13 geographically close domestic supplies, UGI Gas has not needed to use its Sentinel
14 capacity. As such, UGI Gas continues to release the Sentinel capacity to interested market
15 participants each year. UGI Gas has removed the Sentinel capacity from its design day
16 supply build up as a result of the capacity releases and the lack of economically viable,
17 firm supply sources at Cove Point.

18 The TEMAX capacity of this open season has receipts in the TETCO M2 zone,
19 which includes the Marcellus and Utica shale production region, with deliverability to an
20 interconnection with Transco at Lower Chanceford. The Lower Chanceford receipt point
21 on Transco is in-path of UGI Gas's Sentinel capacity and is considered a primary receipt
22 point for supplies on Transco. With the TEMAX capacity, UGI Gas would be able to
23 achieve a primary path for receipt supplies on TETCO with redelivery on Transco to the

1 UGI Gas Transco gate stations via the TEMAX and Sentinel capacity. At the currently
2 available rates, the path of the TEMAX and Sentinel capacity would carry a combined
3 reservation charge of approximately \$1.083/Dth/day. However, considering the Sentinel
4 capacity is already in the UGI supply portfolio and already captured by the PGC, the only
5 incremental cost is the prospective TETCO TEMAX capacity.
6

7 **Q. Did UGI Gas bid on the TETCO Open Season?**

8 A. Yes. UGI Gas reviewed the Open Season and recognized the benefit of the TEMAX
9 transportation capacity as a way for UGI Gas to utilize its existing Sentinel Capacity. UGI
10 Gas submitted a bid of 7,050 Dth/day of the TETCO TEMAX capacity for up to 14 years
11 and 5 months; a term beginning November 1, 2025, and expiring March 31, 2040. The
12 7,050 Dth/day would provide sufficient deliverability into the Transco Sentinel capacity
13 after accounting for the Zone 6 to Zone 6 transportation retainage rates on the Transco
14 system such that UGI Gas can then redeliver the full 7,000 Dth/day of existing Sentinel
15 capacity. The filed rate of the TEMAX capacity was \$0.533/Dth/day at the time of the open
16 season.
17

18 **Q. What was the result of the TETCO Open Season?**

19 A. UGI Gas was not selected as a winning bidder and did not acquire the TEMAX capacity as
20 another market participant acquired this capacity via a bid which evaluated at a higher Net
21 Present Value (“NPV”). UGI Gas will continue to evaluate opportunities for pipeline
22 capacity through open seasons or opportunities through capacity releases with contracted
23 shippers.

1 **VII. Participation in FERC Proceedings**

2 **Q. Please describe UGI Gas’s participation in FERC proceedings.**

3 A. UGI Gas’s primary FERC activities include participation in Natural Gas Act Section 4
4 base rate proceedings, rulemakings and certificate proceedings before FERC. UGI Gas
5 also engages in direct negotiations with pipelines. FERC orders in any proceedings
6 impacting pipelines could change UGI Gas’s purchased gas costs during the next twenty
7 months.

8

9 **Q. Have any new significant proceedings been filed at FERC since the 2024 PGC**
10 **proceeding that could impact UGI Gas’s PGC customers?**

11 A. Yes, there have been a number of filings made at FERC in the past year, including two
12 pipeline Section 4 proceedings, which will impact transportation and storage services used
13 by UGI Gas. In addition to these new proceedings, UGI Gas has continued to monitor and
14 participate in major dockets that have industrywide significance.

15

16 **A. Transcontinental Gas Pipe Line Company Section 4 Rate Case**

17 **Q. Please describe the Section 4 rate case filed by Transcontinental Gas Pipe Line**
18 **Company.**

19 A. Transco filed a Section 4 rate case on August 30, 2024 at Docket No. RP24-1035 to
20 facilitate rate changes under its firm, interruptible, and storage services to be effective
21 March 1, 2025. On September 30, 2024, FERC accepted and suspended Transco’s revised
22 tariff records, subject to a refund after the outcome of a hearing.

23

1 **Q. Is UGI Gas actively participating in the Transco rate case?**

2 A. Yes, UGI Gas is an active participant in the Transco rate case. The Company joined a
3 customer group consisting of local distribution companies (“LDCs”) and participates in the
4 proceeding by contributing to the discovery process and the development of testimony. In
5 addition, the Company actively participates in settlement negotiations.

6

7 **Q. Have Transco’s rates gone into effect?**

8 A. Yes, the proposed rates went into effect on March 1, 2025, subject to refund at the
9 conclusion of the proceeding.

10

11 **Q. What is the resulting impact to the Company’s demand charges?**

12 A. The Company is currently being assessed Transco’s proposed rates. On an annual basis,
13 UGI Gas anticipates that Transco’s filed rates will increase costs to the Company by \$6.2
14 million. When a final order is entered in this proceeding, any reduction in rates will be
15 applied retroactively to March 1, 2025. If there is any difference in the Company’s demand
16 costs at the conclusion of the case, this difference will be calculated, including interest, and
17 a refund will be owed to the Company that reflects the period from March 1, 2025 until the
18 new rates take effect. Any rate refund received by the Company will then be flowed back
19 to customers.

20

21

22

1 **B. Columbia Gas Transmission Section 4 Rate Case**

2 **Q. Please describe the Section 4 rate case filed by Columbia Gas Transmission.**

3 A. Columbia Gas Transmission (“Columbia”) filed a Section 4 rate case on September 30,
4 2024 at Docket No. RP24-1103 to facilitate rate changes under its firm, interruptible, and
5 storage services to be effective April 1, 2025. On October 31, 2024, FERC accepted and
6 suspended Columbia’s revised tariff records, subject to a refund after the outcome of a
7 hearing. In the filing, Columbia presented two rate design scenarios – the proposed case
8 with rates reflective of its current postage stamp rate design, and the preferred case with
9 rates reflective of a two-zone rate design. Additionally, Columbia proposed non-rate tariff
10 changes, including hourly flow restrictions, elimination of contractual ROFR rights, and
11 expanded penalty provisions.

12
13 **Q. Is UGI Gas actively participating in the Columbia rate case?**

14 A. Yes, UGI Gas is an active participant in the Columbia rate case. The Company joined a
15 customer group consisting of LDCs and participates in the proceeding by contributing to
16 the discovery process and the development of testimony. In addition, the Company actively
17 participates in settlement negotiations.

18
19 **Q. Have Columbia’s rates gone into effect?**

20 A. Yes, the proposed rates went into effect on April 1, 2025, subject to refund at the conclusion
21 of the proceeding. The non-rate tariff provisions have not yet been made effective, as a
22 condition of ongoing settlement discussions.

1 **Q. What is the resulting impact to the Company's demand charges?**

2 A. The Company is currently being assessed Columbia's proposed rates. On an annual basis,
3 UGI Gas anticipates that Columbia's proposed rates will increase costs to the Company by
4 \$43.5 million. However, if Columbia's preferred zonal rate design goes into effect as a
5 result of this proceeding, UGI Gas estimates that annual costs to the Company will increase
6 by \$52.7 million. When a final order is entered in this proceeding, any reduction in rates
7 will be applied retroactively to April 1, 2025. The difference in the Company's demand
8 costs over this period will be calculated, including interest, and a refund will be owed to
9 the Company. Any rate refund received by the Company will then be flowed back to
10 customers.

11

12 **Q. What are the relevant impacts of the non-rate tariff provisions proposed in**
13 **Columbia's Section 4 proceeding?**

14 A. Columbia's proposed non-rate tariff provisions include 1/24 hourly takes, the elimination
15 of contractual ROFR rights, and expanded storage penalty provisions. Each proposed non-
16 rate tariff provision will place increased operational hardship and risk on the Company.
17 The 1/24 hourly takes provision will limit the hourly volume the Company can obtain from
18 Columbia's system to 1/24 of its contractual maximum daily quantity. As discussed later
19 in my testimony, this would require the application and/or procurement of additional assets
20 to meet peak hourly demand. The elimination of contractual ROFR rights will remove a
21 party's ability to automatically renew an expiring contract at the end of its term, and
22 instead, that capacity will be open to the market for bid. This provision itself can have long
23 lasting and damaging impacts to the Company's Columbia contracts, where the loss of

1 ROFR can lead to a loss of key assets in a relatively short period of time with no recourse.
2 The proposed storage penalty provisions add additional indices that can be used by
3 Columbia to calculate penalty charges and give Columbia the right to confiscate any
4 volume of gas in storage over the daily, monthly, or seasonally allowed quantities.
5

6 **VIII. Renewable Natural Gas – Pilot Program Update**

7 **Q. Can you provide an update on the Renewable Natural Gas Pilot Program?**

8 A. Yes. UGI Gas purchased 303,606 dth of RNG from April 2024 through March 2025. The
9 total cost of the RNG during that period was \$5,039,067. PGC customers received an offset
10 of \$3,795,075 through Renewable Identification Number (“RIN”) monetization over that
11 same period, calculated pursuant to the settlement in Docket Number R-2021-3025652.
12 The net cost of RNG to PGC customers during this period was \$1,243,992. The RIN
13 monetization offset resulted in no net cost impact to the PGC above otherwise applicable
14 supply market pricing, as calculated pursuant to the settlement provisions established for
15 this RNG purchase. The BTU content of the RNG purchased as part of the pilot program
16 was 987 BTU/CF.
17

18 **IX. Hedging Policy Review**

19 **Q. Please describe the Company’s commitments regarding its hedging program**
20 **stemming from the settlement in the 2022 PGC proceeding at Docket No. R-2022-**
21 **3032242, and in the 2023 PGC proceeding at Docket No. R-2023-3040290.**

22 A. In its 2022 PGC proceeding, UGI Gas agreed to undertake a review of its existing hedging
23 program. Specifically, the Company agreed to the following:

1 UGI Gas will hire a consultant to evaluate the performance of its hedging
2 plan in order to identify areas where it may further mitigate customer
3 exposure to significant market volatility. UGI Gas will provide the results
4 of its analysis and any proposed modifications to its hedging plan in its 2023
5 PGC proceeding. The costs for hiring the consultant will be recovered
6 through the PGC and will be capped at \$80,000.00.
7

8 *See Joint Petition for Settlement of Section 1307(f) Rate Investigation* from Docket No R-
9 2022-3032242 (Order entered September 9, 2022). UGI Gas selected Gelber & Associates
10 (“Gelber”) as the consultants to complete the hedge study. As a result of the study
11 conducted by Gelber and presented in its 2023 PGC, UGI Gas agreed to conduct a further
12 investigation into price-trigger driven hedge activities and agreed to report in the 2024 PGC
13 on whether UGI Gas should incorporate that element into the Company’s hedging policy.

14 Specifically, the Company agreed to the following:

15 UGI Gas will investigate price-trigger driven hedge activities and provide a report
16 in the 2024 PGC on whether to incorporate price-trigger driven hedging into the
17 Company’s hedging policy. As part of this investigation, UGI Gas may retain a
18 consultant. The costs for hiring the consultant will be recovered through the PGC
19 and will be capped at \$35,000.
20

21 *See Joint Petition for Settlement of Section 1307(f) Rate Investigation* from Docket No R-
22 2023-3040290 (Order entered August 16, 2023).
23

24 **Q. Please describe the Company’s commitments regarding its hedging program**
25 **stemming from the settlement in the 2024 PGC proceeding at Docket No. R-2024-**
26 **3048828.**

27 A. The recommendations from that study were presented in the 2024 PGC proceeding,
28 including a 4-year pilot program. Specifically, the Company agreed to the following:

29 The Company will implement the recommendations provided in Gelber &
30 Associates’ Trigger Price Study (“Study”), conducted per the 2023 PGC Settlement
31 (Docket No. R-2023-3040290) by way of a 4-year pilot commencing on January 1,

1 2025. The recommendations from the Study, described on pages 36-37 of UGI Gas
2 St. No. 2, include:

- 3 a. Change the strategy of the current hedge program from an even distribution of
4 monthly hedge purchases to a plan that is flexible and has “trigger hedge” amounts
5 that are more heavily weighted towards months where the futures prices have
6 historically been lower than other purchasing months; and
7 b. Revise the current schedule for hedge purchases from fixed days on a weekly basis
8 to a market data-driven and informed, analytical determination of the most effective
9 days within each month to purchase hedge positions.

10
11 During the pilot, UGI Gas will compare the actual cost of the hedging activities set
12 forth in the Study’s recommendations against the performance that would have
13 otherwise occurred under the Company’s existing programmatic approach to
14 hedging purchases.

15 UGI Gas will hire a consultant, through an RFP process, to implement these
16 recommendations and collect and analyze the data needed to compare the pilot
17 against UGI Gas’s programmatic methodology. The Company will recover these
18 consultant costs, related to implementing the recommendations of the Study, as well
19 as analyzing and comparing the pilot data to UGI Gas’s programmatic hedging
20 approach in PGC rates.

21 *See Joint Petition for Settlement of Section 1307(f) Rate Investigation* from Docket No R-
22 2024-3048828 (Order entered October 10, 2024).

23
24 **Q. Did the Company implement the Pilot program by hiring a consultant?**

25 A. Yes. In November 2024, UGI Gas issued an RFP for a commodity hedging manager
26 beginning January 2025 and selected a hedging manager.

27
28 **Q. What other considerations to the 2024 PGC Settlement are included in the pilot?**

29 A. UGI Gas continues to monitor the performance of the hedging program as directed by
30 Gelber versus the performance of the previous programmatic hedging program. UGI Gas
31 will report on the result of that analysis in future PGC proceedings as appropriate.

1 **X. Hourly Flows**

2 **Q. Please describe what is meant by “hourly flows” as it relates to the procurement and**
3 **physical delivery of natural gas supplies.**

4 A. Natural gas supplies are traditionally procured, nominated, scheduled, and confirmed on a
5 daily basis in accordance with NAESB gas scheduling cycles. Under this industry standard,
6 which was implemented over 30 years ago, the quantities of natural gas procured cover an
7 entire 24-hour Gas Day. However, the physical flow of natural gas is continuous and
8 fluctuates throughout the day based on changing customer demands, system operating
9 pressures, weather patterns, and interstate pipeline operations. Interstate pipelines manage
10 these continuous flows through several operational tools, including physical gas storage,
11 compressor stations, line pack management, and the scheduling process. The objective is
12 to balance the daily procurement of supply with the accumulated physical flow over the
13 course of the Gas Day. While daily procurement is the standard, "hourly flows" refers to
14 the more granular management of gas deliveries on an hourly basis. Converting daily
15 supply to an hourly basis is straightforward mathematically - dividing the daily quantity by
16 24 hours. For example, a daily procurement of 48,000 Dth to a particular delivery point
17 would equate to 2,000 Dth per hour (the "Hourly Quantity" or "HQ"). However, actual
18 physical consumption rarely follows this even 1/24th pattern, creating operational
19 challenges when pipeline operators impose hourly flow restrictions.

20

21

22

1 **Q. Do hourly flows pose a risk for UGI Gas, and why is this issue important for the**
2 **Commission to understand?**

3 A. Yes, hourly flow restrictions pose significant operational and reliability risks for UGI Gas
4 and ultimately its customers. These risks exist because:

5 1. The gas industry infrastructure and scheduling systems were primarily designed
6 around daily, not hourly, supply management. Current industry standards and
7 interstate pipeline Electronic Bulletin Boards (EBBs) do not fully support
8 procurement and scheduling at an hourly level.

9 2. UGI Gas's distribution system experiences significant hourly demand variations.
10 At certain delivery points, peak hourly flows can exceed the mathematical 1/24th
11 hourly average by 30% or more, particularly during morning hours when residential
12 heating demand surges.

13 3. UGI Gas plans its design day or peak day around the peak daily flow through its
14 system, not peak hourly flow. If the Company were required to procure supply
15 based on peak hourly demands rather than daily averages, the Company's capacity
16 requirements and subsequent costs would increase substantially.

17 4. During extreme weather events, when reliable service is most critical for public
18 safety, the disparity between hourly average and peak hourly demand is most
19 pronounced, creating the greatest risk of service disruptions if hourly flow
20 restrictions are imposed.

21 This issue is particularly important to understand because hourly flow restrictions can
22 directly impact UGI Gas's supply management tactics to provide safe, reliable service

1 during critical periods, and addressing these constraints may require significant changes to
2 the UGI Gas procurement strategy with corresponding cost implications for customers.

3
4 **Q. Please explain an hourly flow restriction or limitation and its potential impact on**
5 **service reliability.**

6 A. An hourly flow restriction occurs when an interstate pipeline limits the amount of gas that
7 can be physically delivered to a specific delivery point during each hour of the Gas Day.
8 Under such a restriction, the pipeline typically limits hourly takes to 1/24th (or "ratable")
9 of the daily scheduled quantity. If a distribution company like UGI Gas is unable to limit
10 its takes to this 1/24th hourly rate, the pipeline may:

- 11 1. Physically curtail gas flow to the restricted delivery point;
- 12 2. Impose significant penalties for unauthorized overruns; or
- 13 3. Require the shipper to correct the imbalance immediately, which may not be
14 operationally feasible during high-demand periods.

15 To illustrate the magnitude of this impact: if a delivery point has an average daily demand
16 of 48,000 Dth (2,000 Dth per hour on average), but experiences a peak hourly demand of
17 2,600 Dth during morning hours (30% above the hourly average), an hourly flow restriction
18 would create a supply shortfall of 600 Dth during that critical hour. Projected across a full
19 day, this would require procuring an additional 14,400 Dth of daily capacity to ensure the
20 peak hour demand can be met within the hourly restriction parameters. These restrictions
21 are particularly problematic during cold weather events when customer demand patterns
22 are least likely to conform to the 1/24th hourly pattern that pipelines require during
23 restrictions, precisely when reliable service is most crucial for public health and safety.

1 **Q. Has UGI Gas been affected by an hourly flow restriction? Please explain in detail.**

2 A. Yes, UGI Gas recently experienced a significant hourly flow restriction event. From
3 February 15-23, 2025, Columbia imposed a "Ratable Takes" restriction on UGI Gas's 72-
4 23 delivery point, as documented in UGI Gas Exhibit JRT-5. This restriction limited UGI
5 Gas to taking no more than 1/24th of its scheduled daily quantities during any given hour.
6 Columbia further restricted the delivery point to "Zero Non-Firm," meaning only primary
7 firm supplies could be used. This combination of restrictions created a significant
8 operational challenge during a period of cold weather and high customer demand. UGI Gas
9 implemented a comprehensive response strategy that included:

- 10 1. Issuing an Operational Flow Order directing any replacement shippers of UGI
11 Gas capacity to deliver their Maximum Daily Quantity to the affected delivery
12 point;
- 13 2. Scheduling all available pipeline capacity and storage to the restricted delivery
14 point;
- 15 3. Calling upon all available delivered supplies with primary firm deliverability;
- 16 4. Strategically dispatching LNG supplies from our peak-shaving facilities to
17 supplement pipeline deliveries during the highest demand hours (typically 6:00-
18 10:00 AM ET); and
- 19 5. Implementing enhanced coordination between UGI Central Gas Control and
20 UGI Energy Services (our LNG service provider) to carefully time supply
21 adjustments and LNG dispatches.

22 Through intensive monitoring of real-time flow rates and system operations, UGI Gas
23 successfully navigated the entire restriction period without physical curtailment or

1 penalties. However, this required extraordinary operational measures and highlighted
2 vulnerability to such restrictions. The availability of the applicable LNG facilities proved
3 critical to managing gas takes from Columbia during peak hours, effectively serving as a
4 buffer between the rigid hourly pipeline constraints and UGI Gas customers' actual
5 consumption patterns. This event illustrates why maintaining diverse supply assets,
6 including peak-shaving capabilities, is essential to reliability and ultimately benefits all
7 customers by ensuring uninterrupted service during operational constraints.

8
9 **Q. How would a broader industry shift toward hourly flow requirements affect UGI**
10 **Gas's supply procurement process and customer costs?**

11 A. A broader shift from daily to hourly supply procurement would fundamentally transform
12 UGI Gas's entire supply procurement strategy, with significant implications for both
13 operations and costs. This transformation would require substantial changes, including but
14 not limited to:

- 15 1. Developing new methodologies to determine peak hourly load rather than peak
16 daily load and, requiring more sophisticated analysis of hourly weather patterns,
17 customer usage profiles, and system dynamics;
- 18 2. Reassessing all non-Choice transportation customer contracts to create new
19 billing metrics for Maximum Hourly Quantity ("MHQ") or Hourly Firm
20 Requirement ("HFR") instead of the current daily metrics;
- 21 3. Redesigning the Choice Daily Delivery Requirement ("DDR") methodology to
22 account for hourly load requirements, affecting both NGSs' delivery
23 obligations and UGI Gas's asset assignments;

- 1 4. Evaluating and potentially upgrading all pipeline interconnection points to
- 2 ensure they can accommodate peak hourly design flows;
- 3 5. Retraining personnel, renegotiating supply contracts, and reconfiguring internal
- 4 systems to operate in an hourly rather than daily paradigm; and
- 5 6. Procuring substantial additional firm capacity to meet peak hourly demands.

6 To quantify the potential impact: applying a conservative 30% differential between average
7 hourly flow and peak hourly flow for our Core Market (PGC-1 and Choice customers),
8 UGI Gas’s capacity requirements would increase from approximately 1,196 MDth to 1,555
9 MDth – an increase of over 350,000 Dth per day. This represents a nearly 30% increase in
10 required capacity procurement.

11 The cost implications of this additional capacity would be substantial. Based on
12 current capacity rates and market conditions, this could represent tens of millions of dollars
13 in additional annual costs that would ultimately be reflected in customer rates.
14 Furthermore, this capacity would be underutilized outside of peak hours, creating potential
15 inefficiencies in the supply portfolio.

16
17 **Q. Based on your experience with hourly flow restrictions, what planning change**
18 **considerations do you have for future UGI Gas supply planning?**

19 A. Based on the Company’s experience with hourly flow restrictions and industry trends, the
20 following enhancements to UGI Gas's supply planning approach are being considered:

- 21 1. Incorporate hourly flow risk assessment into the annual capacity planning
- 22 process, identifying delivery points most vulnerable to restrictions and
- 23 developing specific mitigation plans for each;

- 1 2. Continue to maintain and potentially expand the UGI Gas supply portfolio of
2 peak-shaving assets, including LNG facilities, which provide essential
3 flexibility during hourly flow restrictions;
- 4 3. Consider the value of hourly flow management capabilities when evaluating
5 RFP responses and new supply contracts, potentially assigning additional value
6 to resources that offer enhanced hourly flexibility; and
- 7 4. Work with transportation customers and their suppliers to ensure they
8 understand the implications of hourly flow restrictions and have appropriate
9 contingency plans in place.

10 These considerations aim to balance reliability requirements with cost-
11 effectiveness. While shifting entirely to an hourly procurement model would significantly
12 increase costs, targeted enhancements to the current approach will improve UGI Gas's
13 ability to manage hourly flow restrictions without unnecessary rate impacts and prepare
14 UGI for what is likely to become industry standard in the future.

15 As the Company implements actions related to these considerations, UGI Gas will
16 continue to report on their effectiveness and any additional measures that may be warranted
17 to address this evolving operational challenge.

18

19 **XI. Capacity Planning and Supplier Warranties**

20 **Q. Please describe the function of UGI Gas as Capacity Planner.**

21 A. UGI Gas, as Capacity Planner, is responsible for securing adequate, reliable natural gas
22 supplies to satisfy customer demand requirements in accordance with Chapter 22 of Title
23 66 of the Pennsylvania Public Utility Code. This responsibility is central to the Company's

1 obligation as a natural gas distribution company (“NGDC”) and is evaluated annually as
2 part of UGI Gas’s Section 1307(f) Purchased Gas Cost proceedings.

3 The outcome of the Company’s capacity planning efforts is a strategically
4 diversified supply portfolio that combines various assets and services—including pipeline
5 transportation contracts, storage contracts, peaking services, and delivered supply
6 arrangements—designed to reliably meet the demand requirements of the entire UGI Gas
7 service territory throughout the year, including during extreme weather events.

8 For most customers, including all residential and small commercial users as well as Rate
9 DS transportation customers, UGI Gas serves as the Capacity Planner. However, the UGI
10 Gas tariff provides that certain larger transportation customers, specifically Rate LFD and
11 Rate XD customers, may elect to use either UGI Gas or an alternate supplier (typically an
12 NGS) for capacity planning functions.

13 As shown in Attachment 14-1 of Book 1, alternate suppliers are expected to provide
14 848,207 Dth as part of UGI Gas’s peak day supply portfolio. This represents
15 approximately 36% of the Company’s total projected firm peak day demand. This
16 substantial portion of the Company’s supply requirements comes from capacity that UGI
17 Gas does not directly control but must rely upon to maintain system reliability. Without
18 this supply component, UGI Gas could not be able to serve all customers reliably under
19 peak day conditions, making the performance of these alternate Capacity Planners critical
20 to overall system reliability.

1 **Q. Please explain why UGI Gas does not provide the Capacity Planning function for**
2 **certain Rate LFD and Rate XD customers and the challenges this creates.**

3 A. Under UGI Gas's Commission-approved tariff, Rate LFD and Rate XD customers have the
4 option to elect UGI Gas capacity on an annual basis or to arrange their own capacity
5 planning through an alternate supplier. This structure was originally developed to provide
6 these customers with flexibility and potential cost advantages by allowing them to leverage
7 their unique usage patterns and market relationships.

8 When a customer elects UGI Gas capacity, UGI Gas incorporates their expected
9 demand—represented by their Daily Firm Requirement (DFR)—into the overall supply
10 requirements. The Company then attempts to secure appropriate supply assets to serve this
11 demand alongside its other firm service obligations through the RFP process.

12 However, this annual election process creates significant planning challenges for UGI Gas
13 for several reasons:

- 14
- 15 1. **Timing Mismatch:** Pipeline capacity and other supply assets typically require
16 multi-year commitments, while customer elections occur annually. This
17 fundamental mismatch creates a planning dilemma.
 - 18 2. **Planning Uncertainty:** If customers switch their capacity election from year to
19 year, UGI Gas faces uncertainty about how much capacity to secure for future
20 periods.
 - 21 3. **Market Exposure:** If multiple customers simultaneously elect UGI Gas capacity
22 after previously using alternate suppliers, UGI Gas may need to quickly secure

1 substantial additional capacity in a potentially constrained market at premium
2 prices.

3 4. Stranded Asset Risk: Conversely, if customers switch away from UGI Gas
4 capacity after UGI Gas has secured long-term assets to serve them, UGI Gas
5 may be left with excess capacity that must be released or sold into the market,
6 potentially at a loss.

7 These challenges have become more pronounced as UGI Gas has evolved toward a five-
8 year planning horizon pursuant to the Settlement at Docket No. R-2024-3048828. The
9 annual capacity election process is increasingly in conflict with the Company's longer-
10 term planning approach, creating potential reliability and cost risks for all customers.

11

12 **Q. Can you quantify the potential impact of this annual election process on UGI Gas's**
13 **capacity planning?**

14 A. Yes. The potential impact is substantial and directly affects UGI Gas's ability to efficiently
15 secure capacity for all customers. Based on UGI Gas's current customer base, if all Rate
16 LFD customers who currently use alternate Capacity Planners were to simultaneously elect
17 UGI Gas capacity for the upcoming winter (which is permissible under the current UGI
18 Gas tariff), UGI Gas would suddenly need to acquire over 92,000 Dth per day of additional
19 firm supply assets.

20 To put this in perspective, 92,000 Dth per day represents:

- 21 1. Approximately 4% of the Company's total projected firm peak day demand;
22 2. More than five times UGI Gas's current projected capacity shortfall for the
23 2025-26 winter (17,963 Dth); and

1 3. A significant portion of capacity that may not be readily available in the
2 market without substantial lead time or premium pricing.

3 Conversely, if customers currently using UGI Gas capacity were to switch to alternate
4 Capacity Planners, UGI Gas could be forced to release or sell capacity into a potentially
5 oversupplied market at unfavorable terms. This capacity "churn" creates cost inefficiencies
6 that ultimately affect all customers.

7 The magnitude of this exposure illustrates why the current annual election
8 framework has become increasingly problematic as UGI Gas implements a more strategic,
9 longer-term approach to capacity planning. The potential for significant year-to-year
10 swings in capacity requirements is fundamentally inconsistent with the stability and
11 foresight required for prudent long-term capacity planning.

12
13 **Q. What mechanisms does UGI Gas currently have to ensure that alternate Capacity**
14 **Planners have sufficient reliable supply resources to satisfy their customers' demand?**

15 A. Currently, UGI Gas does not have regular, systematic visibility into the capacity
16 arrangements secured by alternate Capacity Planners. UGI Gas is not a party to the specific
17 contractual relationships between transportation customers and their suppliers or agents
18 who perform the Capacity Planning function.

19 Historically, UGI Gas has only implemented verification measures during
20 operational emergencies or pipeline disruptions. For example, in 2019, when Texas Eastern
21 voluntarily reduced system pressure due to operational risks (as detailed in UGI Gas
22 Statement No. 2 at Docket No. R-2020-3019680), the Company issued Supplier Warranties
23 to verify that alternate Capacity Planners had sufficient assets to serve their customers

1 during the constraint. These Supplier Warranties required alternate Capacity Planners to
2 certify one of the following:

- 3 1. They possessed sufficient primary firm assets to serve their customers;
- 4 2. They had insufficient assets but would acquire adequate resources
5 independently; or
- 6 3. They had insufficient assets and requested UGI Gas's assistance in securing
7 resources.

8 For the second and third scenarios, UGI Gas reserved the right to notify the affected
9 customers that their Capacity Planner had insufficient resources, as a precautionary
10 measure in case demand reductions became necessary.

11 While this reactive approach has helped manage specific emergency situations, it does not
12 provide the proactive assurance needed in today's increasingly constrained pipeline
13 capacity environment. The lack of regular verification creates a significant "blind spot" in
14 the Company's overall system reliability planning, particularly as the Company works to
15 secure adequate capacity for the next five years.

16
17 **Q. Please explain what is meant by a "Supplier Warranty" and how it helps address**
18 **capacity planning concerns.**

19 A. A Supplier Warranty is a formal verification mechanism through which UGI Gas requests
20 and receives assurance that an alternate Capacity Planner—whether a customer or an
21 NGS—has secured sufficient primary firm gas supply assets to reliably serve its applicable
22 customers under design day conditions. The Supplier Warranty process typically includes:

- 1 1. A formal request for information regarding the specific primary firm assets
2 secured by the alternate Capacity Planner;
- 3 2. Documentation of transportation contracts, storage arrangements, peaking
4 assets, or delivered supply agreements that will be used to serve the
5 customer;
- 6 3. Verification that these assets have primary firm delivery rights to UGI Gas's
7 system at the appropriate delivery points;
- 8 4. Confirmation that the quantity of these assets is sufficient to meet the
9 customer's full contractual entitlement (DFR or MDQ); and
- 10 5. Identification of any capacity shortfalls that need to be addressed before the
11 winter season.

12 This process serves several important functions:

- 13 • It provides transparency into a critical component of the UGI Gas overall
14 system reliability;
- 15 • It identifies potential supply gaps before they become operational emergencies;
- 16 • It allows for corrective action before the winter heating season begins; and
- 17 • It helps ensure all customers on the UGI Gas system have equitable access to
18 reliable service during peak demand periods.

19 When implemented proactively, rather than just during emergencies, Supplier Warranties
20 function as a prudent risk management tool that complements the Company's overall
21 capacity planning process and helps ensure system-wide reliability.

22

1 **Q. What is the annual UGI Gas capacity election process, and why does this process**
2 **cause concern for UGI Gas?**

3 A. By March 15th of each year, eligible Rate LFD and Rate XD customers must notify UGI
4 Gas whether they will choose to elect UGI Gas capacity or third-party capacity for the
5 following gas year. This annual election process creates several significant concerns:

6 First, for Rate XD customers, there is only a fixed amount of UGI Gas capacity
7 available, which is currently fully subscribed. Additional capacity only becomes available
8 if existing capacity holders relinquish their allocations. This creates a cap on available
9 capacity that may not align with changing customer needs.

10 Second, and more fundamentally, the annual election timeline is incompatible with
11 UGI Gas's five-year planning horizon established pursuant to the Settlement at Docket No.
12 R-2024-3048828. This Settlement recognized the value of longer-term planning to secure
13 reliable, cost-effective capacity in an increasingly constrained market. However, the annual
14 election process undermines this approach by introducing significant year-to-year
15 uncertainty.

16 Consider a scenario where Rate LFD customers currently using alternate Capacity
17 Planners elect UGI Gas capacity for the upcoming winter. UGI Gas would need to secure
18 over 92,000 Dth per day of additional capacity on short notice. If these same customers
19 then reverted to alternate Capacity Planners the following year, UGI Gas would have
20 excess capacity that might need to be sold at a loss. This annual cycle creates particular
21 challenges because:

- 22 1. The interstate pipeline capacity market typically operates on multi-year
23 commitments;

- 1 2. New pipeline capacity projects can require 3-5 years (or longer) of
- 2 development;
- 3 3. Capacity released on short notice often commands premium pricing; and
- 4 4. Capacity released into the market may sell below cost, creating stranded
- 5 costs.

6 These dynamics create unnecessary cost volatility and reliability risks that ultimately affect

7 all customers, not just those making the elections.

8

9 **Q. Is UGI Gas recommending any changes to the Capacity Planning function?**

10 A. Yes, UGI Gas is recommending a two-pronged approach to address the challenges in the

11 current Capacity Planning framework.

12 First, UGI Gas proposes to initiate a comprehensive assessment of the capacity

13 planning relationship between UGI Gas and alternate Capacity Planners. This will include:

- 14 1. Conducting detailed surveys with existing alternate Capacity Planners, both
- 15 customers and NGSs, to gather information about their supply asset
- 16 portfolios;
- 17 2. Holding focused discussions with these stakeholders to evaluate potential
- 18 modifications to the capacity election process that would better align with
- 19 our five-year planning horizon;
- 20 3. Exploring options such as longer election terms, capacity commitment
- 21 requirements, or modified notice provisions that would provide greater
- 22 planning stability while maintaining customer flexibility; and

- 1 4. Developing potential tariff modifications based on this stakeholder input for
2 consideration in a future rate proceeding.

3 Second, UGI Gas proposes to implement an annual Supplier Warranty process as a
4 proactive reliability measure. This process would:

- 5 1. Formalize the verification of alternate Capacity Planners' supply resources
6 before each winter season;
7 2. Provide sufficient lead time to address any identified supply deficiencies;
8 3. Validate the 848,207 Dth of alternate supplier capacity shown in
9 Attachment 14-1 that is critical to the UGI Gas overall peak day reliability;
10 and
11 4. Create transparency regarding this substantial portion of our peak day
12 supply requirements.

13 The Company believes these measures represent a balanced approach that respects
14 customer choice while enhancing system reliability. Rather than immediately proposing
15 specific tariff changes, UGI Gas is recommending a collaborative process to develop
16 solutions that address the timing mismatch between annual elections and the Company's
17 five-year planning horizon. The Company will provide the results of this collaborative
18 process in its 2026 annual 1307(f) PGC proceeding.

19
20 **Q. How would the proposed Supplier Warranty process benefit UGI Gas customers and**
21 **enhance system reliability?**

22 A. The proposed annual Supplier Warranty process would provide several significant benefits
23 to all UGI Gas customers and enhance overall system reliability:

- 1 1. Proactive Risk Management: By identifying potential capacity shortfalls
2 before the winter heating season, the Company can address issues
3 proactively rather than during peak demand periods when options are
4 limited and costs are highest.
- 5 2. System-Wide Reliability: All customers benefit from a more reliable
6 distribution system. When all suppliers—whether UGI Gas or alternate
7 Capacity Planners—have secured adequate resources, the entire system
8 operates more reliably during extreme weather events.
- 9 3. Equitable Resource Planning: The process helps ensure that all customers,
10 regardless of their supplier, have equitable access to reliable service and that
11 no customer group is inadvertently subsidizing another through
12 disproportionate reliability investments.
- 13 4. Transparency: The process provides greater visibility into a critical
14 component of the UGI Gas supply portfolio that currently lacks systematic
15 verification.
- 16 5. Emergency Preparedness: By validating capacity arrangements before
17 emergencies occur, UGI Gas can develop more effective contingency plans
18 that account for actual supply resources rather than assumptions.
- 19 6. Cost Stabilization: Addressing capacity gaps systematically rather than
20 during emergency conditions generally results in more cost-effective
21 solutions.
- 22 7. Regulatory Compliance: The process supports the obligation under Section
23 1317 of the Public Utility Code to pursue a least-cost procurement policy

UGI GAS EXHIBIT JRT-1

(Resume and Educational Background)

JESSE R. TYAHLA

DIRECTOR – FP&A and Strategic Modeling

Work Experience

2025 – Present	Director, FP&A and Strategic Modeling UGI Corporation, King of Prussia, Pa
2020 – 2025	Director, Energy Supply & Planning UGI Utilities, Inc., Denver, Pa
2018 – 2020	Director, Supply Origination & Business Development UGI Energy Services, LLC, Wyomissing, Pa
2014 – 2018	Manager, Gas Supply Trading UGI Energy Services, LLC, Wyomissing, Pa
2012 – 2014	Analyst, Supply & Asset Optimization UGI Energy Services, LLC, Wyomissing, Pa
2010 – 2012	Supply Analyst UGI Utilities, Inc., Reading, Pa
2008 – 2010	Rates Analyst UGI Utilities, Inc., Reading, Pa

Education

MBA, Lehigh University, Bethlehem, Pa.
BS, Economics, Pennsylvania State University, State College, Pa.

Previous Testimony

UGI 2024 Base Rate Case Proceeding	Docket No. R-2024-3052716
UGI 2024 1307(f) Proceeding	Docket No. R-2024-3048828
UGI 2023 Commodity and Purchased Gas Proceeding	MD PSC Case No. 9516(f)
UGI 2023 1307(f) Proceeding	Docket No. R-2023-3040290
UGI 2022 Commodity and Purchased Gas Proceeding	MD PSC Case No. 9516(e)
UGI 2022 1307(f) Proceeding	Docket No. R-2022-3032242
UGI 2021 Commodity and Purchased Gas Proceeding	MD PSC Case No. 9516(d)
UGI 2021 1307(f) Proceeding	Docket No. R-2021-3025652

UGI GAS EXHIBIT JRT-2
(Summary of Contract Renewals)

Summary of Contract Renewals

Contract	MDQ	Effective Date	Term End Date	Notice Date	Demand Rates (\$/Dth)	Term Extension	Extension Process
Columbia FSS - 79028	126,473	11/1/2004	3/31/2025	9/30/2024	\$265**	5 Years	Extension notice provided
Columbia SST - 79133	126,473	11/1/2004	3/31/2025	9/30/2024	\$265**	5 Years	Extension notice provided
Columbia FTS - 229154	7,750	11/1/2004	3/31/2025	9/30/2024	\$265**	5 Years	Extension notice provided
EGTS FT - 700117	2,000	11/1/1998	3/31/2025	3/31/2024	\$72	5 Years	Extension notice provided
EGTS GSS - 300126*	8,667	11/1/1998	3/31/2025	3/31/2023	\$53	5 Years	Extension notice provided
EGTS GSS - 300225	2,000	11/1/1998	3/31/2025	3/31/2023	\$53	5 Years	Extension notice provided
Texas Eastern CDS - 800239	25,000	6/1/1993	10/31/2025	10/31/2024	\$294	1 Year	Automatic evergreen rollover
Texas Eastern CDS - 800397	41,000	11/1/1993	10/31/2025	10/31/2024	\$294	1 Year	Automatic evergreen rollover
Texas Eastern CDS - 820019	10,000	11/1/2000	10/31/2025	10/31/2024	\$184	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800468	10,000	11/1/1995	10/31/2026	10/31/2024	\$181	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 830067	10,000	12/1/1999	10/31/2026	10/31/2024	\$181	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800504	4,000	11/1/1995	10/31/2025	10/31/2024	\$179	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800373	20,000	11/1/1994	10/31/2026	10/31/2024	\$181	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800240	25,000	6/1/1993	10/31/2025	10/31/2024	\$288	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800394	32,475	11/1/1993	10/31/2025	10/31/2024	\$288	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 910181	12,000	11/1/2004	10/31/2025	10/31/2024	\$184	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 910417	11,713	11/1/2003	10/31/2025	10/31/2024	\$181	1 Year	Automatic evergreen rollover
Texas Eastern FTS-5 – 330910	6,667	6/1/1993	3/31/2027	3/31/2025	\$87	1 Year	Automatic evergreen rollover
Texas Eastern CDS - 800376	8,068	10/1/1993	10/31/2026	10/31/2024	\$304	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800404	1,136	11/1/1994	10/31/2025	10/31/2024	\$298	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 830060	4,000	3/24/1999	11/30/2026	11/30/2024	\$155	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 911153	3,300	11/1/2014	10/31/2025	10/31/2024	\$85	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 8983450	15,003	4/1/2020	3/31/2025	None	\$208	1 Year	Automatic evergreen rollover
Texas Eastern SS-1 - 400190	7,659	5/1/1994	4/30/2027	4/30/2025	\$125	1 Year	Automatic evergreen rollover
Transco FT - 1002594	5,072	2/1/1992	3/31/2028	3/31/2025	\$282**	1 Year	Automatic evergreen rollover
Transco FT - 1002595	2,081	4/10/1990	3/31/2028	3/31/2025	\$282**	1 Year	Automatic evergreen rollover
Transco FT-PS - 1005004	1,346	8/1/1991	3/31/2028	3/31/2025	\$128**	1 Year	Automatic evergreen rollover
Transco ESS - 9162496	10,000	11/1/1993	10/31/2025	4/30/2025	\$30**	1 Year	Automatic evergreen rollover
Transco FT - 9180223	12,279	12/1/2015	7/31/2027	7/31/2024	\$282**	1 Year	Automatic evergreen rollover
Transco FT-PS - 1004999	3,416	8/1/1991	3/31/2028	3/31/2025	\$128**	1 Year	Automatic evergreen rollover
Transco LSS - 1000796	7,518	10/1/1993	3/31/2026	3/31/2025	\$121**	1 Year	Automatic evergreen rollover
Transco FT - 1021107	1,500	11/1/1997	3/31/2025	9/30/2024	\$24**	1 Year	Automatic evergreen rollover
Transco FT- PS - 1005005	311	8/1/1991	7/31/2027	7/31/2024	\$128**	1 Year	Extension notice provided
Transco FT - 1003692	10,712	2/1/1992	3/31/2028	3/31/2025	\$282**	1 Year	Extension notice provided
Transco FT - 1006503	4,566	10/1/1993	10/31/2025	10/31/2024	\$290**	1 Year	Extension notice provided
Transco FT - 1012119	828	11/16/1995	3/31/2026	3/31/2025	\$282**	1 Year	Extension notice provided
Transco LG-A - 1000783	1,035	11/1/1974	3/31/2025	9/30/2024	\$103**	1 Year	Extension notice provided
Tennessee FT-G - 62498	831	9/1/1993	10/31/2025	10/31/2024	\$152	5 Years	Extension notice provided
Tennessee FT-G - 62499	2,054	9/1/1993	10/31/2025	10/31/2024	\$52	5 Years	Extension notice provided
Tennessee FT-A – 362539	3,183	11/1/2020	10/31/2026	10/31/2025	\$52	5 Years	Extension notice provided
UGI Energy Services - Peaking - UGIU-P-1012	23,632	11/1/2016	3/31/2026	3/31/2025	\$153	5 Years	Extension notice provided
UGI Energy Services - Peaking - PNG-P-1003	21,772	11/1/2016	3/31/2026	3/31/2025	\$132	5 Years	Extension notice provided
Supplier J – Local Production	800	11/1/2020	10/31/2024	7/31/2024	N/A	1 Year	Extension notice provided
Supplier M – Local Production	1,680	7/1/2023	3/31/2025	None	N/A	1 Year	Extension notice provided

* EGTS Contracts 300126 and 300224 were consolidated at time of renewal.

** Current pipeline rates for Columbia and Transco are subject to change and refund, pending their respective open Section 4 rate cases.

UGI GAS EXHIBIT JRT-3
(Summary of Future Contract Renewals)

Summary of Future Contract Renewals

Contract	MDQ	Effective Date	Term End Date	Notice Date	Demand Rates (\$/Dth)	Term Extension	Extension Process	Contract Benefit
EGTS FT - 200796	2,000	1/1/2005	3/31/2026	3/31/2025	\$72	2 Years	Extension notice provided	1, 2, 4
Supplier J – Local Production	800	10/31/2020	10/31/2025	7/31/2025	N/A	1 Year	Extension notice to be provided	1, 5
Texas Eastern CDS - 800239	25,000	6/1/1993	10/31/2026	10/31/2025	\$280	1 Year	Automatic evergreen rollover	2, 3, 4
Texas Eastern CDS - 800397	41,000	11/1/1993	10/31/2026	10/31/2025	\$280	1 Year	Automatic evergreen rollover	2, 3, 4
Texas Eastern CDS - 820019	10,000	11/1/2000	10/31/2026	10/31/2025	\$216	1 Year	Automatic evergreen rollover	2, 3, 4
Texas Eastern FT-1 - 800468	10,000	11/1/1995	10/31/2027	10/31/2025	\$181	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 830067	10,000	12/1/1999	10/31/2027	10/31/2025	\$181	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 800504	4,000	11/1/1995	10/31/2026	10/31/2025	\$179	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 800373	20,000	11/1/1994	10/31/2027	10/31/2025	\$181	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 800240	25,000	6/1/1993	10/31/2026	10/31/2025	\$288	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 800394	32,475	11/1/1993	10/31/2026	10/31/2025	\$288	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 910181	12,000	11/1/2004	10/31/2026	10/31/2025	\$245	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 910417	11,713	11/1/2003	10/31/2026	10/31/2025	\$181	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FTS-5 – 330910	6,667	6/1/1993	3/31/2028	3/31/2026	\$87	1 Year	Automatic evergreen rollover	1, 2, 4
Texas Eastern FT-1 - 911580	5,880	11/1/1994	4/15/2026	4/15/2025	\$181	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern CDS - 800376	8,068	10/1/1993	10/31/2027	10/31/2025	\$294	1 Year	Automatic evergreen rollover	2, 3, 4
Texas Eastern FT-1 - 800404	1,136	11/1/1994	10/31/2026	10/31/2025	\$298	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 830060	4,000	3/24/1999	11/30/2027	11/30/2025	\$155	1 Year	Automatic evergreen rollover	1, 2, 4
Texas Eastern FT-1 - 911153	3,300	11/1/2014	10/31/2026	10/31/2025	\$85	1 Year	Automatic evergreen rollover	1, 2, 4
Texas Eastern SS-1 - 400190	7,659	5/1/1994	4/30/2027	4/30/2025	\$125	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT - 1002594	5,072	2/1/1992	3/31/2029	3/31/2026	\$282**	1 Year	Automatic evergreen rollover	2, 4
Transco FT - 1002595	2,081	4/10/1990	3/31/2029	3/31/2026	\$282**	1 Year	Automatic evergreen rollover	2, 4
Transco FT - 1013596	22,770	10/1/1996	3/31/2027	3/31/2026	\$68**	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT-PS - 1005004	1,346	8/1/1991	3/31/2029	3/31/2026	\$128**	1 Year	Automatic evergreen rollover	1, 2, 4
Transco ESS - 9162496	83,847	11/1/1993	10/31/2026	4/30/2026	\$30**	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT - 9180223	12,279	12/1/2015	7/31/2028	7/31/2025	\$282**	1 Year	Automatic evergreen rollover	2, 4
Transco FT-PS - 1004999	3,416	8/1/1991	3/31/2029	3/31/2026	\$128**	1 Year	Automatic evergreen rollover	1, 2, 4
Transco LSS - 1000796	827,053	10/1/1993	3/31/2027	3/31/2026	\$121**	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT - 1021107	1,500	11/1/1997	3/31/2026	9/30/2025	\$24**	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT- PS - 1005005	311	8/1/1991	7/31/2028	7/31/2025	\$128**	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT - 1003692	10,712	2/1/1992	3/31/2029	3/31/2026	\$282**	1 Year	Automatic evergreen rollover	2, 4
Transco FT - 1006503	4,566	10/1/1993	10/31/2026	10/31/2025	\$199**	1 Year	Automatic evergreen rollover	2, 4
Transco FT - 1012119	828	11/16/1995	3/31/2027	3/31/2026	\$282**	1 Year	Automatic evergreen rollover	2, 4
Transco LG-A - 1000783	4,140	11/1/1974	3/31/2026	9/30/2025	\$103**	1 Year	Automatic evergreen rollover	1, 2, 4
Tennessee FT-A – 362539	3,183	11/1/2020	10/31/2026	10/31/2025	\$52	1 Year	Automatic evergreen rollover	1, 2, 4

Contract Benefits Key:
1 - Low Contract Cost*
2 - Provides Service Flexibility
3 - Is Callable at No-Notice
4 - Hard to replace, fully subscribed capacity
5 - Local Production/Supply Diversity

*Threshold established at the Weighted Average Cost of Demand for DS customers as of June 1, 2025.

** Current pipeline rates for Columbia and Transco are subject to change and refund, pending their respective open Section 4 rate cases.

UGI GAS EXHIBIT JRT-4

(Summary of AMA Responses)

Summary of Transco AMA RFP Responses

	Supplier A	Supplier B	Supplier C
Delivery Pipe	Transco	Transco	Transco
Term	1 year	1 year	1 year
Total Days of Service	365	365	365
Daily Volume Offered	10,000	10,000	10,000
Total AMA Capacity	3,650,000	3,650,000	3,650,000
UGI Call Option Available	Yes	Yes	Yes
ROFR Offered	No	No	No
Total Fee	\$ [REDACTED]	\$ [REDACTED]	\$ [REDACTED]
Total Cost per Dth per Day	\$ [REDACTED]	\$ [REDACTED]	\$ [REDACTED]

Summary of TETCO AMA RFP Responses

	Supplier A	Supplier B
Delivery Pipe	TETCO	TETCO
Term	1 year	1 year
Total Days of Service	365	365
Daily Volume Offered	20,000	20,000
Total AMA Capacity	7,300,000	7,300,000
UGI Call Option Available	Yes	Yes
ROFR Offered	No	No
Total Fee	\$ [REDACTED]	\$ [REDACTED]
Total Cost per Dth per Day	\$ [REDACTED]	\$ [REDACTED]

Summary of EGTS AMA RFP Responses

	Supplier A	UGIES	Supplier B
Storage Asset	EGTS	EGTS	EGTS
Term	3 Years	3 Years	3 Years
Total Days of Service	1,096	1,096	1,096
Daily Withdrawal Volume	56,667	56,667	56,667
Storage Contract Quantity	3,400,000	3,400,000	3,400,000
UGI Call Option Available	Yes	Yes	Yes
Total Fee	\$ [REDACTED]	\$ [REDACTED]	\$ [REDACTED]
Total Cost per Dth per Day	\$ [REDACTED]	\$ [REDACTED]	\$ [REDACTED]

UGI GAS EXHIBIT JRT-5

(TCO FM Critical Notice)

TSP Name	Columbia Gas Transmission, LLC	TSP	054748041	Date		Time	
Notice ID	25926835	Notice Type Description:	Force Majeure	Post	02/10/25	3:13:00 PM	
		Notice Stat Desc:	Initiate	Notice Effective	02/10/25	12:00:00 AM	
		Prior Notice:		Notice End	03/10/25	12:00:00 AM	
		Critical:	Y	Response			
		Reqrd Rsp Desc:	No Response Required				

Subject: Force Majeure: Line 1804

Author: Tyler King

Notice Text

Columbia Gas Transmission, LLC (TCO) notifies customers of the need for an immediate pressure reduction on Line 1804 east of the Waynesburg Compressor Station in Pennsylvania. This necessary measure is being taken due to anomalies discovered from recent in-line inspections of the pipeline performed pursuant to requirements by the Pipeline and Hazardous Materials Safety Administration (PHMSA), and TCO's integrity program, to maintain the safety and reliability of the system.

These results could not be prevented or overcome by the due diligence of TCO and require expedient action to maintain the safety and reliability of the system. Consequently, pursuant to Section 15 of the General Terms and Conditions of TCO's FERC Gas Tariff, TCO is declaring a Force Majeure effective Gas Day February 10, 2025.

Based on current operating conditions, there is no commercial impact related to the necessary pressure reduction at this time.

However, the location of the necessary pressure reduction results in decreased throughput across Line 1804, which is used to transport supply from western receipts in Operating Area 8 to eastern markets in Market Areas 26, 27, and 35 (Operating Area 8), and all Market Areas in Operating Area 4. Due to this decreased throughput, coupled with forecasted colder temperatures beginning Wednesday, February 12, 2025, TCO anticipates the following commercial restrictions may become necessary:

- - OPT-30 & OPT-60 availability through the Artemas MA25 internal constraint (ARTEMAS)
- - OPT-60 availability through the Downingtown East MA24 internal constraint (DOWNEAST)
- - Ratable Take requirements in Market Areas 22, 23, 24, 28
- - Storage and Transport Critical Days in Market Areas 26, 27, 35 and all Market Areas within Operating Area 4
- - 634545 - Gilbert - Zero Non-Firm
- - 636563 - GAE - AES LAKE LYNN - Zero Non-Firm
- - 72-23 - UGI CORP-23 - Zero Non-Firm
- - Other non-firm restrictions, as operationally necessary

TCO will provide updates as additional information becomes available. Please continue to monitor critical notices, including the Daily Capacity Posting, for any adjustments related to this Force Majeure.

Reservation charge credits (RCCs) will be determined per the process set forth in the General Terms and Conditions, Section 38 of TCO's FERC Gas Tariff ("Tariff"). However, TCO will only issue RCCs if TCO is unable to schedule or deliver primary firm nominated capacity as a result of the Force Majeure for a period greater than ten consecutive days. In the event RCCs are issued as set forth in the Tariff, shippers will receive RCCs based on its 7-day average usage quantity less any scheduled quantities on the contract. By means of this notice, TCO is establishing which specific Gas Days will be included when determining a shipper's 7-day average usage quantity pursuant to the provisions in the Tariff.

Please contact your Customer Services Representative with any questions.