
Pennsylvania Public
Utility Commission et al.
v.
National Fuel Gas
Distribution Corporation
1307(f)

Call-In Telephonic
Evidentiary Hearing

Docket No.:
R-2024-3045177

Pages 14 - 54

Judge's Chambers
Commonwealth Keystone
Building - Plaza Level
400 North Street
Harrisburg, PA

Wednesday April 3, 2024
Commencing at 10:00 a.m.

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Docket No. R-2024-3045177

Hearing Date: April 3, 2024

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TESTIMONY OF
CHRISTOPHER A. CEJ
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024-3045177

DIRECT TESTIMONY OF CHRISTOPHER A. CEJ
R-2024-3045177

1 Q. Please state your name and business address.

2 A. My name is Christopher A. Cej, and my business address
3 is 6363 Main Street, Williamsville, New York 14221.

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

5 A. I am employed by National Fuel Gas Distribution
6 Corporation ("Distribution" or the "Company") as
7 General Manager of the Gas Supply Administration
8 Department.

9 Q. What are your duties as General Manager of the Gas
10 Supply Administration Department?

11 A. I am responsible for overseeing the Gas Procurement,
12 Gas Accounting, Gas Planning, and Transportation
13 Services functional areas. I report directly to the
14 Vice President.

15 Q. Please summarize your education and work experience.

16 A. I received a Bachelor of Science Degree in Civil
17 Engineering from the State University of New York at
18 Buffalo in 1991. I was hired by Distribution in
19 February 1992 as a Management Trainee in the Risk
20 Management-Environmental Affairs Department. I
21 received my Certified Hazardous Materials Manager
22 ("CHMM") certification through the Institute of
23 Hazardous Materials Management. In 2000 I transferred
24 to the Energy Services Department where I received my

DIRECT TESTIMONY OF CHRISTOPHER A. CEJ
R-2024-3045177

1 certification as a Chartered Industrial Gas Consultant
2 through the Gas Research Institute. In October 2004 I
3 was transferred to Gas Supply Administration. I was
4 promoted to my current position in February 2018.

5 Q. What is the subject of your testimony?

6 A. I am testifying to PGC Exhibit Nos. 4, 8, 9 and 32.

7 Q. Were PGC Exhibit Nos. 4, 8, 9, and 32 prepared under
8 your supervision and direction?

9 A. Yes, they were.

10 Q. Please explain PGC Exhibit No. 4.

11 A. PGC Exhibit No. 4 is Distribution's response to the
12 Pennsylvania Public Utility Commission's ("PAPUC")
13 filing requirement at 52 Pa. Code § 53.64(c)(1), which
14 requires details regarding contracts under which
15 Distribution purchases supplies of gas and
16 renegotiations of such contracts. PGC Exhibit No. 4
17 also provides details regarding Distribution's
18 contracts for upstream pipeline transportation and
19 storage services, the design of rates for such
20 services, and recent and pending negotiations of such
21 upstream pipeline contracts. Ms. Lisa Petko and Mr.
22 Marc Cuthbertson will be testifying to the specific
23 elements contained in this Exhibit.

24 Q. Please explain PGC Exhibit No. 8.

DIRECT TESTIMONY OF CHRISTOPHER A. CEJ
R-2024-3045177

1 A. PGC Exhibit No. 8 is Distribution's response to the
2 PAPUC filing requirement at 52 Pa. Code § 53.64(c)(1),
3 which requires details of future procurement, capacity
4 strategies or changes. The Company's recent market
5 demand forecast reflects continued sustained growth
6 over the next few years and suggests the Company may
7 need to acquire additional firm capacity to reliably
8 serve the increasing demand. Ms. Lisa Petko and Mr.
9 Marc Cuthbertson will offer greater detail in their
10 respective testimonies.

11 Q. Please explain PGC Exhibit No. 9.

12 A. PGC Exhibit No. 9 provides monthly summaries of
13 Distribution's capacity release and assignment
14 activities.

15 Q. Please explain PGC Exhibit No. 32.

16 A. PGC Exhibit No. 32 provides monthly summaries of
17 Distribution's supply mix for the period December 1,
18 2020, through November 30, 2021.

19 Q. Are there any other issues about which you wish to
20 testify?

21 A. Yes, I would like to provide an update on the
22 Company's efforts to identify renewable natural gas
23 ("RNG") and responsibly sourced natural gas supply
24 ("CNG") opportunities.

DIRECT TESTIMONY OF CHRISTOPHER A. CEJ
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1 Q. Is the Company pursuing RNG opportunities?

2 A. Yes, the Company continues to pursue and review
3 potential beneficial RNG procurement opportunities to
4 present to the Parties. The Company is focusing on
5 procurement opportunities that support growth of RNG
6 production connected to the Company's system that may
7 enhance system delivery pressure reliability, or RNG
8 production accessible through the Company's portfolio
9 of firm pipeline capacity assets, at a market-based
10 gas price. The Company has discussed potential RNG
11 opportunities with a few counterparties but none of
12 those discussions have evolved into a proposal
13 beneficial to the ratepayer. While the Company has
14 been unable to find such opportunities it will
15 continue to pursue a proposal to present to the
16 Parties that it believes will benefit ratepayers.

17 Q. Is the Company pursuing RNG purchase opportunities
18 that include purchasing the associated environmental
19 attributes?

20 A. Not necessarily. The Company does not intend to pay a
21 premium to acquire the environmental attributes unless
22 the Company is able to offset the premium through sale
23 of the attributes.

DIRECT TESTIMONY OF CHRISTOPHER A. CEJ
R-2024-3045177

1 Q. Is it the Company's intent to review any such
2 proposals with the Parties before proceeding with an
3 executed transaction?

4 A. Yes, as prescribed in the Company's 2022 1307(F)
5 Settlement at Docket No. R-2022-3030235.

6 Q. Has the Company pursued CNG opportunities?

7 A. Similar to RNG, the Company is pursuing beneficial CNG
8 opportunities that include suppliers providing the
9 Company proof of CNG certification. While discussions
10 with CNG suppliers have not materialized into
11 substantive proposals, the Company believes a growing
12 percentage of its traditional gas supply purchases
13 from suppliers under least cost purchasing practices
14 at Appalachian production basin aggregation pools are
15 sourced from CNG certified production wells, located
16 within the basin.

17 Q. Is the Company claiming CNG credit for these
18 purchases?

19 A No. The Company did not receive CNG certification
20 from the suppliers, so it would not claim CNG credit
21 for these purchases.

22 Q. Will the Company continue pursuing CNG supplies and
23 its associated certifications?

DIRECT TESTIMONY OF CHRISTOPHER A. CEJ
R-2024-3045177

- 1 A. Yes. The Company is proposing a CNG pilot program.
- 2 Refer to Mr. Cuthbertson's testimony, Distribution PGC
- 3 Statement No. 3, for detail related to the Company's
- 4 proposal.
- 5 Q. Does this conclude your testimony?
- 6 A. Yes, it does at this time.

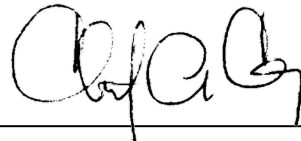
Verification

I, Christopher A. Cej, General Manager, of the Gas Supply Administration Department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 1

Exhibit Nos. 4 (partial), 8 (partial), 9, 32

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

A handwritten signature in black ink, appearing to read 'Cej', written over a horizontal line.

Christopher A. Cej

This 31st day of January, 2024

TESTIMONY OF
MARC T. CUTHBERTSON
IN BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024-3045177

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
R-2024-3045177

1 Q. Please state your name and business address.

2 A. My name is Marc T. Cuthbertson, and my business
3 address is 6363 Main Street, Williamsville, New York
4 14221.

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

6 A. I am employed by National Fuel Gas Distribution
7 Corporation ("Distribution" or the "Company") as a
8 Manager of Procurement & Optimization in the Gas
9 Supply Administration Department ("GSA").

10 Q. What are your duties as Manager of Procurement &
11 Optimization for Distribution?

12 A. I manage in developing and implementing Distribution's
13 Gas Procurement and Gas Planning policies.

14 Q. Please summarize your education and work experience.

15 A. I received a Bachelor of Science Degree in Business
16 Administration from the State University of New York
17 ("SUNY") at Buffalo in 2008. In June 2008, I was hired
18 by Distribution as a Supervisor in GSA working in the
19 Gas Accounting area. In 2010, I was transferred to the
20 Gas & Capacity Procurement area within GSA where my
21 responsibilities included natural gas procurement,
22 asset optimization, and natural gas scheduling. In
23 2023, I was promoted to Manager.

24 Q. What is the subject of your testimony?

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
R-2024-3045177

1 A. I am testifying to PGC Exhibit No. 4 (partial), PGC
2 Exhibit No. 8 (partial), PGC Exhibit No. 9 and PGC
3 Exhibit No. 32.

4 Q. Were PGC Exhibit Nos. 4, 8, 9, and 32 prepared under
5 your supervision and direction?

6 A. Yes, they were.

7 Q. Please explain PGC Exhibit No. 4.

8 A. The portion of PGC Exhibit No. 4 that I am sponsoring
9 begins on page 5, line 18 and ends on page 13, line
10 15. My testimony related to PGC Exhibit No. 4 details
11 the manner in which Distribution used Term (delivery
12 terms greater than one month) and Spot (delivery terms
13 equal to or less than one month) purchase transactions
14 to obtain commitments of firm supply.

15 Consistent with its least-cost purchasing
16 strategy, Distribution utilized the take-or-release
17 flexibility provided in its Term purchase agreements
18 to incorporate lower cost Spot supplies in its winter
19 supply portfolio. Prior to each month and day of the
20 contract term, and accounting for operational
21 conditions at that time, Distribution evaluated its
22 purchase options and elected the best-cost supply
23 option. For any month or day that Term supplies were
24 replaced with lower cost Spot supplies, Distribution

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
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1 maintained the daily call option provided in the Term
2 supply contract. Thus, Distribution's ratepayers
3 realized savings while still being ensured winter
4 supply reliability.

5 As presented in PGC Exhibit No. 4, Ms. Petko
6 describes Distribution's continued effort to realign
7 its capacity portfolio. As a result of these actions,
8 Distribution has been able to maintain and increase
9 its primary access to reliable northeast supplies.
10 Using its upstream transmission assets, Distribution
11 was able to purchase all of its winter 2022-2023
12 supplies at receipt points in the northeast.

13 As Distribution's upstream capacity
14 portfolio evolves, Distribution will continue to
15 evaluate the appropriate gas purchase contracts for
16 Term and Spot supplies from the appropriate supply
17 basins. Distribution's goal remains to achieve cost
18 savings for its customers while maintaining service
19 reliability and price stability.

20 Q. Please explain PGC Exhibit No. 8.

21 A. My testimony for PGC Exhibit No. 8 includes portions
22 of Section II (page 10, line 15 to page 7, line 21 and
23 page 17, line 10 to page 18, line 11) and all of
24 Section III.

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
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1 Section II, Distribution's Least Cost
2 Purchase Strategy, reviews the details of
3 Distribution's Term and Spot purchases.

4 Also described in this section is
5 Distribution's Gas Cost Management Plan ("Plan") and
6 how it is used to mitigate price volatility through
7 price diversity.

8 Q. Could you further explain the Gas Cost Management
9 Plan?

10 A. The Plan (Exhibit MTC-1) lays out in summary form how
11 storage and gas purchase pricing methodologies are
12 used by Distribution to diversify pricing and mitigate
13 gas cost volatility.

14 Section I of the Plan identifies fixed and
15 capped forward pricing measures Distribution will use
16 for purchasing approximately 12% of its forecasted
17 winter (November - March) supply requirements.

18 Section II recognizes that approximately 40%
19 of the winter supplies are withdrawn from storage.

20 Section III notes that approximately 24% of
21 winter and 50% of summer supplies will be priced at a
22 mix of index, NYMEX Settlement plus fixed physical
23 basis, and bid week negotiated cash ("Cash") prices.

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
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1 Section IV takes into account that the
2 remaining supplies (approximately 24% winter and 50%
3 summer) will be procured on a daily basis and will be
4 priced at index and/or Cash prices.

5 The Plan provides for the flexibility to
6 adjust the timing of forward prices based on market
7 fundamentals and unanticipated events.

8 Q. Please describe the changes to the Plan under the
9 settlement at R-2023-3037428.

10 A. Effective April 1st, 2025, the Company has amended its
11 current Plan to incorporate fixed summer price
12 purchases, see Exhibit MTC-2. The Company will execute
13 two forward price transactions for 15%-20% of
14 forecasted summer (April - October) demand
15 requirements and storage fill requirements. The
16 Company will send an RFP for these forward price deals
17 in May 2024 and July 2024 for baseload fixed price
18 deliveries starting on April 1st, 2025 - October 31st,
19 2025. These transactions will follow the Company's
20 least cost gas policy and will be executed in a
21 similar manner to its current fixed price transactions
22 for winter delivery.

23 Q. Has Distribution entered into any Asset Management
24 Arrangements ("AMA") or storage fill agreements?

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
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1 A. Pursuant to a Request for Proposal ("RFP") issued in
2 February 2023, Distribution entered into a storage
3 fill agreement for the 2023 injection season. The
4 Supplier was required to deliver a quantity of gas
5 which would satisfy a portion of Distribution's
6 seasonal injection requirement. In general,
7 Distribution attempts to purchase supplies evenly over
8 the summer injection season in order to diversify
9 inventory costs. In exchange for a gas cost discount,
10 the supplier was provided the ability to choose the
11 days of delivery. The total value of the discount was
12 approximately \$130,000.

13 Q. Are there any other specific issues you would like to
14 highlight regarding gas procurement practices in PGC
15 Exhibit No. 8?

16 A. Yes. I would like to briefly address capacity and
17 basin diversity.

18 The pipeline capacity entitlements discussed
19 in PGC Exhibit No. 8, Section II, Part C, afford
20 Distribution opportunities to purchase gas sourced
21 from the Marcellus, Utica and Mid-continent production
22 basins. Distribution maintains master gas purchase
23 contracts with suppliers that have substantial gas
24 supplies in these production areas and is prepared to

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
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1 purchase gas supplies at receipt point interconnects
2 in these basins. To the extent that older production
3 basins decline, and new basins are developed, this
4 pipeline capacity diversity will ensure Distribution
5 ratepayers will have access to reliable gas supplies
6 in the future.

7 Production from the Marcellus and Utica
8 shale formations continues to grow and now exceeds 35
9 Bcf/day. During the historical year, market area
10 production from these basins represented 100% of
11 Distribution's purchases. These market area purchases,
12 coupled with the revenues associated with releasing
13 the unutilized upstream capacity on a recallable
14 basis, contribute to Distribution's least-cost gas
15 procurement strategy of minimizing ratepayer cost
16 while preserving firm access to established liquid
17 pool points.

18 Distribution continues to rely upon firm
19 access to market area pooling points and paths,
20 including Texas Eastern Transmission's M2 Market area
21 pool, Tennessee Gas Pipeline Company's station 219
22 pool, and the firm paths through production areas
23 along the Texas Eastern and Tennessee pipeline
24 systems. Maintaining firm access to liquid pooling

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
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1 points and paths is an important reliability criteria
2 considered by Distribution when evaluating its
3 capacity portfolio.

4 Q. Please explain PGC Exhibit No. 9.

5 A. PGC Exhibit No. 9 provides monthly summaries of
6 Distribution's capacity release and off-system sale
7 activity during the period December 1, 2022, through
8 November 30, 2023. The total value of all sharable
9 releases during the period was \$1,800,000.

10 Similar to last year, market conditions did
11 not support off-system sales and no margins were
12 generated during the 12-month historic period ending
13 November 30, 2023.

14 Q. Please explain PGC Exhibit No. 32.

15 A. PGC Exhibit No. 32 provides monthly summaries of
16 Distribution's supply mix for the period December 1,
17 2022, through November 30, 2023.

18 Q. Are there any other issues about which you wish to
19 testify?

20 A. Yes, I would like to provide information for a pilot
21 program to procure certified natural gas ("CNG").

22 Q. What is CNG?

23 A. CNG is natural gas that has been evaluated and
24 verified by an independent third-party to have been

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
R-2024-3045177

1 produced with reduced GHG emissions and environmental
2 impacts, beyond current environmental regulations.

3 The purpose of various CNG programs is to incentivize
4 continuous improvement in methane emissions monitoring
5 and abatement by creating an opportunity for producers
6 to differentiate their natural gas production by its
7 methane emissions performance.

8 Q. What are some of the benefits of CNG?

9 A. CNG is a low carbon gas produced from certified wells.
10 There are a number of ways to reduce methane
11 emissions, including reducing leaks from the
12 production, storage, and transportation of natural
13 gas. Certified gas wells can reduce methane emissions
14 up to 80% from traditional wells. CNG provides the
15 same reliability as conventional natural gas and is
16 compatible with all existing natural gas
17 infrastructure.

18 Q. What is the goal of the Company's CNG Pilot Program?

19 A. The Company aims to identify and purchase natural gas
20 from operators who are implementing best practices in
21 the production of natural gas including lowering
22 emissions. The Company also intends to quantify CO₂e
23 abated by measuring the methane intensity of the CNG

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
R-2024-3045177

1 versus the intensity of the traditionally extracted
2 natural gas.

3 Q. What is the Company proposing as part of a pilot
4 program?

5 A. The Company is proposing to implement a three-year
6 pilot program designed to purchase CNG. The pilot
7 program will limit the incremental cost associated
8 with CNG premiums to \$175,000 per year. The Company
9 agrees to limit purchases to those certified and that
10 have obtained one of the following ratings:

11 1) MiQ; or

12 2) Oil and Gas Methane Partnership ("OGMP") 2.0.

13 The MiQ Standard was created to establish a practical
14 measure for assessing methane emissions management.

15 To carry out certification, upstream onshore and
16 offshore facilities must perform under three
17 criteria:

18 1) methane intensity below a certain threshold;

19 2) company practices that promote a culture of
20 emissions management; and

21 3) comprehensive monitoring technology deployment
22 to detect fugitive emissions.

23 MiQ has vowed to adapt the standard as technologies
24 evolve and companies grow and change.

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1 OGMP was created by the Climate and Clean Air
2 Coalition as a voluntary initiative to help companies
3 reduce methane emissions within oil and gas
4 operations. The most recent form of the
5 initiative, OGMP 2.0, includes five reporting levels,
6 with the highest level requiring that emissions
7 tracking and reports include site and source-level
8 measurements. Companies have three years to achieve
9 compliance for operated assets and five years for non-
10 operated assets.

11 Q. What will the \$175,000 of annual funding pay for?

12 A. The \$175,000 of annual funding will cover the premium
13 associated with procuring the certified natural gas.
14 The Company believes that this premium is
15 approximately \$0.03-\$0.07 per dekatherm.

16 Q. What locations would the Company procure CNG?

17 A. The Company would look to buy CNG into its existing
18 portfolio of assets at liquid trading points. The
19 Company would anticipate buying CNG at Texas Eastern's
20 M-2 Pool and/or Tennessee Gas Pipeline's Zone-4 200
21 leg pool near station 219.

22 Q. Would these purchases occur under the current Gas Cost
23 Management Plan?

DIRECT TESTIMONY OF MARC T. CUTHBERTSON
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1 A. Yes. The Company would incorporate these purchases
2 under its current Gas Cost Management Plan and would
3 seek least cost CNG supplies through a formal RFP
4 process. The Company will evaluate all CNG bid offers
5 based on the same criteria considered during
6 evaluation of traditional natural gas bid offers.
7 These criteria include supplier diversity, supplier
8 performance, price, receipt location. In addition to
9 the criteria considered for traditional natural gas
10 the Company will evaluate the specific third-party
11 certification associated with each bidder's CNG offer.
12 The Company would take delivery of firm supplies of
13 baseload CNG priced at an Inside FERC first of month
14 price based on the purchase point. The Company's
15 current plan allows for monthly baseload volumes at an
16 Inside FERC price, so the proposed CNG pilot's pricing
17 and baseload structure is compliant with the current
18 plan.

19 Q. What is the Company attempting to achieve with a CNG
20 Pilot Program?

21 A. The CNG Pilot Program will provide the Company with a
22 cost-effective opportunity to test CNG as a new
23 reliable, low cost and low carbon energy source for
24 its customers. In particular, the CNG Pilot Program

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1 allows the Company to gain market knowledge related to
2 the quantification and certification of methane
3 reductions associated with procuring CNG that has
4 lower methane intensity compared to national and
5 regional methane emission averages of conventional
6 natural gas. The Company is uniquely positioned to
7 procure natural gas from various sections of the
8 Northeast production basin and from various pipes,
9 which will allow the Company to thoroughly test the
10 value propositions of the pilot for its customers.

11

12 Q. Does this conclude your testimony?

13 A. Yes, it does at this time.

Verification

I, Marc T. Cuthbertson, Manager of the Gas Supply Administration Department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 2, Exhibit MTC-1, Exhibit MTC-2 Exhibit Nos. 4 (partial), 8 (partial), 9 and 32

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

Marc Cuthbertson

Marc T. Cuthbertson

This 31st day of January, 2024

TESTIMONY OF
MARC T. CUTHBERTSON
IN BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024-3045177

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
R-2024-3045177

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REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
R-2024-3045177

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

2 A. My name is Marc T. Cuthbertson, and my business address is 6363
3 Main Street, Williamsville, New York 14221.

4 **Q. Are you the same Marc T. Cuthberston that submitted Direct**
5 **Testimony in the instant docket?**

6 A. Yes. I submitted Distribution PGC Statement No. 2 along with Exhibit
7 MTC-1.

8 **Q. What is the subject of your rebuttal testimony?**

9 A. I am rebutting the direct testimony of Esysan A. Sakaya on behalf of
10 the Pennsylvania Public Utility Commission's ("Commission") Bureau
11 of Investigation and Enforcement ("I&E") regarding the Company's
12 proposed Certified Natural Gas ("CNG") Pilot Program ("CNG Pilot
13 Program"). I will also be rebutting the Direct Testimony of Mark D.
14 Ewen on behalf of the Pennsylvania Office of Small Business
15 Advocate ("OSBA") regarding the Company's CNG proposal.

16 **I. Rebuttal to Bureau of Investigation and Enforcement**

17 **Q. Do you agree with the findings and recommendations presented**
18 **in Mr. Sakaya's testimony related to the Company's CNG**
19 **proposal?**

20 A. No, I do not. I would like to address Mr. Sayaka's three concerns on
21 page 6 of his direct testimony.

22 **Q. First, Does the Company agree with Mr. Sakaya's comment on**

1 **page 6, “there are too many certification standards for this gas**
2 **product.”**

3 A. No. The Company is only pursuing certifications from two entities,
4 MiQ and OGMP 2.0. The MiQ Standard was created to establish a
5 practical measure for assessing methane emissions management.
6 To carry out certification, upstream onshore and offshore facilities
7 must perform under three criteria: 1) methane intensity below a
8 certain threshold; 2) company practices that promote a culture of
9 emissions management; and 3) comprehensive monitoring
10 technology deployment to detect fugitive emissions. Similarly,
11 OGMP was created by The Climate and Clean Air Coalition as a
12 voluntary initiative to help companies reduce methane emissions
13 within oil and gas operations. The most recent form of the initiative,
14 OGMP 2.0, includes five reporting levels, with the highest level
15 requiring that emissions tracking and reports include site and source-
16 level measurements. Companies have three years to achieve
17 compliance for operated assets and 5 years for non-operated assets.
18 MiQ provides specific criteria for methane intensity levels for each of
19 their certification levels¹. MiQ offers six reporting levels, ranging from
20 A to F. Grade A is the highest certification level given by MiQ for the
21 most stringent company practices, highest granularity of intensity

1 <https://miq.org/the-technical-standard/>

1 calculations, and most frequent monitoring deployment. OGMP 2.0
2 provides five reporting levels, ranging from one to five, with level five
3 being the highest standard for accuracy of emissions tracking and
4 reporting. MiQ and OGMP have a proven track record of working
5 with some of the largest natural gas producers in the country and
6 around the world to track and reduce emissions. MiQ and OMGP
7 2.0 are among the most well known and established certification
8 entities in the market. From a recent Platt's Gas Daily article, MiQ
9 now certifies 22 Bcf/d in the US, or around 20% of total natural gas
10 production. Many of the Company's suppliers are members of these
11 organizations including but not limited to: BP, Conoco, Coterra, EQT,
12 Equinor, Repsol, Chevron, and Shell².

13 **Q. What levels will the Company prioritize for the CNG Pilot**
14 **Program?**

15 A. The Company proposes prioritizing the following levels:

- 16 • MiQ Level A and Level B
- 17 • OGMP 2.0 Level 4 and Level 5

18 **Q. Please address Mr. Sakaya's second statement on page 6, "I do**
19 **not know the names of the potential independent third-party**
20 **certifiers and if there are any potential conflicts of interest."**

21 A. As stated previously, and more fully in my direct testimony

2 <https://ogmpartnership.com/our-member-companies/>

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 (Distribution St. No. 2, pp. 9-11), the Company is only pursuing
2 certifications from MiQ and or OGMP 2.0. The Company is not
3 affiliated with these entities and does not have any conflicts of
4 interest with these entities.

5 **Q. Do any of the Company's affiliates utilize the MiQ or OGMP 2.0**
6 **criteria? If so, does the Company plan to purchase CNG from**
7 **that affiliate(s)?**

8 A. Yes. Certain company affiliates have received certifications from
9 MiQ. The Company will not buy CNG from any of its affiliates.

10 **Q. Does the Company agree with the Mr. Sakaya's rationale for his**
11 **recommended denial of the proposed CNG Pilot Program?**

12 A. No.

13 **Q. Does the Company agree with Mr. Sakaya's concerns about**
14 **potential higher gas costs as a result of the purchase of CNG?**

15 A. No. The proposed CNG Pilot Program is consistent with how the
16 Company implements its obligation to pursue a least cost fuel
17 procurement strategy. The Company currently utilizes S&P Platts
18 Global ("Platts") Inside FERC monthly indices to purchase first of
19 month index priced gas as part of the current approved procurement
20 strategy. As a recent example, for the previous summer season from
21 April 1st, 2023 – October 31st, 2023, the Company purchased 16%
22 of its total portfolio utilizing published Platts Inside FERC Monthly
23 Price indices. Consistent with that approach, the Company plans to

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 utilize published Platts Inside FERC Monthly indices for the CNG
2 Pilot Program to ensure fair market-based transparent pricing of the
3 underlying CNG commodity cost.

4 **Q. Does the Company pay incremental fees for any of its**
5 **transactions for traditional natural gas supplies?**

6 A. Yes. Under its least cost purchasing strategy, the Company
7 purchases gas with different terms and delivery options. For
8 example, the Company incurs demand fees for winter take or release
9 transactions, demand charges for winter peaking supplies, and
10 additional incremental charges for fixed price transactions. For the
11 winter of 2023-2024, the Company entered into take or release
12 contracts with suppliers with demand charges ranging from \$0.01 to
13 \$0.08. These demand charges are paid to suppliers to provide the
14 Company with delivery flexibility of firm supplies during varying
15 temperature conditions during the winter delivery period. The
16 Company also incurs demand charges for peaking service, where
17 the Company does not hold firm upstream capacity and relies on
18 third parties to make deliveries directly to the Company's
19 interconnects on National Fuel Gas Supply Corporation. During the
20 winter of 2023-2024, the demand charges for this service ranged
21 from \$0.06 - \$0.10 per dekatherm ("Dth").

22 **Q. Does the Company believe that the projected cost of the**
23 **certification is in line with other charges incurred with buying**

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 **traditional gas?**

2 A. The Company believes that the CNG premium of approximately
3 \$0.03 to \$0.07 per Dth is consistent with incremental costs that are
4 typically paid for contracting for term gas. The Company has spoken
5 to numerous suppliers that sell CNG and has confirmed that the
6 quoted premiums are reflective of the current market. Platt's S&P
7 Global Commodity Insights Gas Daily article from March 20, 2024
8 has published Methane Intensity Premiums and for Appalachian-
9 Pennsylvania and Appalachian-Ohio the premiums were listed at
10 \$0.055 and \$0.056. The Company would expect to purchase CNG
11 from these basin locations.

12 **Q. Please respond to Mr. Sakaya's statement, "NFG cannot reliably**
13 **estimate the premium difference in procuring CNG versus**
14 **conventional natural gas. In short, NFG provided no forecast of**
15 **CNG prices which makes it impossible to determine whether the**
16 **proposed pilot will satisfy the least cost procurement**
17 **requirement."**

18 A. In addition to the previously described measures to ensure fair
19 market-based pricing, the Company proposes an additional measure
20 to provide CNG cost certainty. The Company is proposing that any
21 incremental fee associated with the certification not exceed \$0.07 on
22 a per unit basis. This would be consistent with incremental fees that
23 the Company has historically paid for term gas supplies. The

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 Company would limit the annual cost of these potential incremental
2 fees to \$175,000/year. Therefore, Distribution's proposal addresses
3 Mr. Sakaya's concern on this point.

4 **Q. How does the Company propose to quantify and track any CNG**
5 **premium throughout the Request for Proposal ("RFP")**
6 **process?**

7 A. The Company proposes to issue an RFP for seasonal baseload
8 purchases. The Company would solicit bids from suppliers specifying
9 Platts Inside FERC monthly index pricing with an index adjustment
10 for the first of month price and a separate line item for the fee
11 associated for the CNG certification. This RFP structure will allow the
12 Company to identify the associated incremental CNG fees.

13 **Q. Does the Company agree with Mr. Sayaka's recommendation**
14 **that the CNG Pilot Program be denied?**

15 A. No. The Company believes that the proposed CNG Pilot Program as
16 outlined in my direct testimony and further clarified here is consistent
17 with non-certified natural gas transactions that the Company enters
18 into in order to fulfill its PGC supply needs.

19 **Q. Please address Mr. Sakaya's third concern on page 6 that**
20 **"Company testimony did not detail how the program would be**
21 **subject to reporting requirements during the pilot run to gauge**
22 **progress."**

23 A. The Company agrees to the reporting requirements suggested by

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 I&E should the CNG Pilot Program be approved as part of this
2 proceeding. More specifically, the Company agrees that the CNG
3 purchase price should be comparable to the cost of traditional gas
4 purchases. The Company also agrees to provide a report in future
5 1307(f) filings describing the details of the CNG Pilot Program for the
6 duration of the pilot. The annual report will describe the progress of
7 the CNG Pilot Program and will include purchase reporting on the
8 following items:

- 9 • The total volume of CNG purchased;
- 10 • Annual CNG premiums spent by the year;
- 11 • Number of suppliers;
- 12 • Names of all associated certifications; and
- 13 • Methane emissions intensity of the CNG purchased.

14 **Q. Does this conclude your rebuttal testimony of Mr. Sakaya?**

15 **A.** Yes, at this time.

16 **II. Rebuttal to Pennsylvania Office of Small Business Advocate**

17 **(“OSBA”)**

18 **Q. Do you agree with the findings and recommendations presented**
19 **in Mr. Ewen’s testimony related to the Company’s CNG**
20 **proposal?**

21 **A.** No, I do not.

22 **Q. Please address the concerns expressed by Mr. Ewen regarding**

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 **the CNG Pilot Program.**

2 A. The Company believes that the CNG Pilot Program is consistent with
3 the least cost procurement mandate. Many of the issues raised by
4 Mr. Ewen were also raised by Mr. Sayaka and were addressed
5 previously in my rebuttal testimony.

6 **Q. Please address Mr. Ewen’s statement, “it appears that this**
7 **proposal to purchase higher cost gas may run afoul of least**
8 **cost gas procurement requirements.”**

9 A. I disagree with Mr. Ewen’s concerns. The Company believes that the
10 CNG premium of approximately \$0.03 to \$0.07 is in line with
11 incremental costs that the Company typically pays for contracting
12 winter term gas supplies. The Company incurs demand charges for
13 winter take or release transactions, demand charges for winter
14 peaking supplies, and additional incremental charges for fixed price
15 transactions. I address this in further detail above.

16 **Q. Please address Mr. Ewen’s statement that “[t]he Company**
17 **should complete...specific plan for offering this supply option**
18 **to customers.”**

19 A. The Company has provided a detailed description of how the CNG
20 Pilot Program will be incorporated into its current gas supply portfolio
21 for customers, in compliance with the least cost procurement
22 mandate. Following its standard procurement procedures for
23 ensuring a competitive bid process, the Company will issue a written

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 RFP to solicit bids from its approved suppliers.

2 **Q. Please describe the counterparties from which the Company**
3 **will solicit responses for CNG supplies.**

4 A. The Company will send the formal RFP to natural gas marketers and
5 natural gas producers with which the Company has existing NAESB
6 or Master Gas Purchase contracts. The Company has existing
7 purchase contracts with numerous natural gas producers that have
8 achieved MiQ or OGMP CNG certification for their production
9 volumes. Also, third party natural gas marketing companies with
10 which the Company has existing contracts manage the CNG
11 supplies of producers with which the Company may not have an
12 existing NAESB agreement. Given the breadth of the Company's
13 producers and marketers, the Company is confident that it will
14 receive numerous bids with sufficient volumes and competitive price
15 offers to satisfy the requirements of the proposed CNG Pilot
16 Program.

17 **Q. Where does the Company propose taking receipt of CNG**
18 **Supplies?**

19 A. The Company will solicit CNG bids for delivery of supplies at many of
20 the receipt points at which the Company currently purchases gas for
21 its customers. These are existing receipt points that flow into the
22 Company's firm upstream transportation contracts. The following
23 interconnections will be included on the CNG RFP:

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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- 1 1. Texas Eastern M2 Pooling Point (Meter 79508)
- 2 2. Tennessee Gas Pipeline Zone-4 219 Pool (Meter 420867)
- 3 3. Tennessee Gas Pipeline Zone-4 313 Pool (Meter 420891)
- 4 4. Columbia Gas Pipeline TCO Pool (Meter TCO Pool)

5 **Q. Please describe the natural gas indices that the Company will**
6 **consider under the CNG Pilot Program.**

7 A. As described earlier, the Company will utilize Platts Inside FERC
8 monthly indices for the corresponding purchase points listed above.
9 Those indices include:

- 10 1. Inside FERC Texas Eastern, M-2 receipts
- 11 2. Inside FERC Tennessee, zone 4-200 leg
- 12 3. Inside FERC Tennessee, zone 4-313 Pool
- 13 4. Inside FERC Columbia Gas, App

14 **Q. Does the Company utilize these monthly price indices for**
15 **purchasing its traditional natural gas supplies?**

16 A. Yes, the Company currently relies on these liquid price indices for
17 procurement of its current supplies.

18 **Q. Please describe the certification levels and certifiers the**
19 **Company would include on the RFP.**

20 A. The Company proposes prioritizing the following levels:

- 21 • MiQ Level A and Level B
- 22 • OGMP 2.0 Level 4 and Level 5

23 **Q. Please describe the duration of the deals for the RFP.**

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 A. The Company will issue an RFP for supplies that will not exceed one
2 year. The Company will likely enter into seasonal transactions to
3 maintain operational flexibility. Seasonal transactions are defined as
4 November 1st to March 31st (winter) and April 1st – October 31st
5 (summer).

6 **Q. Please describe the maximum daily quantity of CNG and the**
7 **associated premiums for which the Company will be**
8 **contracting after the completion of the formal RFP process.**

9 A. The daily quantity of CNG and the associated premium is dependent
10 on the proposed cost cap. The Company has proposed an annual
11 cap of \$175,000 of funding for the CNG Pilot Program to cover the
12 certification cost premium. The Company will also cap the CNG unit
13 cost premium to \$0.07 per Dth for the certification. The Company will
14 limit the daily quantity of CNG to 7,500 Dth/day. The proposed CNG
15 Pilot Program will have an upper limit on both the daily quantity of
16 CNG, the incremental fee per Dth of the certification, and the annual
17 CNG premium spent.

18 **Q. Please describe the remaining factors that are unknown at this**
19 **time.**

20 A. The unknown information at this time are which counterparties will
21 submit bids and with whom the Company will subsequently enter into
22 a transaction. The Company will evaluate all bid responses by
23 applying the CNG Pilot Program parameters, in addition to its current

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 procurement evaluation practices, to execute a term contract CNG
2 supplies. Under the Company's current procurement evaluation
3 practices, the Company strives to enter into transactions with
4 suppliers to ensure least cost and reliable supplies. Other factors
5 that remain unknown until bid offers are received from suppliers are
6 the exact index premiums and certification premiums. This is
7 consistent with all of the Company's RFPs.

8 **Q. Does the Company believe it has provided enough details**
9 **regarding the CNG Pilot Program to address Mr. Ewen's**
10 **concerns that the Company did not provide a "specific plan for**
11 **offering this supply option to customers."**

12 A. Yes. The Company has clearly defined the RFP process and has
13 shown that it is consistent with the current RFP structure that the
14 Company employs for term gas supplies.

15 **Q. Is the Company willing to provide a draft RFP that would be**
16 **utilized to procure supplies as part of the CNG Pilot Program?**

17 A. Yes, a sample draft RFP is provided as GSA Exhibit-MTC-1-R.

18 **Q. Please address Mr. Ewen's statement, "It is not clear how NFG**
19 **intends to offer this supply option to customers, including**
20 **whether it contemplates voluntary participation or general cost**
21 **recovery across all customers."**

22 A. The Company is proposing to purchase CNG supplies for all its sales
23 customers and recover those costs from all sales customers. The

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
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1 Company is not proposing to offer CNG as a distinct voluntary tariff
2 sales service at this time. The \$175,000 yearly premium cap should
3 result in minimal impacts to customers' bills.

4 **Q. Please address Mr. Ewen's third concern that "natural gas**
5 **customers can shop for gas suppliers in Pennsylvania. The**
6 **Company has made no representations as to whether CNG is**
7 **already an option for its customers."**

8 A. The Company is unaware of the exact products that third party
9 marketers are currently offering to potential customers.

10 **Q. Would you like to address Mr. Ewen's statement, "A quick**
11 **internet search indicates that there is publicly available**
12 **information concerning the structure, viability, and integrity of**
13 **the certifying organizations, along with information concerning**
14 **the efficacy and stringency of the audit and certification**
15 **process."**

16 A. Yes. The Company is unaware of the internet searches that Mr.
17 Ewen performed that questioned the viability and integrity of the
18 certifying organizations. Mr. Ewen's testimony did not provide any
19 specific references to the companies from which the Company would
20 seek certifications under the CNG Pilot Program.

21 **Q. Does the Company agree with Mr. Ewen's recommended denial**
22 **of the proposed CNG Pilot Program?**

23 A. No. The Company has agreed to provide an annual report on the

REBUTTAL TESTIMONY OF MARC T CUTHBERTSON
R-2024-3045177

1 CNG Pilot Program, if approved, as part of its annual 1307(f) filing.
2 Further, as detailed above, the Company is proposing to limit the
3 purchases of CNG supply within specific price triggers and with an
4 overall program cost ceiling, reflective of the incremental costs the
5 Company experiences when purchasing winter term gas supplies.
6 Lastly, and importantly, the Company believes that the CNG Pilot
7 Program is consistent with the least cost procurement mandate.

8 **Q. Does this conclude the rebuttal testimony of Mr. Ewen?**

9 **A.** Yes, at this time.

National Fuel Distribution DRAFT CNG RFP

Counterparty	Term	Daily Quantity	Receipt Location ⁽¹⁾	Pricing Index (Inside FERC)	Inside FERC Natural Gas Index Adjustment	Certification Company ⁽²⁾	Certification Level	Premium for Certification (\$/Dth)
	4/1/2024 - 10/31/2024							

Footnotes:	
(1)	Receipt Locations Limited to the following: Texas Eastern M2 TGP 219 Pool TGP 313 Pool Columbia TCO Pool
(2)	Approved Certification Companies include: MiQ OGMP 2.0

Verification

I, Marc Cuthbertson, Manager, of the Gas Supply Administration Department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 2R Rebuttal Testimony of Marc T Cuthbertson, Exhibit MTC-1-R

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

Marc Cuthbertson

Marc T. Cuthbertson

This 22nd day of March, 2024

TESTIMONY OF
CAITLIN DIGIORE
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024- 3045177

DIRECT TESTIMONY OF CAITLIN DIGIORE
DOCKET NUMBER R-2024-3045177

- 1 Q. State your name and business address.
- 2 A. My name is Caitlin DiGiore and my business address is 6363 Main
3 Street, Williamsville, New York, 14221.
- 4 Q. By whom are you employed and in what capacity?
- 5 A. I am employed by National Fuel Gas Distribution Corporation
6 ("Distribution") as a Regulatory Analyst II.
- 7 Q. Can you please describe your responsibilities as Regulatory Analyst II
8 for Distribution?
- 9 A. I work under the direct supervision of the Deputy General Counsel
10 and Chief Regulatory Counsel of the Legal Department. I prepare
11 analyses used to develop Company positions regarding federal
12 regulatory matters (e.g. pipeline filings and generic Federal Energy
13 Regulatory Commission ("FERC") initiatives), identifying potential cost
14 impacts to customers in Distribution's Pennsylvania and New York
15 jurisdictions.
- 16 Q. Summarize your education and prior work experience.
- 17 A. I graduated from the University at Buffalo in May 2013, with a
18 Bachelor of Science degree in Business Administration, with a
19 Finance concentration. In May 2014, I began my employment at a
20 financial services institution as a Margin Analyst. In April 2016, I
21 joined Distribution as a Rate Analyst I. In October 2021, I transferred
22 to the Legal Department as Regulatory Analyst II, my current position.
- 23 Q. What is the subject of your testimony?
- 24 A. I am testifying to PGC Exhibit Nos. 6 and 6-A.

DIRECT TESTIMONY OF CAITLIN DIGIORE
DOCKET NUMBER R-2024-3045177

1 Q. Were all sections of PGC Exhibit Nos. 6 and 6-A prepared under
2 your supervision and direction?

3 A. Yes, they were.

4 Q. Are there any corrections to PGC Exhibit No. 6?

5 A. No, there are no corrections to PGC Exhibit No. 6.

6 Q. Please explain PGC Exhibit Nos. 6 and 6-A.

7 A. Exhibits 6 and 6-A respond to the Commission's filing requirement at
8 52 Pa. Code § 53.64(c)(4) and describe Distribution's involvement in
9 proceedings before FERC and other appropriate regulatory and
10 judicial bodies. These proceedings encompass FERC rulemakings
11 and other generic industry-wide issues, as well as proceedings
12 involving the individual pipelines on which Distribution transports
13 and/or stores gas. Distribution participates in FERC proceedings,
14 both independently and as a member of the American Gas
15 Association ("AGA").

16 Q. In what types of FERC proceedings does Distribution intervene?

17 A. Distribution intervenes in major rate filings, periodic adjustments to
18 trackers/surcharge mechanisms that impact rates paid by
19 Distribution, various refunds/credits, modifications to pipeline tariff
20 provisions impacting service to Distribution, and construction
21 project/abandonment filings for facilities that potentially impact
22 service to Distribution and other matters that may have a generic
23 policy impact beyond the scope of the pipeline's filing.

DIRECT TESTIMONY OF CAITLIN DIGIORE
DOCKET NUMBER R-2024-3045177

1 Q. In which filings did Distribution intervene during the historical
2 period?

3 A. Exhibit 6-A lists the dockets in which Distribution intervened,
4 organized by pipeline. The date and type of intervention, along with
5 a description of the docket, is provided in the exhibit.

6 Q. Were there any major rate proceedings during the historic period?

7 A. Yes, on July 31, 2023, National Fuel Gas Supply Corporation filed
8 a Section 4 Rate Case in Docket No. RP23-929 proposing an
9 approximately 68% increase to rates. On August 31, 2023, the FERC
10 accepted and suspended the tariff records to be effective February 1,
11 2024, subject to refund and the outcome of a hearing. Distribution
12 filed a protest and intervention, and it is participating in the proceeding
13 as part of a customer group. The matter is currently ongoing.
14 Texas Eastern Transmission, LP ("Texas Eastern") filed a major
15 Section 4 rate case in Docket No. RP21-1001 on July 30, 2021.
16 The FERC rejected this filing and on September 30, 2021,
17 Texas Eastern re- filed a Section 4 rate case in Docket No.
18 RP21-1188. Distribution joined a customer group with similarly
19 situated local distribution companies. As part of the customer group,
20 Distribution engaged in a series of settlement negotiations that
21 resulted in a Stipulation & Agreement filed on September 8,
22 2022. The FERC issued a Letter Order approving the Stipulation
23 Agreement on November 30, 2022. The FERC issued an Order on

DIRECT TESTIMONY OF CAITLIN DIGIORE
DOCKET NUMBER R-2024-3045177

1 April 3, 2023 accepting Texas Eastern's compliance filing

2 tariff records. On May 12, 2023, Texas Eastern issued a Base

3 Rate Refund Report, which the FERC approved on June 9, 2023.

4 Q. Were there any other pipeline filings impacting the rates paid by
5 Distribution?

6 A. Yes. Distribution intervened in several dockets on Columbia Gas
7 Transmission, Supply, Tennessee Gas Pipeline and Texas Eastern
8 updating other existing tracker mechanisms.

9 Q. How does Distribution approach generic issues at FERC?

10 A. Distribution participates through AGA, working with other gas
11 utilities with similar interests. As an industry association, AGA's
12 filings generally have more impact at FERC than the impact of
13 individual utility filings.

14 Q. What types of FERC issues did Distribution address through its
15 participation in AGA during the historic period?

16 A. AGA conducts outreach to FERC Staff, as necessary, to obtain a
17 better understanding of the issues under consideration. During the
18 historic period, significant topics included filing and reporting
19 requirements, renewable natural gas, price indices, certification of
20 facilities, energy derivative matters and pipeline safety.
21 AGA also provides support to gas utilities involved with the
22 deliberations at the North American Energy Standards Board
23 (often in response to FERC actions) to ensure meaningful
24 standards development as well as to protect against standards

DIRECT TESTIMONY OF CAITLIN DIGIORE
DOCKET NUMBER R-2024-3045177

1 that would shift costs to gas utilities and/or degrade the
2 reliability of firm transportation services delivered to the city gate.

3 Q. Does this conclude your testimony?

4 A. Yes, at this time.

Verification

I, *Caitlin DiGiore, Regulatory Analyst II*, of the *Legal Department* of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 3
Exhibit Nos. 6

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

~~/s/ Caitlin DiGiore~~ _____
Caitlin DiGiore

This 31st day of January, 2024

TESTIMONY OF
GREGORY D. HARTS
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024- 3045177

DIRECT TESTIMONY OF Gregory D. Harts
PGC R-2024-3045177

1 Q. Please state your name and business address.

2 A. My name is Gregory Harts. My business address is
3 6363 Main Street, Williamsville, NY 14421.

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

5 A. I am employed as an Assistant Manager, by National
6 Fuel Gas Distribution Corporation ("Distribution" or
7 the "Company"). Distribution is a regulated gas
8 distribution company operating in western
9 Pennsylvania.

10 Q. Please provide your educational background.

11 A. I graduated from Syracuse University, in 2013, with
12 a Bachelor of Science degree in Mechanical
13 Engineering. Additionally, I obtained a Master of
14 Science degree in Business Administration from The
15 State University of New York at Buffalo in 2020.

16 Q. Please provide your professional experience.

17 A. I worked for National Fuel Gas Supply Corporation
18 within the Engineering Services department as an
19 Associate Engineer, Engineer I, and Engineer II from
20 2014 to 2021, and I have worked for Distribution as
21 a Rate Analyst III and Assistant Manager from 2021
22 to date.

DIRECT TESTIMONY OF Gregory D. Harts
PGC R-2024-3045177

1 Q. Have you previously testified before the
2 Pennsylvania Public Utility Commission
3 ("Commission")?

4 A. Yes, I have submitted testimony before the
5 Commission as part of the Company's recent rate case
6 filing at Docket No. R-2022-3035730 and the
7 Company's 2023 1307(f) filing, PGC R-2023-3037428.

8 Q. Have you previously testified before any other
9 regulatory commissions?

10 A. Yes, I have presented testimony before the New York
11 State Public Service Commission in Docket No. 23-G-
12 0627.

13 Q. What is the subject of your direct testimony?

14 A. I am testifying with regard to PGC Exhibit Nos. 7-A,
15 15, and 26-A.

16 Q. Were these exhibits prepared by you or prepared
17 under your supervision and direction?

18 A. Yes, they were.

19 Q. Is the content of these exhibits true and correct to
20 the best of your knowledge, information, and belief?

21 A. Yes, it is.

22 Q. Please explain PGC Exhibit No. 7-A.

DIRECT TESTIMONY OF Gregory D. Harts
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1 A. PGC Exhibit No. 7-A is Distribution's work product
2 for the filing requirement at 52 Pa. Code §53.64
3 (c)(5), which requires that a list and update of any
4 gas supply and demand projections be provided to the
5 Commission for any purpose. Page 2 of PGC Exhibit
6 No. 7-A provides a copy of Distribution's Form-IRP-
7 GAS-1A: Annual Gas Demand Requirements, which has
8 been filed pursuant to 52 Pa. Code §59.81-84.

9 Q. Please explain PGC Exhibit No. 15.

10 A. PGC Exhibit No. 15 identifies and supports
11 Distribution's projected design peak day
12 requirements for the twelve months ending September
13 30, 2025. Page 3 shows the projected peak day
14 requirement. Data based on 74 heating degree days is
15 provided because this level of degree days was used
16 for peak day planning purposes, as further described
17 in PGC Exhibit No. 24. Pages 4 through 12 establish
18 the base case design peak day. For the heat sensitive
19 classes (both retail sales and transportation
20 service) such as residential, commercial, and public
21 authority, Distribution utilizes a method of
22 extracting a base load volume and computing a daily

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1 heating volume for 74 heating degree days. The daily
2 base load volume is added to the daily heating volume
3 to determine the base case peak day sales. Gas usage
4 of customers in the industrial classes, Small Volume
5 Industrial Service ("SVIS"), Intermediate Volume
6 Industrial Service ("IVIS"), Large Volume Industrial
7 Service ("LVIS"), Large Industrial Service ("LIS"),
8 and Daily Metered Large Manufacturing Transportation
9 Service ("DMLMTS"), is computed based on an operating
10 schedule. For the SVIS and IVIS classes, Distribution
11 utilizes an operating schedule of 21 working days in
12 a month to calculate peak day sales. For the LVIS,
13 LIS and DMLMTS classes, Distribution utilizes
14 customer operating schedules, as shown on Pages 11
15 and 12, to calculate peak day sales. Pages 13 and 16
16 show the residential model variables, pages 13, 14,
17 16, and 17 show the commercial model variables, pages
18 14, and 17 show the industrial model variables, and
19 pages 15 and 18 show the public authority model
20 variables used in the econometric models for each of
21 the respective revenue classes. Page 19 provides the
22 number of extreme degree days based on a National

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1 Oceanic and Atmospheric Administration ("NOAA")
2 calendar day (12am - 12am), including the mean
3 temperature, for the most recent heating seasons over
4 the previous 30 years.

5 Q. Please explain PGC Exhibit No. 26-A.

6 A. PGC Exhibit No. 26-A, page 2, provides
7 Distribution's estimate of the 2025 design peak day
8 requirements based on 74 heating degree days. The
9 term "design peak day" refers to the practice that
10 is standard in the natural gas industry under which
11 pipeline capacity planning, storage capacity
12 planning, and natural gas supply planning are based
13 on customers' requirements on the coldest winter day
14 reasonably expected to be experienced. An
15 explanation of Distribution's design peak day
16 requirements, including the requirements of
17 transportation service customers, is provided in PGC
18 Exhibit No. 15.

19 Q. Why was 74 heating degree days used in the
20 calculation of design peak day requirements?

21 A. After a review of the coldest days experienced
22 during several winter heating seasons, as well as a

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1 review of what design peak days other local
2 distribution companies ("LDCs") prepare for,
3 Distribution determined that the most appropriate
4 level of degree days for peak day planning in its
5 service territory was 74 heating degree days.
6 Distribution has had two days in the past 30 years
7 where there has been at least 74 heating degree
8 days, based on a typical gas day (10am - 10am). In
9 Distribution's 2000 1307(f) proceeding, the
10 Commission concluded that this was a reasonable
11 level of heating degree days to use for system
12 planning purposes.

13 "Upon our careful review of the recommendation of
14 the ALJ and the position of the Parties, we find
15 that the ALJ's recommendation of approval of
16 NFGD's proposal to use 74 heating degree days for
17 purposes of both planning the necessary levels of
18 pipeline and storage capacity on interstate
19 pipeline companies and for allocating costs of
20 capacity among classes of customers is
21 reasonable." (Opinion and Order, R-994898,
22 Adopted: August 17, 2000, pg. 17.)
23

24 Q. Does this conclude your direct testimony?

25 A. Yes, it does at this time.

Verification

I, *Gregory D. Harts*, Assistant Manager, of the Rates & Regulatory Affairs Department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 4, Direct Testimony of Gregory D. Harts
Exhibit Nos. 7-A, 15, and 26-A

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

Gregory D. Harts

Gregory D. Harts

This 31st day of January, 2024

TESTIMONY OF
GREGORY D. HARTS
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024- 3045177

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Gregory D. Harts

1 Q. Please state your name and business address.

2 A. My name is Gregory D. Harts. My business address is

3 6363 Main Street, Williamsville, New York 14221.

4

5 Q. Did you previously submit direct testimony in this

6 proceeding?

7 A. Yes, I submitted PGC Statement No. 4.

8

9 Q. What will you be addressing in your Rebuttal Testimony?

10 A. I will be addressing comments made by Jerome D. Mierzwa

11 on behalf of the Office of Consumer Advocate ("OCA").

12

13 Q. What are your observations concerning the testimony of

14 the OCA?

15 A. Mr. Mierzwa is recommending that National Fuel Gas

16 Distribution Corporation ("Distribution" or the

17 "Company"), further analyze its design day forecasting

18 model and address Mr. Mierzwa's concern that the

19 Company appears to be overestimating its design day

20 requirements. Additionally, Mr. Mierzwa is recommending

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Gregory D. Harts

1 that, until further analysis is completed, the Company
2 not increase its interstate pipeline capacity
3 entitlements. This issue is addressed in the rebuttal
4 testimony of Ms. Petko, Distribution St. No. 7R.

5

6 Q. Do you agree that the design day forecasting model
7 overestimates the Company's design day requirements?

8 A. No, I do not. Mr. Mierzwa is basing his conclusion on a
9 linear extrapolation of the peak day usage from three
10 prior winter seasons 2021-2022, 2022-2023, and 2023-
11 2024 (a winter season being November through March)
12 which, overall, were 5.0%, 7.6%, 13.1% (through
13 February 2024) warmer than normal, respectively. The
14 Company's service territory experienced an average of
15 48 heating degree days ("HDD") over the 3-day peak
16 period in January 2022, 53 HDD in December of 2022, and
17 51 HDD in January of 2024. Historically, winter periods
18 have averaged between 40 - 67 HDDs. This can be seen in
19 Exhibits LAP-2 and PGC Exhibit 14.

20 In addition, the Company's service territory

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Gregory D. Harts

1 continues to experience volatility in temperature and
2 weather. Therefore, the Company needs to be prepared to
3 provide safe and reliable service during short and
4 extreme weather events throughout multiple parts of the
5 service territory.

6 A linear extrapolation of actual usage on a
7 seasonably warm peak day of 48, 53, and 51 HDDs to a
8 design day of 74 HDDs cannot be exclusively relied
9 upon because it can significantly underestimate design
10 day usage. Mr. Mierzwa acknowledges this dynamic in
11 his testimony on page 10, where he states:

12 "NFGD's design day forecasting model utilizes
13 monthly usage to project the demands of weather-
14 sensitive customers. This tends to underestimate
15 actual demands under colder temperatures because the
16 usage per HDD of weather-sensitive customers tends to
17 increase as HDDs increase."

18 As this statement notes, the relationship
19 between usage and HDD is not linear, thus estimating

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Gregory D. Harts

1 actual design day usage from a seasonably warm peak
2 day from a single winter significantly understates
3 the forecast design day.

4 A review of actual design day estimates from the
5 prior ten winters demonstrates that the Company's
6 design day forecast is reasonably in-line with
7 historical actuals. In fact, the design day estimate
8 from the winter of 2013-2014, which experienced peak
9 day usage at 68 HDDs on January 7, 2014, resulted in
10 a peak day requirement that exceeded the Company's
11 forecast and contracted pipeline capacity at the
12 time, as noted in Exhibit LAP-2.

13 This demonstrates the reasonableness of the
14 Company's model. The model is not intended to
15 forecast usage for days that are significantly lower
16 than 74 HDD. It is intended to forecast usage when
17 temperatures are extremely cold, so that the Company
18 can ensure that it has sufficient supply to provide
19 reliable service to customers. Based upon the 2014
20 winter, the Company's model is not overstating

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Gregory D. Harts

1 capacity when the HDD are close to 74.

2 Lastly, it should be noted that the forecasting
3 model that the Company uses to estimate design day has
4 not changed over the reported historical period.

5

6 Q. Do you have other observations concerning the
7 testimony of the OCA?

8 A. Yes. Usage on a peak day could also be impacted by
9 several other factors that can be unique to that day
10 or winter season, which is why relying on a single
11 winter's estimate can be problematic. For example, a
12 peak day may fall on a weekend or weekday. During the
13 winter season of 2022-2023, the peak day of December
14 24, 2022, fell on a Saturday.

15

16 Q. Should the Company evaluate whether daily rather than
17 monthly usage should be used to forecast design day
18 demands?

National Fuel Gas Distribution Corporation
Rebuttal Testimony of Gregory D. Harts

1 A. No. The Company does not obtain daily meter read data
2 for the vast majority of its customers. For most
3 customers, consumption volumes are obtained and
4 billed on a monthly basis. As a result, historical
5 daily consumption data is not available to be
6 utilized for forecasting purposes.

7

8 Q. Does this conclude your testimony?

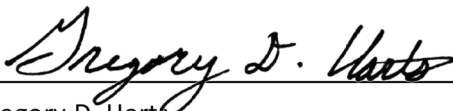
9 A. Yes, at this time.

Verification

I, Gregory D. Harts, Assistant Manager, of the Rates and Regulatory Affairs department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 4R Rebuttal Testimony of Gregory D. Harts

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.



Gregory D. Harts

This 22nd day of March, 2024

TESTIMONY OF
NICHOLAS J. HEWA
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024-3045177

DIRECT TESTIMONY OF NICHOLAS J. HEWA
R-2024-3045177

1 Q. Please state your name and business address.

2 A. My name is Nicholas Joseph Hewa and my business address is 6363 Main Street, Williamsville, New
3 York 14221.

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

5 A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or the
6 "Company") as a Rate Analyst II in the Rates and Regulatory Affairs Department.

7 Q. Will you state briefly your educational background and experience?

8 A. I received a Bachelor's of Business Administration with a concentration in Finance from the
9 University at Buffalo in May 2018. I went on to receive a Master's of Business
10 Administration with a specialization in Finance from Canisius College in August 2019. Prior
11 to joining Distribution, I interned at Integer Holdings Corporation, a medical device outsource
12 manufacturer, within the financial planning and analysis department for about 6 months,
13 leaving in August 2019. After my internship, I worked at Ingram Micro, an information
14 technology product and service distributor, for about 6 months, specializing in data analysis,
15 leaving in early March 2020. Later in March 2020, I was hired by Distribution as a Rate
16 Analyst I in the Rates and Regulatory Affairs Department. In February 2022, I was promoted
17 to my current position of Rate Analyst II.

18 Q. Please summarize your responsibilities in this position relative to this proceeding.

19 A. My responsibilities include preparation of filings relating to recovery of gas costs. Therefore, I am
20 familiar with the Pennsylvania Public Utility Commission's ("Commission") procedures for gas cost
21 recovery.

22 Q. What is the purpose of your testimony?

23 A. I am testifying in support of PGC Exhibit Nos. 1, 2, 3, 21, 21-A, 21-B and 21-C.

24 Q. Please describe PGC Exhibit 1.

25 A. PGC Exhibit 1 details, by month, for the twelve months ended November 30, 2023, volumes
26 and costs of gas purchased from upstream suppliers, local production, and Peoples TWP LLC.
27 The data shown in PGC Exhibit No. 1 represents historical information from Distribution's
28 books and records.

DIRECT TESTIMONY OF NICHOLAS J. HEWA
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1 The category entitled "Upstream Purchases" on PGC Exhibit No. 1, Schedule 1,
2 Sheet 1 reflects Distribution's cost of purchasing gas from various upstream producers, whose
3 gas is transported by long-line interstate pipeline companies to National Fuel Gas Supply
4 Corporation ("Supply"), which in turn delivers the gas supplies to Distribution. A monthly
5 breakdown of Distribution's commodity and demand costs from upstream suppliers is
6 provided in PGC Exhibit No. 1, Schedule 1, Sheet 2. Further detail of Distribution's costs
7 from upstream suppliers is provided in PGC Exhibit No. 1, Schedule 2, Sheet 1.

8 The category entitled "Storage" on PGC Exhibit No. 1, Schedule 1, Sheet 1 reflects
9 Distribution's charges from storage providers for space required within their facilities and the
10 cost of gas purchased for storage. A monthly breakdown of Distribution's rental and storage
11 gas cost is provided in PGC Exhibit No. 1, Schedule 2, Sheet 2.

12 The category entitled "Transportation" on PGC Exhibit No. 1, Schedule 1, Sheet 1
13 reflects charges for transportation of gas purchased from suppliers. A monthly breakdown of
14 Distribution's costs for transportation of upstream gas is provided in PGC Exhibit No. 1,
15 Schedule 4.

16 The Demand cost of gas is split between Demand-Natural Gas Supply ("Demand-
17 NGS") and Demand-Distribution Charge ("Demand-DC"). Demand-DC includes the cost of
18 pipeline capacity and storage needed to provide peak delivery/temperature swing
19 requirements for Distribution's sales and SATC customers. These are costs that Distribution
20 would incur even if all customers converted to transportation service. A certain amount of
21 capacity would have to be maintained to serve these peaking requirements. PGC Exhibit No.
22 1, Schedule 5 provides a detailed calculation of the Demand-DC costs. Demand-NGS
23 includes the remaining demand costs incurred to provide sales service. The Demand-NGS
24 costs represent total demand costs less Demand-DC costs.

25 Distribution shares Capacity Release Revenues on a 75%/25% basis. The
26 transportation amount includes the adjustment necessary to flow through 75% of these
27 revenues to ratepayers.

DIRECT TESTIMONY OF NICHOLAS J. HEWA
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1 The category entitled "Transportation Credit" on PGC Exhibit No. 1, Schedule 1,
2 Sheet 1 reflects the costs recovered from transportation customers. A monthly breakdown of
3 Distribution's transportation credits is provided in PGC Exhibit No. 1, Schedule 1, Sheet 4.

4 The category entitled "Local Production" on PGC Exhibit No. 1, Schedule 1, Sheet 1
5 reflects Distribution's cost of gas purchased from local producers. A monthly breakdown of
6 Distribution's cost of gas purchased from local producers is provided in PGC Exhibit No. 1,
7 Schedule 1, Sheet 3.

8 The category entitled "Peoples Gas Company" on PGC Exhibit No. 1, Schedule 1,
9 Sheet 1 reflects Distribution's cost of purchasing a small volume of gas from Peoples TWP
10 LLC, under its Rate Schedule SWS - Small Wholesale Service. A monthly breakdown of
11 Distribution's cost from Peoples TWP LLC is provided in PGC Exhibit No. 1, Schedule 3.
12 Peoples TWP LLC is the only physical source of supply for a small portion of Distribution's
13 system. In order to obtain other supplies Distribution would have to make a substantial
14 investment for the construction of new facilities to physically connect a few existing
15 customers to Distribution's other sources of supply. The customers referenced are located in
16 Butler County, at the extremity of Distribution's system. The category entitled "Exchange
17 Gas" on PGC Exhibit No. 1, Schedule 1, Sheet 1 reflects the recognition of gas costs related
18 to any monthly imbalances associated with two Exchange Agreements as discussed in PGC
19 Exhibit No. 8 and further explained in PGC Exhibit No. 4. The monthly breakdown of
20 Distribution's costs associated with Exchange Gas is provided in PGC Exhibit No. 1,
21 Schedule 1, Sheet 6.

22 The category entitled "Off-System Sales" on PGC Exhibit No. 1, Schedule 1, Sheet 1
23 reflects costs of gas purchased for sale to customers that are not part of Distribution's retail
24 system. Such purchases are removed from gas costs to properly reflect gas purchased to serve
25 Distribution's retail customers. The monthly breakdown of Distribution's gas costs associated
26 with Off-System Sales is provided in PGC Exhibit No. 1, Schedule 1, Sheet 7.

27 As stated in PGC Exhibit No. 8 and approved under previous settlements of
28 Distribution's 1307(f) proceedings, Distribution retains 25% of the net revenues from off-

DIRECT TESTIMONY OF NICHOLAS J. HEWA
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1 system sales. The remaining 75% of the net revenues are flowed through to ratepayers. The
2 category entitled "Off-System Sales Refund" on PGC Exhibit No. 1, Schedule 1, Sheet 1
3 reflects this 75% flow through of the net revenues. The monthly breakdown of Off-System
4 Sales Refunds is provided in PGC Exhibit No. 1, Schedule 1, Sheet 8.

5 The category entitled "Credit – Line Hits" on PGC Exhibit No. 1, Schedule 1, Sheet
6 1 reflects payments received by Distribution as compensation for gas lost as a result of
7 damage to Distribution's facilities. Generally, such payments are received from construction
8 contractors that cause damage to Distribution's facilities, typically during excavation projects.
9 A monthly breakdown of these amounts is provided in PGC Exhibit No. 1, Schedule 1, Sheet
10 5.

11 Q. Please explain PGC Exhibit No. 2 and PGC Exhibit No. 3.

12 A. PGC Exhibit No. 2 and PGC Exhibit No. 3 contain data pertaining to projected volumes and
13 costs of gas to be purchased by Distribution. PGC Exhibit No. 2 contains projected data, by
14 month, for gas to be purchased from suppliers during the period December 1, 2023 through
15 July 31, 2024. PGC Exhibit No. 3 contains projected data, by month, for gas to be purchased
16 from suppliers during the twelve-month period ending July 31, 2025.

17 Q. Please summarize how the projected data, contained in PGC Exhibit No. 2 and PGC Exhibit
18 No. 3, was prepared.

19 A. Based upon forecasted sales of gas explained by Mr. Harts, Distribution determined the total
20 volume of gas that Distribution would be required to purchase in order to make the projected
21 level of sales to its customers. Volumes of gas that Distribution would be able to obtain from
22 local producers and the small volume of gas to be purchased from Peoples TWP LLC were
23 projected. The remainder of gas supplies was projected to be purchased from upstream
24 suppliers.

25 PGC Exhibit No. 2, Schedule 1 and PGC Exhibit No. 3, Schedule 1 summarize the
26 projections of costs by category. PGC Exhibit No. 2, Schedule 1 summarizes projections for
27 the eight-month period ending July 31, 2024. PGC Exhibit No. 3, Schedule 1 summarizes
28 projections for the twelve-month period ending July 31, 2025.

1 The category entitled "Transportation Credit" on PGC Exhibit No. 2, Schedule 1
2 reflects revenues for recovery of purchased gas costs of transportation and storage expected
3 from transportation customers. The "Transportation Credit" reflected on Exhibit No. 3,
4 Schedule 1 is based upon the rate that is discussed in Mrs. Wesoloski's testimony. PGC
5 Exhibit No. 2, Schedule 1 summarizes such data for the eight-month period ending July 31,
6 2024. PGC Exhibit No. 3, Schedule 1 summarizes data for the twelve-month period ending
7 July 31, 2025.

8 PGC Exhibit No. 2, Schedule 2 and PGC Exhibit No. 3, Schedule 2 provide detailed
9 calculations of projected costs for upstream purchases and storage. PGC Exhibit No. 2,
10 Schedule 2 provides data for the eight-month period ending July 31, 2024. PGC Exhibit No.
11 3, Schedule 2 provides data for the twelve-month period ending July 31, 2025. The
12 projections of upstream supplier costs were explained previously in this testimony and the
13 wellhead price projection is explained in Mr. Harts' testimony.

14 PGC Exhibit No. 2, Schedule 3 and PGC Exhibit No. 3, Schedule 3 provide detail of
15 projected volumes and costs of gas to be purchased from Peoples TWP LLC. PGC Exhibit
16 No. 2, Schedule 3 provides such data for the eight-month period ending July 31, 2024 and
17 PGC Exhibit No. 3, Schedule 3 provides such data for the twelve month period ending July
18 31, 2025. These projections are based on historical amounts for the twelve months ended
19 November 30, 2023.

20 PGC Exhibit No. 2, Schedule 4 and PGC Exhibit No. 3, Schedule 4 provide the
21 amount of credits related to capacity release by month. PGC Exhibit No. 2, Schedule 4
22 provides data for the eight-month period ending July 31, 2024 and PGC Exhibit No. 3,
23 Schedule 4 provides data for the twelve month period ending July 31, 2025. The projection
24 of capacity release credits is explained in Mrs. Wesoloski's testimony.

25 PGC Exhibit No. 2, Schedule 5 and PGC Exhibit No. 3, Schedule 5 provide the
26 temperature swing/peaking capacity cost, which is the Demand-DC cost of gas. PGC Exhibit
27 No. 2, Schedule 5 provides data for the eight-month period ending July 31, 2024 and PGC
28 Exhibit No. 3, Schedule 5 provides data for the twelve month period ending July 31, 2025.

DIRECT TESTIMONY OF NICHOLAS J. HEWA
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1 Q. Please explain PGC Exhibit No. 21.

2 A. PGC Exhibit No. 21 is a computation of the projected cost of purchased gas that would be
3 included in rates effective August 1, 2024. This amount includes projected gas costs through
4 the end of the application period, July 31, 2025 and projected over/under collections through
5 July 31, 2024.

6 As indicated on PGC Exhibit No. 21, Schedule 1, Sheet 4, the total projected cost of
7 purchased gas per Mcf is \$5.9281. Of this amount, \$3.3112 per Mcf is the commodity cost
8 (including the "E" factor), and \$2.6169 per Mcf is the demand cost (including the "E" factor).

9 The cost of gas has been separated into four categories on PGC Exhibit No. 21,
10 Schedule 1, Sheet 4: the Natural Gas Supply Charge, the Gas Adjustment Charge, the
11 Distribution Charge, and the Total Gas Costs.

12 For gas supplied to all classes of retail customers (except those receiving service
13 under load balancing service and natural gas vehicle service rate schedules), the Natural Gas
14 Supply Charge is \$5.5335/Mcf. This represents an increase of \$.9259/Mcf from the Natural
15 Gas Supply Charge of \$4.6076/Mcf included in rates from November 1, 2023 through
16 January 31, 2024.

17 For gas supplied to all classes of retail customers (except those receiving service
18 under load balancing service and natural gas vehicle service rate schedules), the Gas
19 Adjustment Charge is (\$0.0479)/Mcf. This represents an increase of \$1.0634/Mcf compared
20 to the Gas Adjustment Charge of (\$1.1113)/Mcf included in rates from November 1, 2023
21 through January 31, 2024.

22 For gas supplied to all classes of retail customers (except those receiving service
23 under load balancing service and natural gas vehicle service rate schedules), the Distribution
24 Charge is \$0.4425/Mcf. This represents an increase of \$0.0631/Mcf compared to the
25 Distribution Charge of \$0.3794/Mcf included in rates from November 1, 2023 through
26 January 31, 2024.

27 In total, for gas supplied to all classes of customers (except those receiving service
28 under load balancing or natural gas vehicle service rate schedules), the projected cost of gas is

DIRECT TESTIMONY OF NICHOLAS J. HEWA
R-2024-3045177

1 \$5.9281 per Mcf. This represents an increase of \$2.0524 per Mcf from the amount of
2 \$3.8757 per Mcf included in rates from November 1, 2023 through January 31, 2024 for the
3 recovery of purchased gas costs.

4 The increase in rates for the recovery of purchased gas costs results from a number of
5 factors, including an increase in the “E” or experienced factor. As detailed on Exhibit NJH-
6 1, the current “E” factor reflected in rates as of November 1, 2023 is an overcollection of
7 \$23,687,952 (\$1.0928/Mcf).¹ The projected sales for passback of the “E” factor for the
8 period (Twelve Months Ended “TME” July 2024) are 21,708,981 Mcf for Commodity and
9 Demand-NGS and 23,651,935 Mcf for Demand-DC. As shown on PGC Exhibit No. 21,
10 Schedule 1, Sheets 1-3, Distribution projects, through July 31, 2025, an “E” factor
11 overcollection of \$1,020,384 (\$0.0469)/Mcf.² The projected sales for passback of the “E”
12 factor this period (TME July 2025) are 21,817,752 Mcf for Commodity and Demand-NGS
13 and 23,830,142 for Demand-DC. The projected undercollection produces an increase in rates
14 of \$1.0459/Mcf.³

15 The “C” factor rate increased. The current “C” factor reflected in rates as of
16 November 1, 2023 is \$108,555,079.⁴ The projected sales for the period (TME July 2024) are
17 21,708,981 Mcf for Commodity and Demand-NGS and 23,651,935 Mcf for Demand-DC. As
18 shown on PGC Exhibit No. 21, Schedule 1, Sheets 1-3, Distribution projects, through July 31,
19 2025, “C” factor costs of \$131,250,133.⁵ The projected sales for this period (TME July

¹ Commodity: \$26,097,749; \$1.2021 (Exhibit NJH-1, Page 1, Line 11) + Demand-NGS: (\$1,972,167); (\$0.0908) (Exhibit NJH-1, Page 2, Line 11) + Demand-DC: (\$437,630); (\$0.0185) (Exhibit NJH-1, Page 3, Line 11)

² Commodity: \$4,277,608 ÷ 21,817,752 Mcf = \$0.1961 per Mcf (Exhibit 21, Sch1, Pg1) + Demand-NGS: (\$3,233,172) ÷ 21,817,752 Mcf = (\$0.1482)/Mcf (Exhibit 21, Sch1, Sheet 2) + Demand-DC: (\$24,052) ÷ 23,830,142 Mcf = (\$0.0010)/Mcf (Exhibit 21, Sch1, Sheet 3)

³ Where rates \$1.0928/Mcf (“E” factor included in current rates) and (\$0.0469)/Mcf (“E” factor included in projected; then \$1.0928 – (\$0.0469) = \$1.0459/Mcf

⁴ \$108,555,079 = Commodity: \$60,009,393 (Exhibit NJH-1, Page 1, Line 3) + Demand-NGS: \$40,032,755 (Exhibit NJH-1, Page 2, Line 3) + Demand-DC: \$8,536,671 (Exhibit NJH-1, Page 3, Line 3) + Storage Int Commodity: (\$23,740) (Exhibit NJH-1, Page 4)

⁵ \$131,250,133 = \$76,803,656 (PGC Exhibit 21, Schedule 1, Sheet 1, Commodity) + \$44,207,399 (PGC Exhibit 21, Schedule 1, Sheet 2, Demand-NGS) + \$10,519,956 (PGC Exhibit 21, Schedule 1, Sheet 3, Demand-DC) + (\$280,878) (PGC Exhibit 21B, Sheet 2, Commodity - Storage).

DIRECT TESTIMONY OF NICHOLAS J. HEWA
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2025) are 21,817,752 Mcf for Commodity and Demand-NGS and 23,830,142 Mcf for Demand-DC. The change in the “C” factor results in an increase in rates of \$1.0065/Mcf.⁶ As shown on PGC Exhibit No. 21, Schedule 1, Sheet 1 this increase includes (\$0.0129)/Mcf for the passback of storage interest expense. The sum of the change in the “E” factor and the “C” factor represents a total increase of \$2.0524/Mcf [$(\$1.0459 + \$1.0065) = \$2.0524$].

PGC Exhibit No. 21, Schedules 2 through 11 explain the derivation of Distribution’s experienced over/under collection factor (“E” factor) used in PGC Exhibit No. 21, Schedule 1.

PGC Exhibit No. 21, Schedules 4 and 10 detail refunds, by component, received by Distribution, and these schedules also calculate interest on each refund. There were no refunds received during the twelve months ended November 30, 2023.

The information provided above was derived on the assumption that rates effective November 1, 2023, will remain in effect through July 31, 2024. In all likelihood, the quarterly filings for February 1 and May 1, 2024, will adjust rates. The amount of net adjustment, however, is not presently known.

Q. Please describe the methodology used to determine the interest rate that is applied to the over/undercollection of purchased gas costs and storage injections/withdrawals.

A. The interest rate to be applied to the over/undercollection of purchased gas costs and storage injections/withdrawals is based on Act 47 of Public Utility Code (66 PA. C.S.). Under this methodology, refunds to customers shall be made with and recoveries from customers shall include interest at the prime rate for commercial borrowing in effect 60 days prior to the tariff filing and as reported in a publicly available source identified by the Commission or at an interest rate which may be established by the Commission by regulation.

Q. Please describe PGC Exhibit No. 21A.

6

\$5.9750 (PGC 2024) less \$4.9685 (PGC 2023 November 1) = \$1.0065/Mcf. Where \$5.9750/Mcf (“C” factor in projected rates) = $(\$76,803,656 \div 21,817,752) + (\$44,207,399 \div 21,817,752 \text{ Mcf}) + (\$10,519,956 \div 23,830,142 \text{ Mcf})$ or $\$5.9879/\text{Mcf} + (\$0.0129)/\text{Mcf}$; and $\$4.9685/\text{Mcf}$ (“C” factor in current rates) = (Commodity: $\$2.7643/\text{Mcf}$ Exhibit NJH-1, Page 1, Line 7) + (Demand-NGS: $\$1.8440/\text{Mcf}$ Exhibit NJH-1, Page 2, Line 7) + (Demand-DC: $\$0.3609/\text{Mcf}$ Exhibit NJH-1, Page 3, Line 7) + (Storage Commodity: $\$0.0007/\text{Mcf}$ Exhibit NJH-1, Page 4)

DIRECT TESTIMONY OF NICHOLAS J. HEWA
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1 A. PGC Exhibit No. 21A is the Statement of Over/Undercollections for the twelve months ended
2 November 30, 2023. The exhibit provides separate detail for the Commodity, Demand–NGS
3 and Demand–DC components of purchased gas costs, and the exhibit is self-explanatory.

4 Q. Please explain the purpose of PGC Exhibit No. 21B.

5 A. PGC Exhibit No. 21B is a calculation of interest on storage injections and withdrawals. Sheet
6 1 shows the twelve months ending July 31, 2024, and Sheet 2 shows the twelve months
7 ending July 31, 2025.

8 For base rate purposes, Distribution has valued gas in storage at its average inventory
9 cost. That is, withdrawals from and injections into storage are priced at the average cost of all
10 gas in storage at the beginning of the gas storage cycle. However, for purchased gas cost
11 purposes, Distribution uses the last-in, first-out ("LIFO") method. The LIFO method prices
12 withdrawals and injections at the average cost of all gas purchases for the current year. The
13 LIFO method is appropriate for gas cost purposes because it recognizes that current purchases
14 of gas are used to serve current requirements and that storage withdrawals used to serve peak
15 requirements are only short term and are refilled every year.

16 Over a normal twelve-month period, withdrawals and injections will be equivalent,
17 and thus the beginning and ending storage balances under the two methods will be the same.
18 However, Distribution recognizes that there is a time value of money component to pricing
19 storage gas at the average inventory cost, for working capital purposes in base rates. For
20 example, in a winter month, Distribution will be using storage having an inventory value of
21 \$1.1915 per Mcf to serve peak requirements, and will charge customers a higher, fiscal year
22 rate of \$5.6139 per Mcf for such gas. Conversely, in a summer month, Distribution will refill
23 storage using purchases priced at \$5.6139 per Mcf, but the inventory value of these injections
24 will be the lower \$1.1915 per Mcf average inventory rate.

25 In order to recognize time value of money differences in this 1307(f) proceeding,
26 interest is calculated on storage injections and withdrawals based upon the rate differential
27 between the storage rate and the inventory rate on a fiscal year basis.

28 Q. Please summarize the calculation of interest shown on PGC Exhibit No. 21B.

DIRECT TESTIMONY OF NICHOLAS J. HEWA
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1 A. PGC Exhibit No. 21B, Sheets 1 and 2 show the interest calculation for the twelve months
2 ending July 31, 2024, and July 31, 2025, respectively. This calculation projects the estimated
3 interest to be incurred during the indicated PGC period. The calculation, as detailed below,
4 allows for immediate passback or recovery based on a uniform amount per Mcf during the
5 current twelve-month PGC period in which expense or income arises. This methodology, as
6 approved per the order at Docket No. R-2010-2150861, matches the occurrence of income or
7 expense with the reflection of such income or expense in rates. In addition, this methodology
8 allows for quarterly updates to the estimated interest, based on actual information, through the
9 C-Factor gas cost recovery mechanism.

10 The net interest income in the amount of \$12,081 on PGC Exhibit No. 21B, Sheet 1
11 flows to PGC Exhibit No. 21, Schedule 11, Sheet 4. This amount is compared to the total
12 estimated interest income to be recovered during the twelve months ending July 31, 2024
13 through the C-Factor. The difference represents the estimated amount that will be included in
14 the E-Factor for the twelve months ending July 31, 2024.

15 PGC Exhibit No. 21B, Sheet 2 shows the interest calculation for the twelve months
16 ending July 31, 2025. The calculation shows an estimated net interest expense in the amount
17 of \$280,878. This amount is projected to be passed back during the rate application period in
18 which it occurs, which is the twelve months ending July 31, 2025. As shown on Sheet 2, the
19 net interest expense of \$280,878 will be passed back at a rate of (\$0.0129) per Mcf, included
20 in the C-Factor on PGC Exhibit No. 21, Schedule 1, Sheet 1.

21 Q. Please explain the calculation of interest shown on PGC Exhibit No. 21B, Sheet 2.

22 A. The schedule identifies months with estimated or actual data as open or closed periods.
23 Columns 1 and 2 show storage injections and withdrawals. Column 3 shows the rate
24 differential which represents the difference between the storage inventory rate included in
25 base rates calculated on an average cost method and the inventory rate charged through the
26 1307(f) gas cost recovery mechanism based on the LIFO valuation method.

27 Storage injections represent decreases to purchased gas expense as theoretically a
28 portion of volumes purchased and paid by Distribution exceeding the current requirements.

DIRECT TESTIMONY OF NICHOLAS J. HEWA
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1 The Cost Paid by Distribution but not Charged through the PGC, Column 5, is calculated by
2 multiplying the injections (column 1) by the rate differential (column 3). These costs result
3 in interest income to be recovered from the ratepayer, as they will not be charged through
4 purchased gas costs until the gas is withdrawn. Storage withdrawals represent increases to
5 purchased gas expense, as theoretically requirements exceed current purchases. The Cost
6 Charged through the PGC but not Paid by Distribution, Column 4, is calculated by
7 multiplying the withdrawals (column 2) by the rate differential (column 3). These costs result
8 in interest expense to be passed back to the ratepayer, as they are charged through purchased
9 gas costs when the gas is withdrawn, but were paid by Distribution when the gas was
10 injected. Storage Net Paid/Net Charged in Column 6 is the sum of columns 4 and 5.

11 The Interest Weight (column 7) represents the ratio of the twelve-month PGC period
12 the interest is expected to be outstanding. The Interest Rate (column 8) represents the
13 statutory rate to be charged for interest based on the estimated net over/undercollection of
14 associated storage costs for the twelve months ended July. Column 9 represents the
15 calculation of gross storage interest expense or interest income. This is calculated by
16 multiplying the Storage Net Paid/Net Charged (column 6) by the applicable prorated interest
17 rate (column 7 x column 8). The sum of the monthly values in column 9 (Gross Storage
18 Interest Expense/Revenue) represents the amount of storage interest expense/income due
19 to/from ratepayers.

20 Q. Please explain PGC Exhibit No. 21C.

21 A. PGC Exhibit No. 21C, provides the “Explanation that Over/Undercollections for the Twelve
22 Months Ended November 30, 2023, resulted from a Least-Cost Procurement Policy”, which
23 is a statement that is required to be filed with the Commission pursuant to their regulation at
24 52 Pa. Code Section 53.64(i). The exhibit is self-explanatory.

25 Q. Does this conclude your direct testimony?

26 A. Yes, it does at this time.

Verification

I, Nicholas Hewa, Rate Analyst II, of the Rates and Regulatory Affairs Department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 5 Direct Testimony of Nicholas Hewa
Exhibit Nos. 1, 2, 3, 21, 21-A, 21-B, 21-C, and NJH-1

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

Nicholas Hewa

Nicholas J. Hewa

This 31st day of January, 2024

REBUTTAL TESTIMONY OF
NICHOLAS J. HEWA
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024-3045177

REBUTTAL TESTIMONY OF NICHOLAS J. HEWA
R-2024-3045177

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

2 A. My name is Nicholas Joseph Hewa, and my business address is 6363 Main Street,
3 Williamsville, New York 14221.

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

5 A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or the
6 "Company") as a Rate Analyst II in the Rates and Regulatory Affairs Department.

7 **Q. Have you testified previously in this proceeding?**

8 A. Yes, I sponsored Distribution's Statement No. 5 that was included in the materials filed by
9 Distribution on January 31, 2024.

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

11 A. The purpose of my rebuttal testimony is to address the recommendations raised by the Office
12 of Consumer Advocate's ("OCA") witness Mr. Mierzwa regarding audit findings that will result
13 in the refund of \$111,398 to Distribution's PGC customers. These findings were made during
14 a purchased gas cost audit conducted by the Pennsylvania Public Utility Commission's
15 ("Commission") Bureau of Audits at Docket No. D-2022-3031418, and include the
16 implementation of controls to help prevent, detect, and correct preventable errors in future
17 PGC filings made by Distribution.

18 **Q. Please provide some brief background information regarding the refund to PGC
19 customers of \$111,398.**

20 A. The purchased gas cost audit conducted by the Bureau of Audits in Docket No. D-2022-
21 3031418 found that Distribution should refund \$111,398 to its PGC customers. This refund is
22 attributable to findings in the reporting of prior period adjustments and amortization of
23 over/under collection balances during the December 2017 – November 2020 audit period.
24 The impact of the finding in the reporting of prior period adjustments resulted in \$124,700 of
25 interest still owed to PGC customers. The finding in the amortization of over/under collection
26 balances during the December 2017 – November 2020 audit period resulted in Distribution

REBUTTAL TESTIMONY OF NICHOLAS J. HEWA
R-2024-3045177

1 over refunding \$13,302 to its PGC customers. These two findings result in a net refund of
2 \$111,398 still owed to PGC customers.

3 **Q. Please summarize Mr. Mierzwa's recommendation regarding the refund to PGC**
4 **customers of \$111,398.**

5 A. Mr. Mierzwa recommends that Distribution should refund the \$111,398 to its PGC
6 customers in its May 2024 quarterly PGC filing.

7 **Q. Do you agree with Mr. Mierzwa's recommendation for Distribution to refund \$111,398**
8 **to its PGC customers in its May 2024 quarterly PGC filing?**

9 A. No, I do not agree with Mr. Mierzwa's recommendation. I propose that Distribution refund the
10 \$111,398 to its PGC customers in its August 1, 2024 PGC24 compliance filing ("August
11 Compliance Filing") instead of its May 1, 2024 quarterly filing ("May Quarterly Filing").

12 **Q. Why are you proposing for Distribution to refund the \$111,398 to its PGC customers in**
13 **its August Compliance Filing instead of its May Quarterly Filing?**

14 A. The Bureau of Audits report on Distribution's Statements of Purchased Gas Cost for the
15 audit period of December 2017 – November 2020 recommends that Distribution adjust for
16 these findings in "its next PGC filing." Distribution interprets this as its next annual filing,
17 which would be its August Compliance Filing, not its May Quarterly Filing. The E-factor
18 period of August 2022 – July 2023 for the Company's PGC23 period and reflected in the May
19 Quarterly Filing has already been established. Any changes reflected in the May Quarterly
20 Filing would be administratively burdensome and unnecessarily complicate the reconciliation
21 of E-factor amounts established in PGC23.

22 **Q. Please summarize Mr. Mierzwa's recommendation regarding the implementation of**
23 **controls by Distribution regarding its PGC filings.**

24 A. Mr. Mierzwa recommends that Distribution evaluate and implement controls to help prevent,
25 detect, and correct preventable errors in its future PGC filings, such as the findings that led
26 to the required refund of \$111,398 found by the Bureau of Audits explained above. Mr.

REBUTTAL TESTIMONY OF NICHOLAS J. HEWA
R-2024-3045177

1 Mierzwa also recommends that Distribution identify and report the implementation of such
2 controls in its annual PGC filing next year.

3 **Q. Do you agree with Mr. Mierzwa's recommendation for Distribution to implement**
4 **controls and to identify and report these controls in its annual PGC filing next year?**

5 A. Yes, I agree with Mr. Mierzwa's recommendation. Distribution is currently in the process of
6 evaluating and implementing such controls. Distribution will identify and report these controls
7 in its annual PGC filing next year.

8 **Q. Does this conclude your testimony?**

9 A. Yes, at this time.

Verification

I, Nicholas Hewa, Rate Analyst II, of the Rates and Regulatory Affairs department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 5R Rebuttal Testimony of Nicholas Hewa

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

Nicholas Hewa

Nicholas Hewa

This 22nd day of March, 2024

**PENNSYLVANIA PUBLIC UTILITY COMMISSION
BUREAU OF AUDITS**



**REPORT ON
NATIONAL FUEL GAS
DISTRIBUTION CORPORATION**

**STATEMENTS OF
PURCHASED GAS COST
DECEMBER 1, 2017 — NOVEMBER 30, 2020**

**DECEMBER 21, 2023
DOCKET NO. D-2022-3031418**

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Background

National Fuel Gas Distribution Corporation (NFG or company) is a wholly owned subsidiary of National Fuel Gas Company, which sells and transports natural gas to customers in New York and Pennsylvania. The company is headquartered in Williamsville, New York, with a divisional office in Erie, Pennsylvania. NFG serves about 214,000 customers across 15 counties in northwestern and northcentral Pennsylvania, with the largest concentration of customers located in Erie County. According to the annual reports filed with the Pennsylvania Public Utility Commission (PUC or Commission) for the years 2020, 2019, and 2018, NFG's total sales and transportation revenues were \$190,297,187; \$211,688,094; and \$219,201,997; respectively.



COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
COMMONWEALTH KEYSTONE BUILDING
400 NORTH STREET
HARRISBURG, PENNSYLVANIA 17120

Independent Auditor's Report to the Pennsylvania Public Utility Commission

Report on the Financial Statements

We have audited National Fuel Gas Distribution Corporation's Statements of Purchased Gas Cost for the 12-month periods ended November 30, 2020, November 30, 2019, and November 30, 2018.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether these statements are free from material misstatement. An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in these statements. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of these statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of these statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of these statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Purchased Gas Cost Statements, referred to above, present fairly, in all material respects, the Purchased Gas Cost revenue and expenses of National Fuel Gas Distribution Corporation as of November 30, 2020, November 30, 2019, and November 30, 2018 in conformity with accounting principles generally accepted in the United States of America and the requirements of the Pennsylvania Public Utility Commission.

Report on Other Legal and Regulatory Requirements

The accompanying statements were prepared for the purpose of complying with the rules and regulations of the Pennsylvania Public Utility Commission and are not intended to be a complete presentation of National Fuel Gas Distribution Corporation's revenue and expenses.

Kelly Monaghan, CPA

Kelly A. Monaghan, CPA, CGFM, CFE, CISA
Director
Bureau of Audits
Harrisburg, PA
December 21, 2023

National Fuel Gas Distribution Corporation
Purchased Gas Cost¹ (PGC)
Over/(Under) Collections (Section 1307(f))
for the 12 months ended November 30, 2020²

Month	PGC Revenue	Cost of Fuel	Over/(Under) Collections
	(1)	(2)	(3) = (1) – (2)
December 2019	\$ 10,454,913	\$ 10,408,011	\$ 46,902
January 2020	11,503,815	13,194,201	(1,690,386)
February	11,926,764	12,953,547	(1,026,783)
March	10,601,755	10,037,936	563,819
April	8,188,973	3,388,072	4,800,901
May	6,180,608	2,031,447	4,149,161
June	2,316,642	580,799	1,735,843
July	1,265,200	818,648	446,552
August	1,317,824	1,741,206	(423,382)
September	1,575,963	1,258,710	317,253
October	3,097,457	2,235,049	862,408
November	<u>5,709,417</u>	<u>8,881,300</u>	<u>(3,171,883)</u>
Total	<u>\$ 74,139,331</u>	<u>\$ 67,528,926</u>	<u>\$ 6,610,405</u>

¹ As reported to the Commission at Docket No. R-2021-3023541. Arithmetic differences are due to rounding.

² Notes to the Financial Statements are an integral part of this report.

National Fuel Gas Distribution Corporation
Purchased Gas Cost³ (PGC)
Over/(Under) Collections (Section 1307(f))
for the 12 months ended November 30, 2019⁴

Month	PGC Revenue	Cost of Fuel	Over/(Under) Collections
	(1)	(2)	(3) = (1) – (2)
December 2018	\$ 13,916,260	\$ 15,045,229	\$ (1,128,969)
January 2019	15,517,013	20,403,491	(4,886,478)
February	17,812,584	16,088,605	1,723,979
March	16,853,800	14,504,534	2,349,266
April	11,052,379	4,147,336	6,905,043
May	6,491,753	1,655,632	4,836,121
June	2,594,113	1,623,798	970,315
July	1,537,699	528,751	1,008,948
August	1,430,603	(716,213)	2,146,816
September	1,403,056	1,146,952	256,104
October	2,079,745	2,966,254	(886,509)
November	6,109,509	10,555,659	(4,446,150)
Total	<u>\$ 96,798,514</u>	<u>\$ 87,950,028</u>	<u>\$ 8,848,486</u>

³ As reported to the Commission at Docket No. R-2020-3015251. Arithmetic differences are due to rounding.

⁴ Notes to the Financial Statements are an integral part of this report.

National Fuel Gas Distribution Corporation
Purchased Gas Cost⁵ (PGC)
Over/(Under) Collections (Section 1307(f))
for the 12 months ended November 30, 2018⁶

<u>Month</u>	<u>PGC Revenue</u> (1)	<u>Cost of Fuel</u> (2)	<u>Over/(Under) Collections</u> (3) = (1) – (2)
December 2017	\$ 12,212,122	\$ 14,690,403	\$ (2,478,281)
January 2018	19,128,865	18,717,094	411,771
February	15,749,605	14,491,688	1,257,917
March	12,935,022	15,070,939	(2,135,917)
April	12,619,832	8,441,984	4,177,848
May	6,260,952	1,824,450	4,436,502
June	2,184,359	360,847	1,823,512
July	1,563,193	1,608,311	(45,118)
August	3,027,851	2,373,470	654,381
September	84,324	2,294,483	(2,210,159)
October	2,608,264	5,724,554	(3,116,290)
November	<u>7,892,436</u>	<u>14,702,273</u>	<u>(6,809,837)</u>
Total	<u>\$ 96,266,825</u>	<u>\$ 100,300,496</u>	<u>\$ (4,033,671)</u>

⁵ As reported to the Commission at Docket No. R-2019-3006858. Arithmetic differences are due to rounding.

⁶ Notes to the Financial Statements are an integral part of this report.

Notes to the Financial Statements

1 – Statements

The Purchased Gas Cost (PGC) Over/(Under) Collections presented in this report are condensed from the officially filed statements. The audit was conducted on NFG's officially filed 1307(f) statements submitted to the PUC in accordance with Section 1307(f)(3) of the Public Utility Code on December 31, 2020, December 30, 2019, and July 31, 2019. The statements are available on the PUC's website (<http://www.puc.pa.gov>) at Docket Nos. R-2021-3023541, R-2020-3015251, and R-2019-3006858.

2 – PGC Revenue

The PGC Revenue is calculated by multiplying the appropriate commodity, NGS and demand volumes billed during the month by the applicable PGC rates, excluding E-Factor. The PGC Revenue also reflects accounting adjustments in accordance with National Fuel's PGC Rider.

3 – Cost of Fuel

The Cost of Fuel is the purchased gas commodity and demand costs incurred by the company to service customers pursuant to all rate schedules of the company's tariff with some exclusions as defined in the company's PGC Rider.

4 – Over/(Under) Collections

The Over/(Under) Collection is the difference between the PGC Revenue and the Cost of Fuel. The resulting amount represents the portion of PGC Revenue refundable to or Cost of Fuel recoverable from customers through subsequent PGC rates. Differences arise for two primary reasons:

- Variations between the actual volumes billed to customers and the estimates used to determine the PGC rates; and,
- Variations between actual Cost of Fuel and the estimates used to determine the PGC rates.

Disposition of Prior Audit Findings

Our previous audit of National Fuel's PGC for the 12-month periods ended November 30, 2017 and November 30, 2016, at Docket No. D-2019-3010083, disclosed the following findings:

Finding No. 1 – NFG improperly allocated capacity release credits.

Recommendation:

We recommended that NFG refund \$1,369,080 plus applicable interest through an adjustment to the E-Factor of its next PGC filing.

Disposition:

NFG improperly refunded \$1,369,080 through current period costs rather than through the E-Factor and did not refund the full interest amount. See Finding No. 1 of Current Audit Findings.

Finding No. 2 – NFG applied an incorrect interest rate to over/under collections.

Recommendation:

We recommended that NFG recover \$29,653 through an adjustment to the E-Factor of its next PGC filing.

Disposition:

NFG recovered \$29,653 from its customers through the PGC rate effective August 1, 2020, at Docket No. R-2020-3015251.

Current Audit Findings

Finding No. 1 – NFG improperly adjusted for a prior audit finding.

Finding No. 1 in our prior audit report included the recommendation that the company make an adjustment to refund \$1,369,080, plus applicable interest, through the E-Factor of its next PGC filing. Any adjustment for a prior period should be reported in the E-Factor. The company did not make an adjustment to its E-Factor for that amount. Instead, the company included the adjustment in current period gas costs for July 2019. Including a prior period adjustment in current period activity results in misstated current period over/under collections, and interest. In this case, NFG over refunded interest by \$97,547.

Regarding interest on the finding recommendation, the company included \$72,343 in the E-Factor of the PGC rates effective August 1, 2020 at Docket No. R-2020-3015251. The company calculated interest based on the methodology for annual reconciliation. The appropriate method should have been based on the number of months it took to refund the money to its customers. As a result, the amount of interest was insufficient. Audit staff calculated interest to be \$294,590.

Calculated interest	\$294,590
Over-refunded interest	97,547
Included in E-Factor	<u>72,343</u>
Total Due Ratepayers	<u>\$124,700</u>

After accounting for the over-refund of interest for the current period and the interest adjustment included in the E-Factor, NFG still owes interest in the amount of \$124,700 to its customers.

Recommendations:

We recommend that NFG refund \$124,700 through an adjustment to the E-Factor of its next PGC filing. We also recommend that NFG implement controls to prevent errors in reporting prior period adjustments.

Current Audit Findings (continued)

Finding No. 2 – NFG miscalculated the over/under collection balances by \$13,302.

NFG miscalculated the over/under collection balances by carrying forward incorrect balances as of August 1, 2019 and November 1, 2019, and as of August 1, 2020 and November 1, 2020. This resulted in the company over refunding \$8,884 in 2019 and \$4,418 in 2020, totaling \$13,302.

Recommendations:

We recommend that NFG recoup \$13,302 from its customers through an adjustment to the E-Factor of its next PGC filing. We also recommend that NFG implement controls to prevent, detect, and correct errors within the spreadsheets used for amortizing over/under balances.

Acknowledgement

We wish to express our appreciation to the officers and staff of National Fuel Gas Distribution Corporation for their cooperation and assistance. The audit was conducted by Derek Vandevort, assisted by Jenny Kalna and Jacob Fultz.

TESTIMONY OF
TRACY L. WESOLOSKI
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024-3045177

DIRECT TESTIMONY OF TRACY L. WESOLOSKI
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1 Q. Please state your name and business address.

2 A. My name is Tracy L. Wesoloski and my business address
3 is 6363 Main Street, Williamsville, New York 14221.

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

5 A. I am employed by National Fuel Gas Distribution
6 Corporation ("Distribution" or the "Company") as an
7 Assistant Manager in the Rates and Regulatory Affairs
8 Department.

9 Q. What is your educational background and experience?

10 A. I received a Bachelor of Science Degree in Finance and
11 Economics from Canisius College in May 2003. I
12 received a Masters of Business Administration from the
13 University at Buffalo in December 2009. Prior to
14 joining the Rates and Regulatory Affairs department in
15 March 2022, I worked in the Finance department at the
16 Company for 17 years.

17 Q. What is the purpose of your testimony?

18 A. I am testifying in support of PGC Exhibit Nos. 2
19 (Partial), 3 (Partial), 13, 13A, 17, 23, 24, 24A, 28,
20 29, 33 and 34. I will also provide a general
21 description of the Company's rates for recovery of
22 purchased gas costs charged to transportation
23 customers.

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1 Q. Please explain PGC Exhibit 2, Schedule 4 and PGC
2 Exhibit No. 3, Schedule 4.

3 A. PGC Exhibit No. 2, Schedule 4 reflects a projection of
4 the value of capacity releases of \$2,622,958 for the
5 link period, the eight months ending July 31, 2024.
6 PGC Exhibit No. 3, Schedule 4 reflects a projection of
7 \$6,904,343 for the rate year period, the twelve months
8 ending July 31, 2025. These values include releases
9 by Distribution as part of its Enhanced Firm
10 Transportation ("EFT") transportation and Enhanced
11 Storage Service ("ESS") storage entitlements on Supply
12 to the Small Aggregation Transportation Supplier
13 ("SATS") Service marketers, as well as releases to
14 others. The total value of such capacity released to
15 the SATS marketers is projected to be \$1,343,187 for
16 the link period and \$5,103,825 for the rate period.

17 Q. Please explain the rate structure changes included in
18 PGC Exhibit No. 13.

19 A. Distribution has implemented a system-wide customer
20 choice program in compliance with the Natural Gas
21 Choice and Competition Act ("Act") (66 Pa. CS. §§
22 2201-12). This program provides an opportunity to all
23 of Distribution's small volume customers (except those
24 served under the Low-Income Residential Assistance

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1 Rate Schedule) for aggregated transportation services.

2 Under Distribution's system-wide choice program,
3 qualified natural gas suppliers ("NGSs") are able to
4 serve the aggregated gas supply requirements of their
5 customers. Customers receive transportation service
6 under Distribution's Small Aggregation Transportation
7 Customer Service Rate Schedule ("Rate Schedule SATC").
8 NGSs are required to qualify for service under SATS.

9 Under the SATS tariff, Distribution is the
10 Supplier of Last Resort ("SOLR"). Distribution
11 retains upstream capacity necessary for operational
12 purposes. Distribution releases to NGSs sufficient
13 pipeline capacity to meet the requirements of
14 customers that have chosen to be served by the NGSs.

15 The total capacity requirements of the NGSs are
16 calculated based on 62 heating degree days during the
17 rate year. The 62-degree day factor was determined by
18 deducting the 12 degree days associated with capacity
19 retained for temperature swing/peaking from the
20 extreme design peak day degree day level of 74 degree
21 days. The costs of retained capacity are recovered
22 from NGSs through SATC rates.

23 Q. Are the gas costs incurred to provide this service
24 reflected in this filing?

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1 A. Yes, the proposed SATS and SATC rates provide for
2 recovery of gas costs incurred to support the system-
3 wide customer choice service. Distribution has
4 retained a portion of storage capacity and associated
5 transmission capacity based on 12 degree days for its
6 small volume aggregation customers. The capacity is
7 needed for all small volume customers regardless of
8 whether the customers receive service under a
9 Distribution tariff sales rate schedule or receive gas
10 supply service from another supplier. The capacity
11 retained and included in the SATC rate includes a
12 portion of the EFT capacity from National Fuel Gas
13 Supply Corporation ("Supply"). Because the retained
14 capacity is required by both sales and SATC customers,
15 the costs of capacity are recovered through both sales
16 and SATC customer delivery rates.

17 Q. Has Distribution proposed to modify the mix of
18 capacity allocated to SATS service based on capacity
19 changes anticipated in the rate year?

20 A. Yes. The allocation projections effective for the rate
21 year are as follows:

22 Percent of Peak Day

23

24 Met by Upstream Capacity

Capacity

25

26 1. 55%

Supply storage and

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1 associated transmission
2 released to NGSSs

3
4 2. 45% Mandatory release of
5 upstream capacity

6
7 3. 0% Capacity retained by
8 Distribution and
9 included in SATC rates

10
11 Q. Do the rates proposed by Distribution in this
12 proceeding reflect the system-wide customer choice
13 program?

14 A. Yes. The rates filed by Distribution in this
15 proceeding are consistent with Distribution's system-
16 wide customer choice program under the Act.

17 Q. What amount is included in SATC rates for the recovery
18 of such retained capacity?

19 A. PGC Exhibit No. 13A provides the calculation of the
20 distribution charge demand cost rates ("Demand-DC
21 rates") for SATC service on or after August 1, 2024.
22 PGC Exhibit No. 13A provides the calculation of the
23 Demand-DC rate included in SATC rates of \$0.4415 per
24 Mcf. The pipeline demand rates summarized on PGC
25 Exhibit No. 13A are the costs of upstream pipeline
26 capacity retained by Distribution in order to preserve
27 reliability and for the management of temperature
28 swing/peaking requirements based upon 12-degree days.

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1 The EFT Capacity and ESS Delivery and Capacity
2 includes an allocated amount of contingency capacity.
3 The total Demand-DC charge included in SATC rates
4 reflects an amount associated with under collected gas
5 costs from previous periods. PGC Exhibit 21, Schedule
6 1, Sheet 3 provides total demand cost of gas recovered
7 through SATC rates of \$0.4415 per Mcf.

8 Q. Please provide a general description of the Company's
9 rates charged to customers to recover purchased gas
10 costs.

11 A. The Company recovers its purchased gas costs through
12 the purchase gas cost rates it charges sales and
13 transportation customers. Total purchase gas costs
14 projected to be incurred for the twelve months ending
15 July 2025 are forecasted. Projected sales and
16 transportation volumes for the twelve months ending
17 July 2025 are used to determine forecasted gas costs.
18 For purposes of the forecast of sales and
19 transportation total requirements, a system wide lost
20 and unaccounted for ("LAUF") gas factor is used. The
21 calculations for LAUF are shown in Exhibit 27. The
22 portion of purchased gas costs incurred to support
23 transportation services is assigned to transportation

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1 service rates with the remaining purchase gas costs
2 recovered through rates to sales customers.

3 Historic purchase gas costs for the twelve months
4 ending July 2024 are reconciled with purchase gas cost
5 revenues from sales and transportation customers for
6 the twelve months ending July 2024. Any over or under
7 collection of purchased gas costs is either credited
8 or surcharged to sales customers through the gas
9 adjustment charge ("GAC") rate included in purchased
10 gas cost rates.

11 Q. Please explain PGC Exhibit No. 17.

12 A. PGC Exhibit No. 17 compares Distribution's average
13 transportation and storage costs from its affiliates
14 to non-affiliates located upstream for the twelve
15 months ended ("TME") November 30, 2023.

16 Q. How does the Pennsylvania Division's affiliated
17 average cost of transportation services compare with
18 others?

19 A. As shown in PGC Exhibit No. 17, Page 2, Distribution's
20 average transportation costs from Supply are higher
21 costs than Columbia Gas Transmission LLC ("Columbia"),
22 Tennessee Gas Pipeline Company ("TGP" or "Tennessee")
23 and Texas Eastern Transmission, LP ("TETCO" or "Texas
24 Eastern"). Transportation services by the interstate

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1 pipelines upstream of Supply are not interchangeable
2 with transportation service provided by Supply.
3 Specifically, Supply provides the benefit of a
4 multiple point system that distributes the gas from
5 the applicable upstream pipeline receipt points to
6 Distribution's many local distribution systems that in
7 turn deliver gas to end-user customers.

8 Q. What is the benefit of using Supply's storage service?

9 A. Supply provides the no-notice storage service that is
10 critical for meeting Distribution's temperature
11 sensitive demand. It also allows for overrun service
12 from time to time and offers a more flexible
13 injection/withdrawal operation than the storage
14 services provided by other upstream pipelines.

15 Q. Does the cost comparison in PGC Exhibit No. 17, Page 3
16 represent all the costs associated with storage
17 services?

18 A. No. The comparison does not represent all the costs
19 incurred when Distribution contracts for storage
20 capacity with upstream pipelines. In reality, most
21 storage agreements require Distribution to sign up
22 specific transportation service to move gas into and
23 from the storage field. This additional storage
24 transportation cost is incremental and should be

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1 factored in the storage cost comparison. In contrast,
2 Supply's storage service is more economical because
3 Distribution contracts with Supply only for sufficient
4 transportation service to meet customers' peak day and
5 seasonal requirements. No additional transportation
6 capacity is required to use Supply's storage.

7 Q. Please briefly explain PGC Exhibit No. 23.

8 A. PGC Exhibit No. 23 has three schedules, which contain
9 Distribution's projected purchased gas cost portfolio.
10 The schedules are:

- 11 • Schedule 1:
 - 12 ° Projected upstream transportation volumes at
 - 13 Distribution - Pennsylvania Distribution {"PAD"})'s
 - 14 citygate (pages 1-2).
 - 15 ° Upstream transportation service tariff rates
 - 16 (pages 3-4)
 - 17 ° Storage and purchased gas costs (pages 5-6).
 - 18 ° Storage volumes (pages 7-8).
 - 19 ° Summary of storage unit costs (pages 9-10).
 - 20 ° Storage costs (pages 11-12).
 - 21 ° Storage unit costs (pages 13-14).
- 22 • Schedule 2: Distribution - PAD's Appalachian and
- 23 local production gas cost calculation.

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1 • Schedule 3: Upstream pipeline contracted capacity
2 and rates.

3 Q. How is the projected purchased gas portfolio
4 generated?

5 A. The projected purchased gas portfolio, in terms of
6 receipt and delivered volumes, is generated from the
7 ABB SENDOUT™ model ("Sendout").

8 Q. Please briefly describe the SENDOUT™ model.

9 A. The Gas Supply Administration Department uses Sendout,
10 a least cost, linear programming optimization model to
11 facilitate its long-term (1-5 years) and short-term
12 (monthly and seasonal) forecasting contract
13 optimization. Sendout is used to project purchase,
14 storage use, pipeline use and total system
15 costs. Various inputs into the Sendout model are used
16 to develop the plan. Pipeline, storage and gas
17 purchase contractual provisions are
18 considered. Inputs include: maximum daily quantities
19 ("MDQ"), minimum takes, maximum takes, seasonal
20 quantities, receipt zones, market pricing, demand
21 quantities and demand rates. Market pricing is
22 estimated using wellhead prices, provided by the Rates
23 and Regulatory Affairs Department, for the relevant

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1 month being modeled and a basis differential for
2 relevant purchase points.

3 Q. How is the gas cost in PGC Exhibit No. 23, Schedule 1,
4 Pages 5 and 6 calculated?

5 A. With a few exceptions, the gas cost is calculated by
6 multiplying the receipt volume in PGC Exhibit No. 23,
7 Schedule 1, Pages 1 and 2 by the projected wellhead
8 price in PGC Exhibit No. 25. The forecasted basis is
9 also applied to the receipt volume and the basis
10 applied is dependent upon the receipt and delivery
11 points. The exceptions are, as discussed in PGC
12 Exhibit No. 8, Distribution's contracts for some gas
13 supplies with fixed prices or limited price
14 escalations to be delivered during the period December
15 2024 through March 2025. These gas supplies are
16 individually priced in accordance with their
17 negotiated agreements. The gas costs presented on PGC
18 Exhibit No. 23 reflect these exceptions.

19 Q. What are the sources of the upstream pipeline rates in
20 PGC Exhibit No. 23, Schedule 1, Pages 3, 4, 9 and 10?

21 A. The rates are derived from the latest tariff filings.
22 The specifics of each pipeline are discussed below:

23 • Columbia: The current rates, which were taken
24 from Docket Nos. RP24-121-000 Operational

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Transactions Rate Adjustment Filing and RP22-633-000 Annual Retainage Adjustment Mechanism Filing, are assumed to remain in effect throughout the projection period.

- Tennessee: The current rates, which were taken from Docket Nos. RP24-102 and RP23-1103-000, are assumed to be in effect throughout the projection period.

- Supply: The current proposed rates, which were taken from Docket No. RP23-929-000, are assumed to be in effect throughout the projection period and subject to refund upon Rate Filing settlement.

- Texas Eastern: The current rates, which were taken from Docket Nos. RP24-102-000 Annual ASA and Interruptible Revenue Reconciliation Report, and RP21-1188 Section 4 Rate Case Settlement, are assumed to be in effect throughout the projection period.

Q. Please describe Distribution's FY2024 and FY2025 storage rate derivation in PGC Exhibit No. 23, Schedule 1, Pages 13 and 14.

A. Distribution's Pennsylvania Division's storage rate derivation mirrors the calculation performed at the

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1 end of each fiscal year. The annual gas costs
2 inclusive of commodity and demand purchased gas costs,
3 upstream transportation costs and storage rental costs
4 are totaled. The cost of gas purchased for off-system
5 sales is excluded from the storage rate calculation.
6 The net cost is then divided by the annual gas
7 delivery volume at Distribution's Pennsylvania
8 Division Citygate.

9 Q. Please explain PGC Exhibit No. 23, Schedule 2.

10 A. PGC Exhibit No. 23, Schedule 2 is Pennsylvania's
11 Appalachian Production ("AP") and Local Production
12 ("LP") volume and cost summaries. AP is production
13 received directly by Supply and transported by Supply
14 to Distribution whereas LP is production received
15 directly by Distribution without the use of Supply's
16 facilities. Effective in this 1307(f) filing,
17 Distribution has one AP Production Rate. AP
18 Production Rate 1 is priced at the forecasted wellhead
19 rate plus a monthly adjustment. The monthly
20 adjustment is a composite rate that reflects that
21 approximately 35% of the AP is purchased pursuant to
22 spot contracts that are priced at 84% of the
23 Appalachian Index and 65% is purchased pursuant to
24 dedicated (Life-of-Reserves) contracts that are priced

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1 at 100% of the Appalachian Index. Distribution also
2 has one LP Production Rate. LP Production Rate 1 is
3 priced at the forecasted wellhead rate plus a monthly
4 adjustment. The monthly adjustment is a composite
5 rate that reflects that approximately 84% of the LP is
6 purchased pursuant to spot contracts that are priced
7 at 84% of the Appalachian Index and 16% is purchased
8 pursuant to dedicated (Life-of-Reserves) contracts
9 that are priced at 100% of the Appalachian Index.

10 Q. Please explain PGC Exhibit No. 23, Schedule 3.

11 A. PGC Exhibit No. 23, Schedule 3 summarizes
12 Distribution's contracted capacity and rates by
13 pipeline for the period December 2023 through October
14 2025.

15 Q. Please explain PGC Exhibit No. 24.

16 A. PGC Exhibit No. 24 is a summary of data and
17 calculations which support Distribution's Monthly
18 Metered Transportation ("MMT") and Daily Metered
19 Transportation ("DMT") service rates. Please refer to
20 Lisa Petko's testimony for information on design peak
21 day.

22 Q. Please provide a general description of Distribution's
23 existing MMT and DMT rates.

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1 A. MMT rates include a purchased gas cost component
2 designed to recover the costs of balancing the
3 difference between MMT customers' daily deliveries and
4 daily usage. Since MMT customers' meters are read
5 monthly, actual daily consumption data for MMT
6 customers is not available. Therefore, an estimate of
7 peak day transportation usage and deliveries is used
8 to calculate the costs of providing balancing service
9 to MMT customers.

10 Purchased gas costs are excluded from the DMT
11 unit transportation rate. To be a DMT customer, it is
12 necessary for daily metering and communications
13 equipment to be installed not only at the customer's
14 premises, where it receives service from Distribution,
15 but also at the point of delivery of the customer's
16 gas supplies into Distribution's system. Since DMT
17 customer deliveries and usage are monitored on a daily
18 basis, the purchased gas costs associated with
19 balancing for DMT services are recovered through the
20 over delivery and sales rates charged to the DMT
21 customer based upon the customer's actual daily usage
22 of the sales and over delivery services.

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1 Q. What are the purchased gas capacity costs that
2 Distribution expects to incur to provide
3 transportation services?

4 A. PGC Exhibit No. 24A provides a calculation of the
5 purchased gas capacity costs Distribution expects
6 transportation customers to cause it to incur. Tables
7 I through V of Appendix I of PGC Exhibit No. 24A
8 provide an estimate of purchased gas capacity costs
9 expected to be incurred to provide transportation
10 customers with service.

11 Q. How does Distribution recover these costs from
12 transportation customers?

13 A. As explained in PGC Exhibit No. 24, the purchased gas
14 costs associated with providing service to
15 transportation customers are recovered from MMT
16 transportation customers through the MMT charges.

17 Q. At page 7 of PGC Exhibit No. 24, it is explained that
18 the design peak day deficiency of DMT customers has
19 been excluded from the storage delivery calculation
20 because a DMT customer's access to peak day storage
21 deliverability is, in effect, interruptible.

22 Q. Please explain why such access to storage
23 deliverability is effectively interruptible.

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1 A. The DMT service tariff includes an Operational Flow
2 Order provision whereby Distribution may restrict the
3 daily metered customers' access to banked gas
4 supplies. The restriction of the DMT customers'
5 access to banked supplies allows Distribution to
6 restrict the DMT customers' use of storage
7 deliverability so that such storage deliverability can
8 be used for the benefit of sales customers.

9 Q. What is the proposed charge to recover purchased gas
10 costs associated with transportation service included
11 in the MMT rate schedule?

12 A. The transportation rates for MMT service include a
13 component for the recovery of purchased gas capacity
14 costs. The unit cost as shown in PGC Exhibit No. 24A,
15 is \$0.5792 per Mcf. The Company is increasing the MMT
16 rate from \$0.3700 to \$0.5800 per Mcf.

17 Q. Explain the DMT rate schedule.

18 A. The DMT rate schedule is available to transportation
19 customers that transport volumes to Distribution,
20 either directly or by displacement, on a firm or
21 interruptible basis. Customers under the DMT rate
22 schedule will not be charged the \$0.5800 per Mcf which
23 is charged to MMT customers. Excess deliveries for
24 DMT customers, however, are charged a greater amount

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1 than MMT customers, as explained in further detail
2 below. The DMT customer's deliveries and usage must
3 be metered on a daily basis. If, in any day, the DMT
4 customer uses more gas from Distribution than the sum
5 of: (1) any over delivery volumes at the beginning of
6 the day, (2) the volume of gas, after line losses,
7 delivered to Distribution for the customer's account
8 on that day, and (3) two percent of the total daily
9 usage, such use in excess of the sum of (1), (2) and
10 (3) above is deemed to be a sale of gas by
11 Distribution to the DMT customer under the applicable
12 sales rate schedule.

13 Q. Please explain the charges for over deliveries under
14 the DMT rate schedule.

15 A. The over delivery charges for DMT customers are based
16 on the maximum cumulative daily over delivery for DMT
17 customers. For a maximum cumulative over delivery
18 volume between 2% and 37% of the volume of DMT service
19 gas transported by Distribution to the customer in the
20 billing month, the charge for over deliveries is
21 \$0.6351 per Mcf. For over deliveries equal to or more
22 than 37% of the volume of DMT service gas transported
23 to the customer by Distribution during the billing

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1 month, the charge for such over deliveries shall be
2 \$0.7624 per Mcf.

3 Q. If a transportation service customer reverts back to
4 sales service and, as a result, Distribution does not
5 recover capacity costs from the transportation service
6 customer, would an under recovery of purchased gas
7 costs result?

8 A. No. Customers are free to switch back and forth
9 between sales and transportation service when
10 Distribution has sufficient gas supply and pipeline
11 transmission capacity to accommodate the return of
12 transportation customers to sales service. If a
13 present transportation customer decides to switch back
14 to sales service, the result would be simply that the
15 same customer would contribute to recovery of
16 purchased gas costs through payment of rates for sales
17 service instead of through payment of transportation
18 service rates.

19 Q. Why has the Company proposed no change in retention
20 rates for transportation service in this case?

21 A. The Company reviewed its current MMT and DMT service
22 rates to determine whether the current recovery of
23 purchased gas cost rates and the current .15% charged
24 transportation customers to compensate for line losses

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1 and company usage ("transportation retention rate")
2 continue to be appropriate. This review concluded
3 that current purchased gas cost rates included in
4 charges to MMT customers should increase to \$0.58 per
5 Mcf, and the imbalance service rates charged
6 transportation customers and the currently effective
7 line loss retention rates should not be changed. This
8 proposal for services provided to transportation
9 customers reasonably balances the purchased gas cost
10 recovery obligation of sales and transportation
11 customers.

12 Q. What issues did the Company consider when making its
13 proposal for MMT and DMT transportation service rates?

14 A. The Company considers the issues of the appropriate
15 purchase gas cost, balancing, and retention rates to
16 be charged transportation customers for line loss to
17 be matters of rate design.

18 PGC Exhibit No. 33, Schedule 1 provides a summary
19 of the criteria of a sound rate structure. The
20 Company believes that its existing and proposed
21 charges to transportation customers are consistent
22 with these criteria.

23 Q. Is there any evidence that the current and past rates
24 charged to MMT and DMT customers, including retainage

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1 rates, have been an impediment to transportation
2 service on the Company's system?

3 A. No, the evidence is clearly contrary to any suggestion
4 that the Company's MMT and DMT rates and the retainage
5 rates charged transportation customers have been an
6 impediment to transportation service. Transportation
7 service over the past 40 years has grown to 55% of
8 total system throughput. Nearly all industrial and
9 public authority customers have migrated from sales
10 service to transportation service.

11 It is clear from this evidence that the
12 transportation service and retainage rates have fairly
13 balanced the interests of transportation service
14 customers.

15 Q. Does the Company's proposal in this proceeding fairly
16 allocate costs incurred by the Company to provide
17 service to transportation service customers?

18 A. Yes, the proper allocation of purchased gas costs to
19 transportation customers has been an issue in the
20 Company's purchased gas cost proceedings since the
21 implementation of Order 636 which was issued by the
22 Federal Energy Regulatory Commission in 1993. See PGC
23 Exhibit No. 24, starting at line 11 of page 1 for the
24 list of 1307(f) cases where this issue was addressed.

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1 In order to support transportation services, the
2 Company incurs costs in the way of capacity costs,
3 principally on its affiliated pipeline, Supply. The
4 precise measurement of these costs is impossible since
5 a precise measurement would require daily measurement
6 on all transportation customers as well as all gas
7 receipt points into the Company's system, including
8 local gas production meters (see PGC Exhibit No. 24,
9 starting at line 16 of page 4). Therefore, the
10 calculation relies on estimates. Any attempt to
11 determine the exact cost of servicing transportation
12 customers would require resolving a number of
13 ancillary issues including, for example, previous
14 period reconciliation, that only add to the overall
15 complexity and cost of determining and administering
16 any mechanism designed to precisely quantify and
17 recover those costs.

18 It is useful to place the overall magnitude of
19 purchase gas cost recovery rates for sales and
20 transportation customers and actual sales and
21 transportation volumes into context. Table TLW-1
22 demonstrates that, from the perspective of overall gas
23 cost recovery, gas cost revenues associated with

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1 transportation service represent a small fraction of
2 overall gas costs.

Table TLW-1				
	Volumes		Gas Cost	
	Mcf	%	\$	%
Sales	21,817,752	44.5	125,432,133	95.4
MMT	8,983,462	18.3	5,210,408	4.0
SATC	2,012,390	4.1	888,470	0.7
DMT	16,190,046	33.0	0	0.0
Total	49,003,650	100	131,531,011	100.0

3 While one can argue about the allocation of gas
4 costs to transportation services, the overall impact
5 on natural gas energy bills charged by the Company to
6 customers is not likely to be significant (i.e.,
7 overall changes in gas cost allocation, even if
8 capable of being precisely measured, are likely to be
9 around 4.0% of overall gas cost).

10 Q. Why is the Company proposing to maintain existing
11 transportation over delivery rates?

12 A. Transportation over delivery rates present a unique
13 issue associated with transportation services.
14 Transportation over deliveries, the rates charged for
15 those over deliveries, and the costs incurred by the
16 Company due to those over deliveries cannot be
17 reconciled in a traditional cost-based rate
18 perspective because transportation over and under

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1 delivery rates are not designed solely to recover
2 specific identifiable costs incurred by transportation
3 customers. Instead, the over and under delivery rates
4 on the Company's system are designed for the
5 additional purpose of providing an incentive to
6 transportation customers and their suppliers to
7 deliver sufficient supplies to meet their customers'
8 daily requirements so that the reliability of gas
9 supply service of the overall distribution system is
10 maintained. As mentioned, starting at line 24 of page
11 11 of PGC Exhibit No. 24, imbalance rates were not
12 designed to provide transportation customers with
13 storage service. Instead, they are designed to
14 provide sufficient incentive for transportation
15 customers and their natural gas suppliers to remain in
16 balance. Existing over delivery rates have been
17 sufficient to provide such incentive. Because costs
18 of providing transportation service cannot be
19 quantified precisely and because they are designed
20 also to create incentives, reasonable judgment is
21 required to establish reasonable transportation rates
22 that are fair to all customers on the system including
23 sales and transportation customers. Distribution

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1 believes that its proposal for MMT and DMT rates
2 achieve this objective.

3 Q. Please describe PGC Exhibit No. 28.

4 A. Exhibit No. 28 is the Company's proposed tariff. The
5 normal rate changes are in Supplement No. 269
6 associated with changes in gas cost.

7 Q. Please explain PGC Exhibit No. 29.

8 A. PGC Exhibit No. 29 provides the calculation of the
9 weighted average demand cost of upstream capacity and
10 the demand transfer rate ("DTR") associated with the
11 SATS rate schedule.

12 The weighted average demand cost of upstream
13 capacity provides the rate charged to SATS suppliers
14 for capacity release that consolidates the upstream
15 transmission capacity costs into a single rate that is
16 priced at the same effective cost as if the Supplier
17 was allocated a pro rata share of every segment of
18 transmission capacity held by the Company.

19 Q. Please explain the DTR.

20 A. The DTR is utilized to recover from NGSS the costs of
21 capacity incurred by sales customers prior to the
22 conversion of the sales customer to transportation
23 service. Under the SATS rate schedule, NGSS receive a
24 transfer of gas in storage for all customers that

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1 convert to transportation service after the month of
2 April. The DTR is designed to remove any incentive for
3 the NGS to convert sales customers after the summer
4 period to avoid the assignment of upstream capacity
5 during the summer period when sales volumes are low.
6 Absent the DTR, NGSS could avoid capacity costs during
7 the summer period when sales volumes and associated
8 revenues are low and only incur such capacity costs by
9 converting customers after the summer period where
10 sales volumes and associated revenues are high. The
11 DTR eliminates any such incentive and protects the
12 remaining sales customers from paying costs that are
13 incurred for the benefit of transportation customers.

14 Q. Please explain PGC Exhibit No. 34.

15 A. PGC Exhibit No. 34 is the calculation of the Company's
16 Priority Standby ("PSB") Service rates and Standby
17 ("SB") Service rates.

18 Q. Does this conclude your testimony?

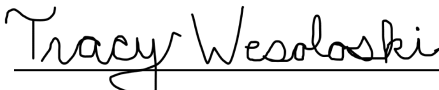
19 A. Yes, at this time.

Verification

I, Tracy L. Wesoloski, Assistant Manager, of the Rates & Regulatory Affairs Department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 6 Direct Testimony of Tracy L. Wesoloski
Exhibit Nos. 2 (partial), 3 (partial), 13, 13A, 17, 23, 24, 24A, 28, 29, 33, and 34.

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.



Tracy L. Wesoloski

This 31st day of January, 2024

TESTIMONY OF
LISA A. PETKO
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R- R-2024-3045177

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 Q. Please state your name and business address.

2 A. My name is Lisa A. Petko, and my business address is
3 6363 Main Street, Williamsville, New York 14221.

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

5 A. I am employed by National Fuel Gas Distribution
6 Corporation ("Distribution" or the "Company") as an
7 Assistant General Manager in the Gas Supply
8 Administration ("GSA") Department.

9 Q. What are your duties as Assistant General Manager?

10 A. I am responsible for managing GSA's back-office
11 functions including the Gas Accounting, Gas Planning
12 and Transportation Services groups. I also assist in
13 implementing Distribution's Gas Capacity policies.

14 Q. Please summarize your education and work experience.

15 A. I received a Bachelor of Business Administration
16 Degree in Accounting from Niagara University in 1988.
17 I was hired by National Fuel Gas Supply Corporation
18 ("NFGSC" or "Supply") in October 1990 as a Management
19 Trainee in the Gas Supply Department. I transferred to
20 Distribution's Gas Measurement Department in 1992, and
21 in 1994 I transferred to the Transportation & Exchange
22 group of NFGSC's Gas Supply Department. In 1996 I
23 transferred to Distribution's Contract Administration

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 Department. In 2000 I was promoted to the Manager of
2 Gas Accounting within GSA; in 2008 I became a Director.
3 In 2018 I was promoted to my current position.

4 Q. What is the subject of your testimony?

5 A. I am testifying in support of PGC Exhibit Nos. 4
6 (partial), 5, 7-B, 8 (partial), 12, 18, 19, 20, 26-B,
7 30, and 31.

8 Q. Please describe PGC Exhibit No. 4.

9 A. PGC Exhibit No. 4 is Distribution's response to the
10 Pennsylvania Public Utility Commission's ("PAPUC")
11 filing requirement at 52 Pa. Code § 53.64(c)(1), which
12 requires details of Distribution's contracts for gas
13 supplies and upstream pipeline transportation and
14 storage capacity, their rate designs and recent and
15 pending negotiations.

16 I am sponsoring page 2 line 19 through page
17 5 line 17, page 13 and PGC Exhibit No. 4-A. These
18 sections describe Distribution's pipeline, storage and
19 winter gas supply capacity, no cost gas exchange
20 agreements, other utility purchases, Small Aggregation
21 Transportation Customer ("SATC") capacity, non-firm
22 local production gas purchases, and tariff-based gas
23 purchases.

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 Distribution reviews its available options
2 for upstream capacity before determining whether to
3 renew or terminate any existing pipeline, storage,
4 winter gas supply or firm local production contracts.
5 PGC Exhibit No. 4 provides details of capacity
6 revisions made during the historic period, the 12
7 months ended November 30, 2023.

8 PGC Exhibit No. 4-A presents Distribution's
9 current contracts, volumes, notice period and contract
10 terms.

11 For the winter 2023-2024, approximately 86%
12 of Distribution's contracted upstream firm
13 transportation capacity now has primary receipt in the
14 Northeast (short-haul capacity) and 14% is from the
15 Southwest (long-haul capacity). See Exhibit LAP-1.

16 Q. Please explain PGC Exhibit No. 5.

17 A. PGC Exhibit No. 5 is Distribution's response to the
18 PAPUC's filing requirement at 52 Pa. Code § 53.64(c)
19 (3). The filing requirement calls for information
20 pertaining to sources of gas supply, transportation,
21 or storage, which were offered to, or considered by,
22 Distribution during the time periods relevant to this
23 1307(f) filing but were not accepted.

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 Q. Please explain PGC Exhibit No. 7-B.

2 A. PGC Exhibit No. 7-B is part of Distribution's response
3 to the PAPUC filing requirement at 52 Pa. Code §53.64
4 (c)(5) which requires a listing and updating of any
5 gas supply and demand projections provided to the
6 PAPUC. Pages 2, 3, 4 and 5 of PGC Exhibit No. 7-B are
7 copies of Distribution's most recently filed Annual
8 Resource Planning Reports: Form-IRP-Gas-2A: Table 2,
9 Form-IRP-Gas-2B, Form-IRP-Gas-2C, and Form IRP-Gas-2A,
10 which break out Distribution's gas supply, pipeline
11 and storage capacity on both an annual and a peak-day
12 basis in accordance with PAPUC Docket No. L-920066:
13 Integrated Resource Planning for Gas Utilities
14 pursuant to 52 Pa. Code §59.81-84.

15 Q. Please explain PGC Exhibit No. 8.

16 A. I am sponsoring page 2 line 1 through page 10 line 13,
17 and page 13 lines 18 through 21 and page 14 lines 1
18 through 6, as well as PGC Exhibit Nos. 8-A, 8-B, 8-C
19 and 8-D with regard to capacity reserved for
20 Distribution's customers, capacity retained for
21 temperature variability and peaking, purchase of non-
22 firm local production and Appalachian supplies and
23 tariff-based gas purchases. In general, PGC Exhibit

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 No. 8 describes Distribution's overall gas supply and
2 capacity procurement strategy and provides details of
3 changes that Distribution anticipates that it will
4 make during the link period, the 8 months from
5 December 1, 2023, through July 31, 2024, and during
6 the application period, the 12 months beginning August
7 1, 2024, and ending July 31, 2025. As explained in PGC
8 Exhibit No. 8, there are many factors to be considered
9 in developing a reliable gas supply for firm customers
10 on a least cost basis.

11 Distribution relies on its firm
12 transportation capacity on upstream interstate
13 pipelines to deliver the majority of its gas supplies
14 to Supply. Supply, through its interstate pipeline
15 system, re-delivers Distribution's gas to its isolated
16 distribution systems throughout Northwestern
17 Pennsylvania and Western New York. Supply also owns
18 extensive storage facilities that it operates in
19 concert with its transmission facilities to receive
20 gas (injections) from Distribution during periods of
21 low customer demand. Supply subsequently re-delivers
22 this gas (withdrawals) to Distribution during the
23 winter when market requirements exceed flowing gas

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 supplies available from its upstream pipeline
2 capacity. Such storage injections and withdrawals for
3 the 12-month period of October 1, 2022, through
4 September 30, 2023, are depicted in PGC Exhibit No. 8-
5 C. PGC Exhibit No. 8-B shows how Distribution's
6 combined transportation, storage and winter gas call
7 capacities can meet the requirements of a 15%
8 forecasted colder-than-normal winter.

9 The interdependent relationship between
10 Supply and Distribution is evidenced in the Supply
11 System map shown in PGC Exhibit No. No. 8-A. As
12 explained in PGC Exhibit No. 8, Distribution receives
13 gas from Supply at approximately 286 delivery points
14 in Pennsylvania and 135 in New York at geographically
15 dispersed areas where Distribution has facilities and
16 customers. The pink lines are the major transmission
17 lines of the pipeline companies that deliver gas in
18 Northwestern Pennsylvania and Western New York. The
19 blue lines represent major transmission lines and
20 storage facilities of Supply that interconnect
21 Distribution's facilities and customers with the
22 facilities of the upstream interstate pipelines.

23 Q. Please define "critical capacity."

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 A. All of Distribution's pipeline and storage capacity is
2 critical capacity. This mix of capacity meets
3 Distribution's unique market reliability requirements
4 at the least cost to the customer. The capacity plays
5 a critical role in directly serving customer
6 requirements including filling Distribution's
7 contracted storage capacity with Supply. Distribution's
8 no-notice Enhanced Firm Transportation ("EFT")
9 capacity and associated Enhanced Storage Service
10 ("ESS") capacity that it maintains with Supply is used
11 to serve the requirements of its customers located
12 throughout its geographically extensive, yet
13 unconnected, system. In addition, Distribution holds
14 Firm Transportation ("FT") capacity on Supply.
15 Distribution's system relies on its upstream capacity
16 for the procurement of adequate and reliable gas
17 supply. Distribution's upstream capacity includes its
18 firm transportation capacity on Columbia Gas
19 Transmission, LLC ("Columbia"), Tennessee Gas Pipeline
20 Company, L.L.C. ("TGP"), Texas Eastern Transmission,
21 LP ("TETCO") and Firm Storage Service ("FSS")
22 capacities on Supply and Columbia. Discussion
23 beginning at page 2 line 11 through page 5 line 5 of

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 PGC Exhibit No. 8 serves to more fully explain the
2 "critical" role that Distribution's upstream pipeline
3 and storage capacities serve in meeting its firm
4 service requirements.

5 Q. Please describe the methodology and calculations
6 presented on PGC Exhibit No. 8-D.

7 A. The purpose of PGC Exhibit No. 8-D is to present the
8 calculations used to determine the quantity of
9 capacity that Distribution will retain to meet the
10 temperature swing and peaking requirements of its
11 sales and SATC service customers and to determine the
12 mix of Supply ESS storage and upstream transportation
13 capacity that Distribution will release to its Small
14 Aggregation Transportation Supplier ("SATS") service
15 suppliers in order to serve its SATC customers'
16 requirements on a Design Day and during a 15% colder-
17 than-normal winter.

18 Q. Has Distribution executed, or is it considering
19 executing, any capacity adjustments in the future?

20 A. Distribution routinely explores opportunities to
21 modify its upstream pipeline assets to improve
22 reliability or reduce costs.

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 In June 2023, Distribution exercised an
2 option to shorten up critical TGP capacity to reduce
3 costs without compromising reliability. Further
4 details are provided in PGC Exhibit 8 beginning on
5 page 9, lines 11-20.

6 Q. Please describe Distribution's contingency capacity
7 requirements.

8 A. Distribution requires contingency capacity to serve
9 its sales and transportation customers should there be
10 a capacity or supplier failure, force majeure instance
11 or should the system experience load requirements that
12 exceed current design peak day projections.

13 Q. Can contingency capacity be used to support services
14 to Monthly Metered Transportation ("MMT") customers?

15 A. Yes. As described in PGC Exhibit No. 24, Distribution
16 allocates a pro-rata quantity of its total contingency
17 capacity to its MMT customers. The availability of
18 contingency capacity to support services to MMT
19 customers does not imply that natural gas suppliers
20 can avoid any part of their daily delivery quantity
21 ("DDQ") requirements. Pursuant to Distribution's
22 tariff, DDQ requirements for MMT customers must be
23 met.

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 Q. Please explain how the quantity of contingency
2 capacity is determined.

3 A. Contingency capacity is the difference between design
4 day requirements and the intermediate Supply EFT/FT
5 capacity NFGDC contracts for deliveries to NFGDC. Over
6 time, Distribution has adjusted its intermediate and
7 upstream capacity due to changes in the forecasted
8 market requirements, but not on a one-for-one basis.
9 Distribution considers a reasonable level of
10 contingency capacity as a safety factor when
11 evaluating capacity adjustments.

12 Q. Please describe Exhibit Nos. LAP-2, LAP-3, and LAP-4.

13 A. Exhibit LAP-2 is a graphical representation that
14 compares Distribution's actual city-gate throughput
15 when extrapolated to a 74 Heating Degree Day ("HDD"),
16 as represented by the green diamonds, to the combined
17 forecast total requirements plus the contingency
18 capacity, as shown by the stacked blue and red
19 columns, for each day of the three-day peaks. This
20 data includes the highest throughput over a three-day
21 period for the ten most recently completed winter
22 heating seasons including November 2013 through March
23 2023.

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 Exhibit LAP-3 presents the same comparison
2 as Exhibit LAP-2 but includes all days that on average
3 were 15 degrees Fahrenheit or colder for the time
4 period of November 2013 through December 31, 2023.
5 Please note that Distribution did not experience any
6 days 15 degrees Fahrenheit or colder for winter 2020-
7 2021. The forecast total requirements and contingency
8 capacity for the current winter and following two
9 years are also shown.

10 Exhibit LAP-4 provides a summary table of
11 the total forecast requirements and contingency
12 capacity for Distribution's design day beginning with
13 the winter of 2018.

14 Distribution will review its design day firm
15 capacity requirements again after analyzing its system
16 usage during this winter of 2024. Based upon that
17 analysis, Distribution will determine if further
18 adjustments to its capacity are required.

19 Q. Is Distribution considering obtaining additional
20 intermediate Supply capacity delivery to
21 Distribution's city-gate?

22 A. As discussed in Exhibit 8, page 8 line 20 through page
23 9 line 5, Distribution is considering contracting for

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 additional intermediate capacity for the winter of
2 2024-2025. Please refer to LAP-4, which is a summary
3 of 5 years of historical and 5 years of forecasted
4 contingency capacity. As presented in the contingency
5 capacity column, Distribution is seeing a reduction in
6 its overall contingency capacity volume. To ensure a
7 sufficient contingency volume for deployment during
8 unplanned events described above, Distribution
9 typically maintains a volume that is above 3% of total
10 forecasted requirements. Distribution is proposing to
11 contract for additional intermediate capacity of a
12 minimum of 5,000 dth/day with Supply for the winter of
13 2024-2025. This change is reflected in the bottom
14 portion of LAP-4.

15 Q. Please describe PGC Exhibit No.12.

16 A. PGC Exhibit No. 12 provides reference to select
17 supporting information from NFGSC's tariff that
18 identifies numerous operating characteristics of the
19 system. Also listed are the two industrial end users
20 that represented 5% or more of Distribution's
21 Pennsylvania Division throughput in any month during
22 the historic period.

23 Q. Please explain PGC Exhibit No. 18.

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 A. PGC Exhibit No. 18 is Distribution's response to 52
2 Pa. Code § 53.65(2). This exhibit identifies
3 Distribution's access to gas supplies via various
4 upstream pipelines. The transportation and storage
5 available to Distribution from these upstream
6 pipelines is provided in PGC Exhibit Nos. 4 and 7-B.

7 Q. Please explain PGC Exhibit No. 19.

8 A. PGC Exhibit No. 19 is Distribution's response to 52
9 Pa. Code § 53.65(3) and (4). This exhibit explains in
10 what instances Distribution obtains purchased gas from
11 affiliated sources. Distribution refers to PGC Exhibit
12 No. 8 for an explanation of its efforts to obtain gas
13 supplies, transportation, or storage from unaffiliated
14 sources as well as transportation and storage capacity
15 from affiliated sources.

16 Q. Please explain PGC Exhibit No. 20.

17 A. PGC Exhibit No. 20 is Distribution's response to 52
18 Pa. Code § 53.65(5). Distribution explains that
19 neither it nor any of its relevant affiliated
20 interests withheld any transportation or storage
21 capacity from the market. The availability and
22 purchases of local production by Distribution are
23 discussed in detail in PGC Exhibit No. 8.

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 Q. Please explain PGC Exhibit 26-B.

2 A. PGC Exhibit 26-B sets forth the winter of 2025 design
3 day city-gate requirements that are forecast to be
4 required by Distribution and by both aggregated and
5 non-aggregated transportation customers.

6 Q. Please explain PGC Exhibit No. 30.

7 A. PGC Exhibit No. 30 is a schedule that shows
8 Distribution's Pennsylvania Division's firm
9 requirements for a design day for the winter of 2024-
10 2025 and the capacity that will serve those
11 requirements. This exhibit provides an update to the
12 transportation and storage delivery capacity
13 information presented in last year's Annual Resource
14 Planning Report as presented in PGC Exhibit No. 7-B.
15 Distribution expects its design day capacity for the
16 winter of 2024-2025 to be 350,876 Dth/day.

17 Q. Please explain PGC Exhibit No. 31.

18 A. PGC Exhibit No. 31 is Distribution's response to the
19 requirements of 52 Pa. Code § 1317(c) and (d) to
20 provide its proposed reliability plan and its supply
21 plan. As explained in PGC Exhibit No. 31, relevant
22 information for these plans is contained in PGC
23 Exhibit Nos. 4, 4-A, 8, 15, 24, 26-A, 26-B and 30.

DIRECT TESTIMONY OF LISA A. PETKO
R-2024-3045177

1 Q. Did Distribution receive any pipeline penalty credits
2 or rate case settlement credits on the monthly
3 pipeline invoices during the 12 months ending November
4 30, 2023?

5 A. Yes, see Exhibit LAP-5 for a list of the credits
6 received in 2023.

7 Q. Does this conclude your testimony?

8 A. Yes, it does at this time.

Verification

I, Lisa A. Petko, Assistant General Manager, of the Gas Supply Administration Department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 8, Exhibit LAP-1, Exhibit LAP-2, Exhibit LAP-3, Exhibit LAP-4, Exhibit LAP-5, Exhibit Nos. 4 (partial), 5, 7-B, 8 (partial), 12, 18, 19, 20, 26-B, 30, and 31

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

Lisa A Petko

Lisa A. Petko

This 31st day of January, 2024

REBUTTAL TESTIMONY OF
LISA A. PETKO
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024-3045177

REBUTTAL TESTIMONY OF Lisa A Petko
R-2024-3045177

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

2 A. My name is Lisa A. Petko, and my business address is 6363 Main
3 Street, Williamsville, New York 14221.

4 **Q. Are you the same Lisa A. Petko that submitted Direct Testimony**
5 **in the instant docket?**

6 A. Yes. I submitted Distribution PGC Statement No. 7 along with
7 Exhibit Nos. LAP-1, Exhibit LAP-2, Exhibit LAP-3, Exhibit LAP-4, and
8 Exhibit LAP-5.

9 **Q. What is the subject of your rebuttal testimony?**

10 A. I am rebutting the direct testimony of Jerome D. Mierzwa on behalf of
11 the Pennsylvania Office of the Consumer Advocate (“PA OCA”)
12 regarding his recommendation that the Company not be permitted to
13 increase its interstate pipeline (NFG Supply) capacity entitlements
14 for winter 2024-2025.

15 **Q. Please summarize Mr. Mierzwa’s Direct Testimony regarding his**
16 **objection to the Company acquiring additional NFG Supply**
17 **Capacity.**

18 A. Mr. Mierzwa recommends that the Company not be permitted to
19 increase its NFG Supply capacity for the winter 2024-2025 pending a
20 review of its design day forecasting model. (OCA St. No. 1, p. 12)

21 **Q. Do you agree with Mr. Mierzwa’s statement “[t]his contingency**
22 **capacity has historically been maintained to ensure reliability in**

1 **the event that the Company's system experiences load**
2 **requirements that exceed projected design day requirements.”?**

3 A. The Company partially agrees with this statement. However, the
4 Company also requires contingency capacity to serve its sales and
5 transportation customers should there be a capacity or supplier
6 failure, or a force majeure event.

7 Q. **Does the Company agree with Mr. Mierzwa's statement that**
8 **usage per HDD of weather-sensitive customers tends to**
9 **increase as HDDs increase?**

10 A. The Company agrees with Mr. Mierzwa's observation that usage per
11 HDD of weather-sensitive customers tends to increase as HDDs
12 increase, but it is difficult to precisely predict customers' behaviors
13 during extreme cold events. The Company must be prepared with
14 sufficient firm capacity to provide firm service to customers even
15 during those rare and unusual circumstances rather than taking a
16 wait and see approach.

17 Q. **Why does Mr. Mierzwa not want the Company to acquire this**
18 **capacity?**

19 A. Mr. Mierzwa appears to be concerned with the design day forecast
20 that results in the need for acquiring additional capacity and incurring
21 the associated demand cost.

REBUTTAL TESTIMONY OF Lisa A Petko
R-2024-3045177

1 **Q. Does the Company agree with the Mr. Mierzwa's**
2 **recommendation that the Company not acquire 5,000 Dth/d of**
3 **NFG Supply capacity for the winter 2024-2025?**

4 **A.** No. Based on the forecast it is appropriate for the Company to seek
5 additional NFG Supply capacity. To maintain capacity contract
6 flexibility, the Company proposes to limit the contract term for this
7 incremental capacity to no more than two years rather than a long
8 term commitment.

9 **Q. Do you have any additional comments to add?**

10 **A.** Yes. I note that further discussion regarding the design day forecast
11 is included in Greg Hartz's rebuttal testimony in PGC Statement No.
12 4R.

13 **Q. Does this conclude your rebuttal testimony?**

14 **A.** Yes, at this time.

Verification

I, Lisa A. Petko, Assistant General Manager, of the gas Supply Administration Department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 07 Rebuttal Testimony of Lisa A. Petko.

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

Lisa A Petko

Lisa A. Petko

This 22nd day of March, 2024

TESTIMONY OF
CATHLEEN M. CHERVEN-OCZYTKO
ON BEHALF OF
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
(PURCHASED GAS COSTS -- 66 PA.C.S. SECTION 1307(f)),
DOCKET NO. R-2024- 3045177

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
DOCKET NUMBER R-2024-3045177

1 Q. Please state your name and business address.

2 A. My name is Cathleen M. Cherven-Oczytko, and my
3 business address is 6363 Main Street, Williamsville,
4 New York 14221.

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

6 A. I am employed by National Fuel Gas Distribution
7 Corporation ("Distribution" or the "Company") as an
8 Assistant Manager for Market Planning in the Rates
9 and Regulatory Affairs Department.

10 Q. Please state briefly your educational and
11 professional experience.

12 A. In 1991, I received an Associate Degree in Computer
13 Science from Bryant & Stratton College. In 2009, I
14 received a BS in Computer Science from SUNY Buffalo
15 State University and, in 2022, I received an MBA
16 from the State University of New York at Buffalo.
17 For 15 years prior to working at the Company, I
18 worked for Sigma Systems, Inc. as a Senior Software
19 Developer for a custom CAMA (Computer Assisted Mass
20 Appraisal) system. I worked for the Company within
21 the Information Services department as a Programmer

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
DOCKET NUMBER R-2024-3045177

1 Analyst II, Systems Analyst, Senior Systems Analyst
2 and Business Systems Analyst from 2008 to 2022, and
3 I have worked as an Assistant Manager in the Rates &
4 Regulatory Affairs department since 2022.

5 Q. Have you previously testified before the
6 Pennsylvania Public Utility Commission
7 ("Commission")?

8 A. No. I have not previously testified before the
9 Commission.

10 Q. Have you previously testified before any other
11 regulatory commissions?

12 A. Yes. I have presented testimony before the New York
13 State Public Service Commission at Docket No. 23-G-
14 0627.

15 Q. What is the subject of your testimony?

16 A. I am testifying regarding PGC Exhibit Nos. 10, 11,
17 14, 16, 22, and 25.

18 Q. Were these exhibits prepared by you or prepared
19 under your supervision and direction?

20 A. Yes, they were.

21 Q. Is the content of these exhibits true and correct to

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
DOCKET NUMBER R-2024-3045177

1 the best of your knowledge, information, and belief?

2 A. Yes, it is.

3 Q. Please explain PGC Exhibit No. 10.

4 A. PGC Exhibit No. 10 explains that Distribution
5 maintains transportation agreements with its Daily
6 Metered Transportation customers and Natural Gas
7 Suppliers that provide Monthly Metered
8 Transportation service to customers.

9 Q. Please explain PGC Exhibit No. 11.

10 A. PGC Exhibit No. 11 provides monthly transportation
11 volumes by service classification (within the Daily
12 Metered Transportation and Monthly Metered
13 Transportation categories), customer counts for the
14 month of November 2023, and a summary of current
15 rates for transportation service. Daily Metered
16 Transportation volumes, and customer counts by
17 service class for Commercial, Industrial, and Public
18 Authority, are provided on page 2. Page 3 provides
19 Monthly Metered Transportation volumes, and customer
20 counts by service class for Residential and
21 Commercial. Page 4 provides Monthly Metered

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
DOCKET NUMBER R-2024-3045177

1 Transportation volumes, and customer counts by
2 service class for Industrial and Public Authority.
3 Pages 5 and 6 provide a summary of current
4 transportation rates, extracted from Distribution's
5 tariff.

6 Q. When did the portions of rates set forth in PGC
7 Exhibit No. 11, that provide for recovery of
8 purchased gas costs, become effective?

9 A. The portion of rates that provide for recovery of
10 purchased gas costs, as provided in PGC Exhibit No.
11 11, became effective on November 1, 2023, in
12 compliance with the Commission's Order issued on
13 June 15, 2023. This Order was from Distribution's
14 most recent annual gas cost proceeding, under
15 Section 1307(f) of the Public Utility Code, at
16 Docket No. R-2023-3037428. Under the procedure for
17 quarterly updates of purchased gas costs,
18 transportation rates may be adjusted quarterly
19 (i.e., November, February, May, and August). The
20 most recent filing was submitted on October 31,
21 2023, at Docket No. R-2023-3037428, with an

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
DOCKET NUMBER R-2024-3045177

1 effective date of November 1, 2023.

2 Q. Briefly describe Distribution's system-wide choice
3 plan.

4 A. Under the Natural Gas Choice and Competition Act
5 ("Act"), each natural gas utility in the
6 Commonwealth of Pennsylvania was required to submit
7 a restructuring plan to the Commission by November
8 1, 1999. Distribution's system-wide choice plan
9 under the Act was filed on October 1, 1999, at
10 docket R-00994785. Even before then, Distribution
11 offered choice to almost all customers, under a
12 prior plan that became effective on March 4, 1999.
13 Since then, Distribution's customers (except for one
14 group described below), have been allowed to choose
15 their own natural gas supplier for natural gas
16 service. That gas supply is transported through
17 natural gas delivery service that is provided by the
18 Company. Only customers who elect to participate in
19 the Low Income Residential Assistance ("LIRA")
20 program are not eligible to select a supplier other
21 than Distribution. Effective July 15, 2010,

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
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1 Distribution instituted a Purchase of Receivables
2 ("POR") program for qualified natural gas suppliers
3 on the Company's system.

4 The September 30, 2023 report filed with the
5 Commission regarding the number and percentage of
6 customers using alternative suppliers (i.e., NGDC
7 Customer Switching Statistics) explains that 8.7% of
8 residential customers, 28.6% of commercial
9 customers, and 70.7% of industrial customers chose
10 an alternative supplier. The percentage of load from
11 alternative suppliers is 9.8% for the residential
12 class, 79.3% for the commercial class, and 99.5% for
13 the industrial class. In total, for the month of
14 September 2023, 79.1% of the load is supplied from
15 alternative suppliers.

16 Q. Please explain PGC Exhibit No. 14.

17 A. PGC Exhibit No. 14 is a schedule showing, for the
18 most recent five years (i.e., November 2018 -
19 October 2019 through November 2022 through October
20 2023), consecutive three-day peak throughput data
21 (retail sales and end-user transportation service),

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
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1 by customer class (residential, commercial,
2 industrial, and public authority) for Distribution's
3 Pennsylvania Division. It also shows the high, low,
4 and average temperature for each consecutive three
5 days. December 23, 2022 - December 25, 2022 is the
6 most recent consecutive three-day peak. December 23,
7 2022 is the most recent peak day within that three-
8 day period specified in PGC Exhibit No. 14.

9 Q. Please explain PGC Exhibit No. 16.

10 A. PGC Exhibit No. 16 reflects Distribution's gas
11 requirements to provide reliable and uninterrupted
12 service to its priority one customers (residential
13 and firm critical commercial and public authority
14 essential human needs customers) during peak
15 periods. These requirements are calculated on both
16 historic and projected bases.

17 Q. Please explain PGC Exhibit No. 22.

18 A. PGC Exhibit No. 22 is composed of four pages. Page 2
19 provides the historic levels of retail sales volumes
20 in Mcf for Distribution's Pennsylvania Division for
21 the twelve months ended November 30, 2023. Page 3 of

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
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1 PGC Exhibit No. 22 provides the projected levels of
2 retail sales volumes in Mcf for Distribution's
3 Pennsylvania Division for the eight months ending
4 July 31, 2024. Page 4 provides the projected levels
5 of retail sales volumes in Mcf for the Company's
6 Pennsylvania Division for the twelve months ending
7 July 31, 2025. The projected retail sales volume of
8 21,817,752 Mcf, provided on page 4 of PGC Exhibit
9 No. 22, is the projected sales volume that is used
10 as Factor "S" in the computation of purchased gas
11 costs in PGC Exhibit 21.

12 Q. Please explain the methodology employed to project
13 the levels of sales volumes contained in PGC Exhibit
14 No. 22.

15 A. In Distribution's most recent base rate proceeding,
16 docket at R-2022-3035730, the Commission issued an
17 Order on June 15, 2023, which approved a settlement.
18 Rates became effective on August 1, 2023. The
19 methodology employed to project the level of sales
20 volumes for PGC Exhibit No. 22 is the same
21 methodology that was used in Distribution's last

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
DOCKET NUMBER R-2024-3045177

1 base rate proceeding.

2 Q. Please explain PGC Exhibit No. 25.

3 A. PGC Exhibit No. 25 provides Distribution's wellhead
4 price projection for December 2023 through December
5 2025. This wellhead price projection is based on
6 three projections of natural gas prices at Henry
7 Hub:

- 8 • The Energy Information Administration
- 9 ("EIA")
- 10 • New York Mercantile Exchange ("NYMEX")
- 11 • PIRA North American Gas ("PIRA"), owned by
- 12 S&P Global Platts

13 Page 2 calculates the wellhead price
14 projection. Page 3 provides the October 27, 2023 EIA
15 Henry Hub spot natural gas price from the Short-Term
16 Energy Outlook (for the months of November 2023
17 through December 2024). This information is included
18 in Column A on page 2 of PGC Exhibit No. 25.

19 Page 4 reflects the NYMEX trading activity for
20 the November 2023 close on October 27, 2023 (for the
21 months of December 2023 through December 2025). The

DIRECT TESTIMONY OF CATHLEEN M. CHERVEN-OCZYTKO
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1 projected settlement gas price is included in Column
2 B of page 2 of PGC Exhibit No. 25.

3 Page 5 of PGC Exhibit No. 25 shows PIRA's
4 forward curve gas price forecast for the months of
5 November 2023 through December 2025. This
6 information is included in Column C of page 2 of PGC
7 Exhibit No. 25.

8 The wellhead projection for December 2023
9 through December 2025 (as shown in Column D on page
10 2 of PGC Exhibit No. 25) is calculated by taking the
11 arithmetic average of the EIA spot natural gas price
12 (Column A), the NYMEX projected settlement gas price
13 (Column B), and the PIRA forward curve gas price
14 forecast (Column C).

15 Q. Does this conclude your direct testimony?

16 A. Yes, it does at this time.

Verification

I, *Cathleen M. Cherven-Oczytko*, Assistant Manager, of the Rates & Regulatory Affairs Department of National Fuel Gas Distribution Corporation state that the facts set forth in the foregoing Purchased Gas Cost Filing under Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 Docketed at R-2024-3045177 including

Distribution PGC Statement No. 8, Direct Testimony of Cathleen M. Cherven-Oczytko
Exhibit Nos. 10,11,14,16,22,25

are true and correct to the best of my knowledge, information and belief, and that I expect to be able to prove the same at a hearing held in this matter. This statement is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsifications to authorities.

Cathleen M. Cherven-Oczytko

Cathleen M. Cherven-Oczytko

This 31st day of January, 2024

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NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Summary of Cost of Gas by Gas Supplier and
Transmission of Gas by Local Producers
Twelve Months Ended November 2023

<u>Supplier</u>	<u>Projected Quantity Purchased</u> Mcf	<u>Commodity Cost</u> \$	<u>Demand Cost Natural Gas Supply</u> \$	<u>Demand Cost Distribution Charge</u> \$	<u>Total Projected Cost</u> \$
Upstream Purchases	19,462,736	57,634,848	403,606	0	58,038,454
Storage	(232,247)	731,735	11,262,471	0	11,994,207
Transportation		876,068	21,377,147	6,984,536	29,237,751
Transportation Credit			(3,146,333)	0	(3,146,333)
Local Production	214,351	384,396			384,396
Peoples Gas Company	5,583	61,620			61,620
Exchange Gas	(10,959)	(60,452)			(60,452)
Off-System Sales	0	0			0
Off-System Sales Refund		0			0
Subtotal	19,439,464	59,628,215	29,896,891	6,984,536	96,509,641
Credit - Line Hits		(4,476)			(4,476)
Total		<u>59,623,739</u>			<u>96,505,166</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Summary of Cost of Gas by Gas Supplier
Twelve Months Ended November 2023

<u>Supplier</u>	<u>Projected Quantity Purchased</u> Mcf	<u>Commodity Cost</u> \$	<u>Demand Cost</u> \$	<u>Total Projected Cost</u> \$
Upstream				
December 2022	2,567,006	16,653,331	87,601	16,740,931
January 2023	1,528,615	8,235,185	88,801	8,323,986
February	1,350,822	5,956,816	14,119	5,970,935
March	1,291,372	3,760,637	136,896	3,897,533
April	1,922,952	4,244,966	12,905	4,257,871
May	1,803,498	3,328,971	350	3,329,321
June	1,322,332	2,283,865	250	2,284,115
July	1,336,354	2,337,088	250	2,337,338
August	1,372,256	2,161,840	250	2,162,090
September	1,516,760	2,313,926	250	2,314,176
October	2,056,218	3,298,210	250	3,298,460
November	1,394,551	3,060,014	61,685	3,121,698
Total	19,462,736	57,634,848	403,606	58,038,454

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Summary of Cost of Gas by Gas Supplier
Twelve Months Ended November 2023

<u>Supplier</u>	Total Quantity <u>Purchased</u> Mcf	Commodity <u>Cost</u> \$	Total Projected <u>Cost</u> \$
Local Production			
December 2022	15,393	83,812	83,812
January 2023	19,034	59,007	59,007
February	14,452	76,104	76,104
March	18,151	(16,818)	(16,818)
April	15,001	19,667	19,667
May	19,916	28,539	28,539
June	19,907	23,712	23,712
July	17,247	20,896	20,896
August	17,870	18,400	18,400
September	20,285	18,480	18,480
October	19,617	23,464	23,464
November	<u>17,478</u>	<u>29,131</u>	<u>29,131</u>
Total	<u><u>214,351</u></u>	<u><u>384,396</u></u>	<u><u>384,396</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Summary of Transportation Credits
Twelve Months Ended November 2023

	2022					2023							
	December	January	February	March	April	May	June	July	August	September	October	November	Total
MMT Volume	919,038	1,217,233	1,154,342	1,064,465	1,054,146	668,538	480,482	379,475	343,550	364,887	415,889	629,065	8,691,110
Rate \$/Mcf	0.3600	0.3600	0.3600	0.3600	0.3600	0.3600	0.3600	0.3600	0.3700	0.3700	0.3700	0.3700	
Transportation Credit - \$	(330,854)	(438,204)	(415,563)	(383,208)	(379,492)	(240,674)	(172,974)	(136,611)	(127,114)	(135,008)	(153,879)	(232,754)	(3,146,333)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division
 Summary of Credit Due to Line Hits
 Twelve Months Ended November 2023

	2022						2023						
	December	January	February	March	April	May	June	July	August	September	October	November	Total
Line Hits (Credit) Amount - \$	107	368	50	292	1	45	365	479	892	16	1,225	638	4,476

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division
 Summary of Exchange Gas
 Twelve Months Ended November 2023

	2022 December	January	February	March	April	May	2023 June	July	August	September	October	November	Total
Exchange Gas - Mcf	6,277	8,980	(4,814)	14,401	5,514	3,447	4,707	1,499	532	3,338	3,312	(58,152)	(10,959)
Commodity - \$	62,264	78,372	(94,067)	62,845	(13,283)	(197,522)	(26,810)	(128,059)	(41,392)	549,955	94,559	(407,312)	(60,452)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division
 Summary of Off-System Sales
 Twelve Months Ended November 2023

	2022 December	January	February	March	April	May	2023 June	July	August	September	October	November	Total
Off-System Sales - Mcf	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-System Sales (Gas Cost) - \$	0	0	0	0	0	0	0	0	0	0	0	0	0

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Summary of Off-System Sales Refund
Twelve Months Ended November 2023

	2022	2023											
	December	January	February	March	April	May	June	July	August	September	October	November	Total
Off-System Sales Margin - \$	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-System Sales Refund (75%) - \$	0	0	0	0	0	0	0	0	0	0	0	0	0
Prior Period Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Off-System Sales Refund - \$	0	0	0	0	0	0	0	0	0	0	0	0	0

Note: Effective August 1, 2001 Sharing 75% / 25% before tax

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Details of Upstream Purchases
Twelve Months Ended November 2023

	2022			2023									
	December	January	February	March	April	May	June	July	August	September	October	November	Total
<u>Purchase Volume - Mcf</u>													
Spot	928,625	274,419	437,354	640,517	1,720,474	1,431,283	1,109,176	1,120,095	1,155,074	1,165,964	1,650,085	715,106	12,348,172
Contracted	1,683,288	1,291,073	946,162	679,930	228,571	398,216	230,567	234,673	235,745	374,463	437,172	701,236	7,441,096
Shrinkage	(44,907)	(36,877)	(32,694)	(29,075)	(26,093)	(26,001)	(17,411)	(18,414)	(18,563)	(23,667)	(31,039)	(21,791)	(326,532)
Total (Mcf)	2,567,006	1,528,615	1,350,822	1,291,372	1,922,952	1,803,498	1,322,332	1,336,354	1,372,256	1,516,760	2,056,218	1,394,551	19,462,736
<u>Demand Costs - \$</u>													
Spot	0	0	0	0	0	0	0	0	0	0	0	0	0
Contracted	87,601	88,801	14,119	136,896	12,905	350	250	250	250	250	250	61,685	403,606
Total Demand Costs - \$	87,601	88,801	14,119	136,896	12,905	350	250	250	250	250	250	61,685	403,606
<u>Commodity Costs - \$</u>													
Spot	4,797,777	836,254	1,052,909	1,445,339	3,276,592	2,512,607	1,734,804	1,775,417	1,594,422	1,625,107	2,482,312	1,448,939	24,582,478
Contracted	11,855,554	7,398,931	4,903,908	2,315,297	968,374	816,364	549,061	561,671	567,418	688,818	815,897	1,611,075	33,052,369
Total Commodity Costs - \$	16,653,331	8,235,185	5,956,816	3,760,637	4,244,966	3,328,971	2,283,865	2,337,088	2,161,840	2,313,926	3,298,210	3,060,014	57,634,848
Total Cost - \$	16,740,931	8,323,986	5,970,935	3,897,533	4,257,871	3,329,321	2,284,115	2,337,338	2,162,090	2,314,176	3,298,460	3,121,698	58,038,454

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Details of Storage

Twelve Months Ended November 2023

	2022	2023											
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>Total</u>
<u>Rental</u>													
Demand - \$	1,050,829	1,054,769	1,055,388	1,056,470	1,036,231	1,093,167	1,065,000	1,065,882	1,066,346	1,066,307	1,066,510	1,069,129	12,746,028
Commodity - \$	48,308	69,214	74,542	67,104	40,567	52,753	43,346	45,565	46,240	55,787	47,484	29,021	619,931
Total	<u>1,099,138</u>	<u>1,123,983</u>	<u>1,129,930</u>	<u>1,123,574</u>	<u>1,076,798</u>	<u>1,145,920</u>	<u>1,108,345</u>	<u>1,111,447</u>	<u>1,112,586</u>	<u>1,122,094</u>	<u>1,113,994</u>	<u>1,098,151</u>	<u>13,365,959</u>
<u>Gas Costs</u>													
Injection - Mcf	(99,720)	(37,416)	3,259	(2,930)	(594,508)	(1,113,925)	(940,683)	(1,005,582)	(975,930)	(1,169,912)	(1,052,094)	66,929	(6,922,512)
Withdrawal - Mcf	1,005,925	1,505,011	1,611,173	1,606,367	135,069	59,298	1,621	398	14,830	14,590	7,198	728,785	6,690,265
Net (Injection)/Withdrawal	<u>906,205</u>	<u>1,467,595</u>	<u>1,614,432</u>	<u>1,603,437</u>	<u>(459,439)</u>	<u>(1,054,627)</u>	<u>(939,062)</u>	<u>(1,005,184)</u>	<u>(961,100)</u>	<u>(1,155,322)</u>	<u>(1,044,896)</u>	<u>795,714</u>	<u>(232,247)</u>
Demand - \$	1,794,739	2,824,387	3,106,974	3,085,815	(950,809)	(2,182,551)	(1,943,389)	(2,111,288)	(2,018,694)	(2,426,638)	(2,776,393)	2,114,292	(1,483,557)
Commodity - \$	5,248,830	4,827,065	6,896,692	6,849,723	(4,452,732)	(3,827,874)	(3,408,419)	(3,545,591)	(3,490,907)	(4,248,201)	(3,089,549)	2,352,767	111,804
	<u>7,043,569</u>	<u>7,651,452</u>	<u>10,003,666</u>	<u>9,935,537</u>	<u>(5,403,541)</u>	<u>(6,010,425)</u>	<u>(5,351,808)</u>	<u>(5,656,879)</u>	<u>(5,509,602)</u>	<u>(6,674,839)</u>	<u>(5,865,942)</u>	<u>4,467,059</u>	<u>(1,371,753)</u>
<u>Total Storage Costs</u>													
Demand - \$	2,845,568	3,879,155	4,162,363	4,142,284	85,422	(1,089,383)	(878,389)	(1,045,407)	(952,348)	(1,360,331)	(1,709,883)	3,183,421	11,262,471
Commodity - \$	5,297,138	4,896,279	6,971,234	6,916,826	(4,412,164)	(3,775,121)	(3,365,074)	(3,500,026)	(3,444,668)	(4,192,414)	(3,042,064)	2,381,789	731,735
	<u>8,142,707</u>	<u>8,775,435</u>	<u>11,133,596</u>	<u>11,059,111</u>	<u>(4,326,742)</u>	<u>(4,864,505)</u>	<u>(4,243,463)</u>	<u>(4,545,433)</u>	<u>(4,397,016)</u>	<u>(5,552,745)</u>	<u>(4,751,948)</u>	<u>5,565,210</u>	<u>11,994,207</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Detail of Costs Related to Peoples Gas Company

Twelve Months Ended November 2023

	<u>2022</u>						<u>2023</u>						
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>Total</u>
Mcf	955	1,055	864	804	467	240	142	120	116	111	224	485	5,583
Amount - \$	13,017	13,225	10,675	9,954	4,276	2,136	1,350	1,074	1,007	976	1,410	2,520	61,620

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Transportation Charges
Twelve Months Ended November 2023

	2022						2023						
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>Total</u>
Demand - Distribution Charge - \$	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,096	6,984,536
Demand - Natural Gas Supply - \$	1,680,351	1,709,233	1,755,590	2,008,334	1,435,878	1,935,667	1,771,695	1,781,106	1,792,954	1,798,933	1,880,391	1,827,015	21,377,147
Total Demand - \$	2,262,391	2,291,273	2,337,630	2,590,374	2,017,918	2,517,707	2,353,735	2,363,146	2,374,994	2,380,973	2,462,431	2,409,111	28,361,683
Commodity - \$	125,828	130,444	109,774	84,822	69,031	41,319	36,928	38,390	44,646	55,158	68,431	71,296	876,068
Total Costs - \$	<u>2,388,219</u>	<u>2,421,717</u>	<u>2,447,404</u>	<u>2,675,196</u>	<u>2,086,949</u>	<u>2,559,026</u>	<u>2,390,663</u>	<u>2,401,536</u>	<u>2,419,640</u>	<u>2,436,131</u>	<u>2,530,862</u>	<u>2,480,407</u>	<u>29,237,751</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Temperature Swing / Peaking Capacity Costs

Twelve Months Ended November 2023

	2022						2023						
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>Total</u>
NFGSC EFT Capacity (Dth)	58,359	58,359	58,359	58,359	58,359	58,359	58,359	58,359	58,359	58,359	58,359	58,359	
Rate (\$/Dth)	5.1611	5.1611	5.1611	5.1611	5.1611	5.1611	5.1611	5.1611	5.1611	5.1611	5.1611	5.1512	
Amount (\$)	301,197	301,197	301,197	301,197	301,197	301,197	301,197	301,197	301,197	301,197	301,197	300,619	3,613,786
NFGSC ESS Delivery (Dth)	47,693	47,693	47,693	47,693	47,693	47,693	47,693	47,693	47,693	47,693	47,693	47,693	
Rate (\$/Dth)	2.7576	2.7576	2.7576	2.7576	2.7576	2.7576	2.7576	2.7576	2.7576	2.7576	2.7576	2.7643	
Amount (\$)	131,518	131,518	131,518	131,518	131,518	131,518	131,518	131,518	131,518	131,518	131,518	131,838	1,578,536
NFGSC ESS Capacity (Dth)	2,226,214	2,226,214	2,226,214	2,226,214	2,226,214	2,226,214	2,226,214	2,226,214	2,226,214	2,226,214	2,226,214	2,226,214	
Rate (\$/Dth)	0.0501	0.0501	0.0501	0.0501	0.0501	0.0501	0.0501	0.0501	0.0501	0.0501	0.0501	0.0502	
Amount (\$)	111,533	111,533	111,533	111,533	111,533	111,533	111,533	111,533	111,533	111,533	111,533	111,756	1,338,619
NFGSC FSS Capacity (Dth)	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	
Rate (\$/Dth)	2.6469	2.6469	2.6469	2.6469	2.6469	2.6469	2.6469	2.6469	2.6469	2.6469	2.6469	2.6536	
Amount (\$)	28,232	28,232	28,232	28,232	28,232	28,232	28,232	28,232	28,232	28,232	28,232	28,303	338,855
NFGSC FSS Capacity (Dth)	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	
Rate (\$/Dth)	0.0478	0.0478	0.0478	0.0478	0.0478	0.0478	0.0478	0.0478	0.0478	0.0478	0.0478	0.0479	
Amount (\$)	9,560	9,560	9,560	9,560	9,560	9,560	9,560	9,560	9,560	9,560	9,560	9,580	114,740
Grand Total Cost - Distribution Charge (\$)	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,040	582,096	6,984,536

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Summary of Cost of Gas by Gas Supplier and
Transmission of Gas by Local Producers
Eight Months Ended July 2024

<u>Supplier</u>	<u>Projected Quantity Purchased</u> (Mcf)	<u>Commodity Cost</u> (\$)	<u>Demand Cost Natural Gas Supply</u> (\$)	<u>Demand Cost Distribution Charge</u> (\$)	<u>Total Projected Cost</u> (\$)
Upstream Purchases	17,712,286	46,273,208	21,597,707	6,343,612	74,214,527
Storage		6,236,924	19,175,942	0	25,412,866
Transportation Credit			(2,350,465)	0	(2,350,465)
Capacity Release			(2,622,958)	0	(2,622,958)
Local Production	67,424	157,409			157,409
Peoples Gas Company	4,647	55,706			55,706
Subtotal	17,784,357	52,723,247	35,800,226	6,343,612	94,867,085
Credit - Line Hits		(1,705)			(1,705)
Total		<u>52,721,542</u>			<u>94,865,380</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Summary of Cost of Gas by Gas Supplier
Eight Months Ended July 2024

<u>Supplier</u>	<u>Projected Quantity Purchased</u> (Mcf)	<u>Commodity Cost</u> (\$)	<u>Demand Cost Natural Gas Supply</u> (\$)	<u>Demand Cost Distribution Charge</u> (\$)	<u>Total Projected Cost</u> (\$)
Upstream					
December 2023	3,059,731	7,081,010	2,083,525	538,517	9,703,052
January 2024	4,195,068	8,140,983	2,077,418	538,517	10,756,918
February	3,609,986	7,444,763	3,041,245	877,763	11,363,771
March	3,118,513	4,155,849	3,028,233	877,763	8,061,845
April	1,814,851	5,768,632	2,846,390	877,763	9,492,785
May	1,125,952	5,933,786	2,834,200	877,763	9,645,749
June	416,374	3,792,713	2,846,390	877,763	7,516,866
July	371,813	3,955,470	2,840,307	877,763	7,673,540
Total	17,712,286	46,273,208	21,597,707	6,343,612	74,214,527

See Exhibit 23, Schedule 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Summary of Cost of Gas by Gas Supplier
Eight Months Ended July 2024

<u>Supplier</u>	Projected Quantity <u>Purchased</u> (Mcf)	Commodity <u>Cost</u> (\$)	Total Projected <u>Cost</u> (\$)
Local Production			
December 2023	8,566	22,129	22,129
January 2024	8,566	23,631	23,631
February	8,014	20,921	20,921
March	8,566	19,920	19,920
April	8,290	17,061	17,061
May	8,566	17,440	17,440
June	8,290	17,184	17,184
July	8,566	19,123	19,123
Total	67,424	157,409	157,409

See Exhibit 23, Schedule 2

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Summary of Transportation Credits
Eight Months Ended July 2024

	2023	2024						
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>
MMT Volume	1,136,016	1,263,188	1,121,640	1,002,498	662,735	436,133	370,627	359,771
Rate \$ / Mcf	0.3700	0.3700	0.3700	0.3700	0.3700	0.3700	0.3700	0.3700
Transportation Credit - \$	(420,326)	(467,380)	(415,007)	(370,924)	(245,212)	(161,369)	(137,132)	(133,115)
								(2,350,465)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Summary of Credit Due to Line Hits
Eight Months Ended July 2024

	2023	2024							
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Total</u>
Line Hits (Credit) Amount - \$	107	368	50	292	1	45	365	479	1,705

[illegible]

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Summary of Off-System Sales Refund
Eight Months Ended July 2024

	2023 December	January	February	March	2024 April	May	June	July	Total
Off-System Sales Margin - \$	0	0	0	0	0	0	0	0	0
Off-System Sales Refund (75%) - \$	0	0	0	0	0	0	0	0	0
Prior Period Adjustment	0	0	0	0	0	0	0	0	0
Net Off-System Sales Refund - \$	0	0	0	0	0	0	0	0	0

Note: Effective August 1, 2001 sharing 75% / 25% before tax

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Details of Upstream Purchases (Including Transportation) ¹
Eight Months Ended July 2024

	2023 <u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	2024 <u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Total</u>
Purchase Volume - Dth	1,601,161	1,713,987	1,600,892	1,079,776	2,066,466	2,118,571	1,652,965	1,647,507	13,481,325
City Gate Volume - DTH	676,408	737,899	690,293	307,458	228,368	302,465	0	0	2,942,891
Storage Volume - Dth	938,208	1,957,130	1,502,910	1,890,323	(387,426)	(1,237,660)	(1,215,356)	(1,256,732)	2,191,397
Total Volume - Dth	<u>3,215,777</u>	<u>4,409,016</u>	<u>3,794,095</u>	<u>3,277,557</u>	<u>1,907,408</u>	<u>1,183,376</u>	<u>437,609</u>	<u>390,775</u>	<u>18,615,613</u>
Conversion Factor	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	
Total Volume - Mcf	3,059,731	4,195,068	3,609,986	3,118,513	1,814,851	1,125,952	416,374	371,813	17,712,286
Net Purchases - Mcf	<u>3,059,731</u>	<u>4,195,068</u>	<u>3,609,986</u>	<u>3,118,513</u>	<u>1,814,851</u>	<u>1,125,952</u>	<u>416,374</u>	<u>371,813</u>	<u>17,712,286</u>
Demand - Natural Gas Supply - \$	2,083,525	2,077,418	3,041,245	3,028,233	2,846,390	2,834,200	2,846,390	2,840,307	21,597,707
Demand - Distribution Charge - \$	538,517	538,517	877,763	877,763	877,763	877,763	877,763	877,763	6,343,612
Total Demand - \$	<u>2,622,042</u>	<u>2,615,935</u>	<u>3,919,008</u>	<u>3,905,996</u>	<u>3,724,153</u>	<u>3,711,963</u>	<u>3,724,153</u>	<u>3,718,070</u>	<u>27,941,319</u>
Commodity - \$ - PA	7,081,010	8,140,983	7,444,763	4,155,849	5,768,632	5,933,786	3,792,713	3,955,470	46,273,208
Net Commodity - \$	<u>7,081,010</u>	<u>8,140,983</u>	<u>7,444,763</u>	<u>4,155,849</u>	<u>5,768,632</u>	<u>5,933,786</u>	<u>3,792,713</u>	<u>3,955,470</u>	<u>46,273,208</u>
Total Cost - \$	<u>9,703,052</u>	<u>10,756,918</u>	<u>11,363,771</u>	<u>8,061,845</u>	<u>9,492,785</u>	<u>9,645,749</u>	<u>7,516,866</u>	<u>7,673,540</u>	<u>74,214,527</u>

¹ See Exhibit 23, Schedule 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Details of Storage
Eight Months Ended July 2024

	2023	2024							
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Total</u>
Rental Cost*									
Demand	1,145,141	1,145,141	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	12,344,626
Commodity	38,530	89,582	59,632	73,343	13,726	47,440	46,256	47,886	416,395
Transportation Cost									
Demand	185,091	185,091	185,091	185,091	92,550	92,550	92,550	92,550	1,110,564
Commodity	3,342	1,490	497	1,987	55	1,082	1,163	1,233	10,849
Gas Cost									
Demand	2,406,887	5,001,112	3,838,097	4,832,366	(979,236)	(3,129,017)	(3,072,454)	(3,177,003)	5,720,752
Commodity	2,444,301	5,078,852	3,897,758	4,907,483	(994,457)	(3,177,655)	(3,120,214)	(3,226,388)	5,809,680
TOTAL COSTS									
Demand	3,737,119	6,331,344	5,698,912	6,693,181	789,038	(1,360,743)	(1,304,180)	(1,408,729)	19,175,942
Commodity	2,486,173	5,169,924	3,957,887	4,982,813	(980,676)	(3,129,133)	(3,072,795)	(3,177,269)	6,236,924
TOTAL	6,223,292	11,501,268	9,656,799	11,675,994	(191,638)	(4,489,876)	(4,376,975)	(4,585,998)	25,412,866

See Exhibit 23, Schedule 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Detail of Costs Related to Peoples Gas Company
Eight Months Ended July 2024

	2023	2024							
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Total</u>
Mcf	955	1,055	864	804	467	240	142	120	4,647
Amount - \$	13,017	13,225	10,675	9,954	4,276	2,136	1,350	1,074	55,706

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Detail of Capacity Release
Eight Months Ended July 2024

	2023	2024							
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Total</u>
PA. Capacity Release	213,983	197,793	184,666	177,762	132,060	121,261	131,179	121,068	1,279,771
PA Customer Wide Choice Capacity Release	167,898	167,898	167,898	167,898	167,898	167,898	167,898	167,898	1,343,187
PA Capacity Release - \$	381,881	365,691	352,564	345,660	299,959	289,160	299,077	288,966	2,622,958

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Temperature Swing/ Peaking Capacity Costs
Eight Months Ended July 2024

	2023	2024							
	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Total</u>
NFGSC EFT Capacity (Dth)	54,111	54,111	54,111	54,111	54,111	54,111	54,111	54,111	
Rate (\$ / Dth)	5.1512	5.1512	8.9534	8.9534	8.9534	8.9534	8.9534	8.9534	
Amount (\$)	278,737	278,737	484,477	484,477	484,477	484,477	484,477	484,477	3,464,336
NFGSC ESS Delivery (Dth)	43,445	43,445	43,445	43,445	43,445	43,445	43,445	43,445	
Rate (\$ / Dth)	2.7643	2.7643	4.2337	4.2337	4.2337	4.2337	4.2337	4.2337	
Amount (\$)	120,095	120,095	183,933	183,933	183,933	183,933	183,933	183,933	1,343,788
NFGSC ESS Capacity (Dth)	2,027,925	2,027,925	2,027,925	2,027,925	2,027,925	2,027,925	2,027,925	2,027,925	
Rate (\$ / Dth)	0.0502	0.0502	0.0748	0.0748	0.0748	0.0748	0.0748	0.0748	
Amount (\$)	101,802	101,802	151,689	151,689	151,689	151,689	151,689	151,689	1,113,738
NFGSC FSS Delivery (Dth)	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	
Rate (\$ / Dth)	2.6536	2.6536	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	
Amount (\$)	28,303	28,303	43,404	43,404	43,404	43,404	43,404	43,404	317,030
NFGSC FSS Capacity (Dth)	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	
Rate (\$ / Dth)	0.0479	0.0479	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713	
Amount (\$)	9,580	9,580	14,260	14,260	14,260	14,260	14,260	14,260	104,720
Grand Total Cost - Distribution Charge (\$)	538,517	538,517	877,763	877,763	877,763	877,763	877,763	877,763	6,343,612

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Summary of Cost of Gas by Gas Supplier and

Transmission of Gas by Local Producers

Twelve Months Ended July 2025

<u>Supplier</u>	<u>Projected Quantity Purchased</u> (Mcf)	<u>Commodity Cost</u> (\$)	<u>Demand Cost Natural Gas Supply</u> (\$)	<u>Demand Cost Distribution Charge</u> (\$)	<u>Total Projected Cost</u> (\$)
Upstream Purchases	21,723,702	74,301,334	33,999,261	10,519,956	118,820,551
Storage		2,146,105	22,322,889	0	24,468,994
Transportation Credit			(5,210,408)	0	(5,210,408)
Capacity Release Credit			(6,904,343)	0	(6,904,343)
Local Production	100,860	299,073			299,073
Peoples Gas Company	5,583	61,620			61,620
Subtotal	21,830,145	76,808,132	44,207,399	10,519,956	131,535,487
Credit - Line Hits		<u>(4,476)</u>			<u>(4,476)</u>
Total		<u>76,803,656</u>			<u>131,531,011</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Summary of Cost of Gas by Gas Supplier

Twelve Months Ended July 2025

<u>Supplier</u>	<u>Projected Quantity Purchased</u> (Mcf)	<u>Commodity Cost</u> (\$)	<u>Demand Cost Natural Gas Supply</u> (\$)	<u>Demand Cost Distribution Charge</u> (\$)	<u>Total Projected Cost</u> (\$)
Upstream					
August 2024	379,929	3,830,179	2,859,681	876,663	7,566,523
September	379,802	3,278,951	2,871,871	876,663	7,027,485
October	1,081,146	4,403,036	2,859,681	876,663	8,139,380
November	2,044,376	3,673,829	2,841,407	876,663	7,391,899
December	3,068,945	8,105,623	2,792,644	876,663	11,774,930
January 2025	4,220,897	10,282,215	2,823,109	876,663	13,981,987
February	3,632,670	9,490,216	2,817,025	876,663	13,183,904
March	3,138,344	5,948,466	2,804,834	876,663	9,629,963
April	1,849,077	6,771,897	2,835,300	876,663	10,483,860
May	1,162,359	7,874,372	2,823,109	876,663	11,574,144
June	384,993	5,127,201	2,835,300	876,663	8,839,164
July	381,164	5,515,349	2,835,300	876,663	9,227,312
Total	21,723,702	74,301,334	33,999,261	10,519,956	118,820,551

See Exhibit 23, Schedule 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Summary of Cost of Gas by Gas Supplier

Twelve Months Ended July 2025

<u>Supplier</u>	Projected Quantity <u>Purchased</u> (Mcf)	Commodity <u>Cost</u> (\$)	Total Projected <u>Cost</u> (\$)
Local Production			
August 2024	8,566	20,364	20,364
September	8,290	19,093	19,093
October	8,566	20,074	20,074
November	8,290	23,009	23,009
December	8,566	27,488	27,488
January 2025	8,566	31,597	31,597
February	7,738	27,820	27,820
March	8,566	27,759	27,759
April	8,290	23,675	23,675
May	8,566	24,528	24,528
June	8,290	25,436	25,436
July	8,566	28,230	28,230
Total	100,860	299,073	299,073

See Exhibit 23, Schedule 2

Exhibit 24, Appendix 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Summary of Credit Due to Line Hits
Twelve Months Ended July 2025

	2024	2025											
	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Total</u>
Line Hits (Credit) Amount - \$	892	16	1,225	638	107	368	50	292	1	45	365	479	4,476

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Details of Upstream Purchases (Including Transportation) ¹
Twelve Months Ended July 2025

	2024	2025											
	August	September	October	November	December	January	February	March	April	May	June	July	Total
Purchase Volume - Dth	1,504,082	1,586,177	2,118,028	1,032,687	1,603,292	1,717,052	1,605,209	1,221,425	2,031,281	2,118,571	1,622,617	1,627,716	19,788,137
City Gate NFGSC Volume - Dth	0	0	91,668	297,540	676,408	737,899	666,490	307,458	0	365,422	0	0	3,142,885
Storage Volume - Dth	(1,104,776)	(1,187,005)	(1,073,412)	818,412	945,761	1,981,211	1,546,237	1,769,517	(87,901)	(1,262,354)	(1,217,989)	(1,227,112)	(99,411)
Total Volume - Dth	399,306	399,172	1,136,284	2,148,639	3,225,461	4,436,162	3,817,936	3,298,400	1,943,380	1,221,639	404,628	400,604	22,831,611
Conversion Factor	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	1.0510	
Total Volume - Mcf	379,929	379,802	1,081,146	2,044,376	3,068,945	4,220,897	3,632,670	3,138,344	1,849,077	1,162,359	384,993	381,164	21,723,702
Net Purchases - Mcf	379,929	379,802	1,081,146	2,044,376	3,068,945	4,220,897	3,632,670	3,138,344	1,849,077	1,162,359	384,993	381,164	21,723,702
Demand - Natural Gas Supply - \$	2,859,681	2,871,871	2,859,681	2,841,407	2,792,644	2,823,109	2,817,025	2,804,834	2,835,300	2,823,109	2,835,300	2,835,300	33,999,261
Demand - Distribution Charge - \$	876,663	876,663	876,663	876,663	876,663	876,663	876,663	876,663	876,663	876,663	876,663	876,663	10,519,956
Total Demand - \$	3,736,344	3,748,534	3,736,344	3,718,070	3,669,307	3,699,772	3,693,688	3,681,497	3,711,963	3,699,772	3,711,963	3,711,963	44,519,217
Commodity - \$ - PA	3,830,179	3,278,951	4,403,036	3,673,829	8,105,623	10,282,215	9,490,216	5,948,466	6,771,897	7,874,372	5,127,201	5,515,349	74,301,334
Net Commodity - \$	3,830,179	3,278,951	4,403,036	3,673,829	8,105,623	10,282,215	9,490,216	5,948,466	6,771,897	7,874,372	5,127,201	5,515,349	74,301,334
Total Cost - \$	7,566,523	7,027,485	8,139,380	7,391,899	11,774,930	13,981,987	13,183,904	9,629,963	10,483,860	11,574,144	8,839,164	9,227,312	118,820,551

¹ See Exhibit 23, Schedule 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Details of Storage
Twelve Months Ended July 2025

	2024	2025											
	August	September	October	November	December	January	February	March	April	May	June	July	Total
Rental Cost													
Demand	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	20,108,688
Commodity	43,945	45,228	41,307	31,174	37,270	75,959	59,557	68,565	2,120	48,639	46,644	47,551	547,959
Transportation Cost													
Demand	92,550	92,550	185,091	185,091	185,091	185,091	185,091	185,091	92,550	92,550	92,550	92,550	1,665,846
Commodity	1,224	1,143	715	901	376	2,697	1,987	1,788	897	1,082	1,163	920	14,893
Gas Cost													
Demand	(2,809,847)	(3,018,433)	(3,067,276)	2,322,241	2,743,411	5,695,125	4,444,183	5,083,515	(252,502)	(3,606,703)	(3,479,720)	(3,505,639)	548,355
Commodity	(2,853,525)	(3,065,353)	(3,608,661)	2,732,125	3,227,632	6,700,335	5,228,597	5,980,774	(297,069)	(4,243,300)	(4,093,904)	(4,124,398)	1,583,253
TOTAL COSTS													
Demand	(1,041,573)	(1,250,159)	(1,206,461)	4,183,056	4,604,226	7,555,940	6,304,998	6,944,330	1,515,772	(1,838,429)	(1,711,446)	(1,737,365)	22,322,889
Commodity	(2,808,356)	(3,018,982)	(3,566,639)	2,764,200	3,265,278	6,778,991	5,290,141	6,051,127	(294,052)	(4,193,579)	(4,046,097)	(4,075,927)	2,146,105
TOTAL	(3,849,929)	(4,269,141)	(4,773,100)	6,947,256	7,869,504	14,334,931	11,595,139	12,995,457	1,221,720	(6,032,008)	(5,757,543)	(5,813,292)	24,468,994

See Exhibit 23, Schedule 1

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Detail of Costs Related to Peoples Gas Company
Twelve Months Ended July 2025

	2024	2025											
	<u>August</u>	<u>September</u>	<u>October</u>	<u>November</u>	<u>December</u>	<u>January</u>	<u>February</u>	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Total</u>
Mcf	116	111	224	485	955	1,055	864	804	467	240	142	120	5,583
Amount - \$	1,007	976	1,410	2,520	13,017	13,225	10,675	9,954	4,276	2,136	1,350	1,074	61,620

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Detail of Capacity Release Credits
Twelve Months Ended July 2025

	2024	2025											
	August	September	October	November	December	January	February	March	April	May	June	July	Total
PA Capacity Release	115,648	114,696	124,451	165,953	213,983	197,793	184,666	177,762	132,060	121,261	131,179	121,068	1,800,518
PA Customer Wide Choice Capacity Release	425,318	425,318	425,318	425,318	425,318	425,318	425,318	425,318	425,318	425,318	425,318	425,318	5,103,825
Capacity Release Credit - \$	540,967	540,014	549,769	591,271	639,301	623,111	609,984	603,080	557,379	546,580	556,497	546,386	6,904,343

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
 Pennsylvania Division
 Temperature Swing / Peaking Capacity Costs
 Twelve Months Ended July 2025

[illegible]

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

**Response of National Fuel Gas Distribution Corporation to the Commission's
Filing Requirement Codified at 52 Pa. Code Section 53.64(c)(1) --**

A complete list . . . of . . . the quantity and price of gas delivered, produced, transported or stored, maximum daily quantity levels, maximum annual quantity levels, a detailed description of warrantee or penalty provisions, including liquidated damages, take or pay provisions or minimum bill or take provisions of the purchases, balancing provisions and copies of Federal tariffs and contract provisions relating to the purchases-including demand and commodity components. With regard to each contemplated future source of supply, production, transportation or storage, during each of the next 20 months for each source, provide the name of the source, the maximum daily quantity, the maximum annual quantity, the minimum take levels, a detailed description of warrantee or penalty provisions, including liquidated damages, take or pay provisions or minimum bill or take provisions of the purchases, balancing provisions and contractual or tariffed terms of the purchases, copies of applicable Federal tariffs, the expiration date of each contract, the date when each contract was most recently negotiated and the details of the negotiation-such as meeting held, offers made, and changes in contractual obligation - and whether current proceedings, negotiations or renegotiations are pending before the Federal Energy Regulatory Commission, and the like, to modify the price, quantity or another condition of purchase, and if so, the details of the proceedings, negotiations or renegotiations. Gas supply sources which individually represent less than 3% of the total system supply may be shown collectively, such as other local gas purchases.

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II. GAS PURCHASE CONTRACTS/AGREEMENTS

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- B.** Term Gas Purchases
- C.** Spot Gas Purchases
- D.** Market Area Purchases
- E.** Non-Firm Local Production Gas Purchases
- F.** Gas Purchases pursuant to Tariff

I. RATE DESIGN

A. Pipeline Service Contracts In General

During the historic period through November 30, 2023, the majority of gas supplies for sale to customers of Distribution were transported through National Fuel Gas Supply Corporation (“Supply” or “NFGSC”), Tennessee Gas Pipeline Company, L.L.C. (“Tennessee” or “TGP”), Texas Eastern Transmission, LP (“Texas Eastern” or “TETCO”) and Columbia Gas Transmission, LLC (“Columbia”). In most instances, gas supplies are transported to facilities of Supply by the other pipelines and redelivered by Supply to Distribution for its customers. Supply owns and operates extensive pipeline and storage facilities in Pennsylvania and New York and is subject to the jurisdiction of the Federal Energy Regulatory Commission (“FERC”).

1 Most interstate pipelines have primarily designed their rates on a straight-
2 fixed variable (“SFV”) basis, “... assigning all fixed costs related to transportation
3 to the reservation charge.” See Order No. 636, FERC Statutes and Regulations,
4 Regulations Preambles ¶¶30,939 at 30,434 (1992). Therefore, Distribution pays
5 nearly all the costs of its contracted pipeline transportation and storage through
6 demand charges. A very small portion of the costs of these services is paid on a
7 volumetric basis. An exception to this has been Tennessee. Pursuant to a
8 Settlement among the parties in its most recent rate case, Tennessee charges SFV
9 designed rates applicable for zones 0, 1, 2 and 3, and modified-fixed variable
10 (“MFV”) rates applicable for zones 4, 5 and 6. TGP’s MFV rates collect a
11 portion of fixed costs through the commodity charge.

12 **B. Transportation, Storage and Winter Gas Calls Capacity**
13 **Contracts**

14 Distribution continually evaluates its market needs and available
15 opportunities to adjust its capacity mix and gas source diversity, seeking to
16 achieve the least cost for customers while maintaining an acceptable level of
17 reliability. All of Distribution's pipeline and storage service contracts contain
18 right of first refusal contractual provision that allows the Company to consider
19 various options to retain or replace its existing capacity prior its contact
20 termination. Distribution’s current upstream transportation, storage and winter
21 gas calls capacity including notice dates and contract extension dates is
22 summarized on PGC Exhibit No. 4-A. Adjustments to transportation or storage

1 capacities that are expected to occur during the next 20 months are explained in
2 PGC Exhibit No. 8. Significant adjustments to existing capacity are as follows:

3 **TGP**

4 Distribution previously extended the term of its FT-A Service
5 Contract No. 2752 through March 31, 2027, which included 2 options to continue
6 shortening existing long-haul capacity paths from the Gulf production region to
7 short-haul capacity paths from Appalachian production region. See the table
8 below for the first option exercised during the historic period.

Long-haul Reduction Optionality				
Option	Option Exercise Date	Effective Date	Long-haul Capacity Quantity	Short-haul Capacity
Current			17,500	56,500
1	6/20/2023	4/1/2024	8,750	65,250

9

10 **C. No Cost Gas Exchange Agreements and Other Utility**
11 **Purchases**

12 Distribution has two Exchange Agreements with other Pennsylvania local
13 distribution companies. These companies are Columbia Gas of Pennsylvania, Inc.
14 and UGI Central Penn Gas, Inc. These agreements have allowed Distribution and
15 its counterparties to avoid replacing extensive, aging pipeline facilities to remote
16 pockets of customers by instead constructing more limited, less costly, facilities to
17 connect to the system of the nearby, counterparty utility.

18 Pursuant to the agreements, each day, each company takes the volume of
19 gas that it requires from the other company. The agreements do not contemplate a

1 sale, but an even exchange of gas between parties. As such, Distribution and its
2 counterparties do not charge each other for the gas they provide to each other, as
3 they receive approximately equal volumes of gas in return on a daily basis, or
4 over the course of time. There are no reservation-of-capacity fees, volumetric
5 commodity fees or any other fees. The on-going exchange balance with each
6 company is monitored on a monthly basis and, if necessary, trued-up via
7 additional deliveries at an exchange or a balancing point. These agreements have
8 no set termination dates.

9 Details regarding the volumes of gas exchanged are reported in PGC Exhibit
10 No. 1, Schedule 1, Sheet 6.

11 In addition to the no cost exchange agreements, Distribution also relies on
12 firm sales service from Peoples Natural Gas Company, LLC at two interconnections
13 where Distribution avoided extensive pipeline replacement of existing aging system
14 segments to serve its customers.

15 **D. Small Aggregation Transportation Customer (“SATC”) Capacity**

16 As of November 2023, eighteen SATC suppliers take release of
17 Distribution’s Supply EFT and ESS and TGP FT-A zone 4 capacities.

18 **II. GAS PURCHASE CONTRACTS/AGREEMENTS**

19 Distribution predominately negotiates with suppliers for firm gas supplies
20 and rarely agrees to interruptible gas supply terms. Distribution purchases gas on
21 a Term (delivery period greater than one month) delivery basis and a Spot
22 (delivery period equal to, or less than, one month) delivery basis. This section

1 separately describes the contract type, negotiation and purchase activities of Term
2 and Spot purchases.

3 **A. Take or Pay or Minimum Bill Provisions**

4 As Distribution contracts for gas supplies, it has and will continue to avoid
5 take-or-pay provisions and minimum commodity bill provisions. Distribution
6 does have Term gas supply contracts under which it exercises its rights to fix or
7 cap prices in the forward market and, as a result, these actions trigger must take,
8 fixed volume requirements. Failure to accept delivery of these fixed volumes
9 from a supplier would possibly result in Distribution paying the Supplier for
10 supplies not received. Accordingly, the Company limits such must take, fixed
11 volumes and has not been subjected to such payments. The Company's Gas Cost
12 Management Plan ("Plan") mitigate this risk by limiting the quantity of fixed or
13 cap priced supplies in its gas supply portfolio. These contracts are discussed here
14 and in PGC Exhibit No. 8. Distribution also has other Term gas supply contracts
15 that contain demand charges. The demand charge paid reflects a payment for the
16 firm commitment by those suppliers. A "keep-whole" charge provision
17 negotiated with some Term suppliers is specified in their contracts. The keep-
18 whole charges provide Distribution the right to use flexibility in the contract and
19 to pay the Supplier the cost of doing so at the time and for the amount of
20 flexibility used. Distribution can generally avoid exercising this contract right by
21 incorporating adequate daily flexibility in the planned purchases. Such charges

1 allow the Company to avoid significant demand charges, which would otherwise
2 be necessary to reserve such flexibility.

3 **B. Term Gas Purchases**

4 In general, under its standard long-term firm contracts (“Master Gas
5 Purchase Contract” or “Master Contract” and North American Energy Standards
6 Board (“NAESB”) Contract) Distribution pays a commodity price that is
7 generally based upon published Spot price indices, NYMEX Settlement or a
8 negotiated cash price (“Cash”). Under most such contracts, Distribution pays a
9 demand charge for the firm dedication and/or flexible supply of the gas.
10 Distribution strives to negotiate strong liquidated damages language in its
11 contracts in order to encourage suppliers to deliver the contracted-for volumes.
12 Term supply arrangements are typically negotiated with take or release flexibility,
13 providing Distribution with the ability either to take the gas monthly or daily or to
14 release the gas to the supplier.

15 **1. Negotiation Process**

16 During the summer prior to winter delivery, Distribution begins securing
17 gas supplies on a Term basis, utilizing a competitive bidding process, when and
18 where it concludes that Term contracts are necessary to ensure reliable deliveries.
19 Gas supply availability is evaluated in order; first to assure adequate delivery
20 quantities; second to determine whether premiums for Term supplies are
21 necessary; third to determine the current market price for the premiums; and
22 finally to determine whether Spot supplies are available, and, if so, whether they

1 are sufficiently abundant to assure the same level of reliability without such
2 premiums (or demand charges). This evaluation order may vary by season.

3 Distribution develops and forwards a Request for Proposal (“RFP”)
4 specifying the commercial terms of the proposed purchase transactions to the
5 appropriate suppliers. Suppliers submit their bids to Distribution for review.
6 Distribution then narrows the search to a short list of producers and marketers
7 based upon the criteria set forth in the RFPs. Distribution’s primary goal is to
8 ensure reliability of supply and availability of competitive pricing. Any past
9 working relationship between the supplier and Distribution is also a consideration.
10 Following discussions with these potential suppliers, Distribution selects specific
11 suppliers, and final contract terms are negotiated and agreed to between the
12 parties.

13 **2. Contract Details**

14 Distribution currently has thirty-three (33) Term supply contracts. Current
15 Term supply arrangements made pursuant to these contracts are noted in PGC
16 Exhibit No. 4-B.

17 Distribution has been able to contract for winter supplies at desirable
18 points generally with very small premiums. At times Distribution may elect to
19 replace some Term supplies with lower cost monthly Spot purchases. In these
20 instances, Distribution utilized its take-or-release option prior to the beginning of
21 each winter month to convert certain monthly Term deliveries to a Term daily call
22 option and replace those deliveries with lower cost market area monthly Spot

1 purchases. Distribution's ratepayers realize the market area savings without
2 jeopardizing winter supply reliability. A description of the purchases made under
3 the Term and Spot supply contracts for this past winter is provided below.

4 **3. Recent Purchases**

5 **For the winter of 2022 – 2023 (November 2022 through March 2023),**
6 Distribution's Northeast Shale purchases accounted for 100% of the total
7 supplies. Distribution purchased an average total of approximately 56,800Dth/day
8 from the following categories of gas supplies:

9 Forward fixed price gas –

10 Approximately 13,600 Dth/day purchased from five suppliers.

11 Monthly priced gas (Cash, NYMEX or Index) –

12 Approximately 16,400 Dth/day purchased from four Term
13 suppliers and approximately 1,400 Dth/day purchased in the
14 monthly Spot market from two Spot suppliers.

15 Daily priced gas (Cash and Index) –

16 Approximately 5,600 Dth/day of daily priced gas was elected from
17 six Term suppliers and 19,800 Dth/day was purchased in the daily
18 Spot market from eight Spot suppliers.

19 **For the summer of 2023 (April 2023 through October 2023),**

20 Distribution purchased 100% of the approximately 55,000 Dth/day of Northeast
21 Shale produced supplies from a variety of suppliers at market area receipt points
22 priced in the following categories:

1 Forward fixed price gas – 8,000 Dth/day

2 Monthly priced Term gas (Index) – 2,500 Dth/day

3 Monthly priced Spot gas (Cash, NYMEX or Index) –19,800 Dth/day

4 Daily priced gas (Cash and Index) –24,700 Dth/day

5 **4. Recent Negotiations or Renegotiations**

6 **For the winter of 2023 – 2024 (November 2023 through March 2024),**

7 in response to Distribution's requests for winter supplies, ten (10) bidders
8 submitted offers. The best offers selected, combined with previously contracted
9 supplies, resulted in Distribution entering into agreements with suppliers to
10 purchase up to approximately 113,000 Dth/day of firm gas supplies. Four
11 suppliers are providing approximately 18,000 Dth/day of firm fixed price base
12 load gas supplies, two suppliers are providing 8,000 Dth/day of firm index price
13 base load gas supplies, and six suppliers are providing approximately 51,000
14 Dth/day of firm gas supplies with take-or-release flexibility. Distribution can elect
15 to price these supplies on either first of the month pricing (Index, Cash or
16 NYMEX) or daily pricing (Index or Cash) depending on the desired flexibility
17 during the delivery month.

18 Distribution anticipates opportunities to replace some monthly and daily
19 Term supplies with lower cost monthly and daily Spot supplies during this winter
20 period. Take-or-release upstream firm supply contracts with low demand charges
21 provide backup supplies should these Spot producers fail to deliver.

22 Lastly, Distribution entered into five winter gas call agreements for up to

1 36,000 Dth/day.

2 **C. Spot Gas Purchases**

3 Distribution purchases Spot gas from time to time on a daily or month-to-
4 month basis at negotiated market prices such as NYMEX Settlement adjusted by
5 an agreed upon “basis”, Cash or published Spot indices. Spot purchases are
6 generally entered into under the standardized contracts developed by the Gas
7 Industry Standards Board (“GISB”) and the NAESB for use in the natural gas
8 industry. The commercial terms of each purchase are specified and confirmed by
9 both parties using a standardized transaction confirmation.

10 Spot contracts are used primarily during non-winter months for daily or
11 monthly Spot purchases when flexibility is required, and the added reliability
12 obtained with a long-term firm contract is less of an issue. To achieve market
13 area savings without jeopardizing winter supply reliability, Distribution may
14 suspend winter Term purchases by electing the daily take-or-release option rather
15 than base loading a Term supply contract for a given delivery month and
16 replacing that gas delivery with an alternate lower-cost monthly Spot purchase,
17 adhering to the purchase diversification guidelines prescribed in the Plan. To
18 ensure reliable delivery to the ratepayer, Distribution may revert to daily
19 nomination of the Term contract for the duration of an unlikely interruption of
20 these Spot purchases.

21 Spot contracts were used to purchase approximately 61% of system gas
22 purchased during the period beginning December 1, 2022, and ending November

1 30, 2023.

2 **D. Market Area Purchases**

3 Located in the market area, the Marcellus and Utica producing formations
4 underlie a large geographic area containing numerous pipeline interconnects and
5 their associated market area trading hubs. Northeast production has exceeded 36
6 Bcf/day resulting in many pipelines reversing flow directions to transport
7 abundant, low cost Northeast Shale gas from the Northeast to other regions of
8 North America. Distribution continues to categorize all gas purchased in the
9 northeast as being either Marcellus or Utica Shale produced gas. Since May
10 2015, 100% of Distribution's supply has been purchased in the northeast market
11 area. Distribution purchases significant quantities of gas at citygate receipt points
12 into its Supply EFT capacity and at pooling receipt points within TGP's zone 4
13 region, TETCO's M2 region, and Columbia's reticulated system. TGP's pooling
14 point at station 219, situated where the 300 line splits from the 200 line in
15 Western Pennsylvania, is an effective market area pooling point for Distribution
16 to purchase supplies sourced from multiple production basins including the
17 Marcellus and Utica shale basins. Distribution's purchases from these market
18 area receipt points and pools accounted for 100% of its purchases during the
19 historic period.

1 **E. Non-Firm Local Production Gas Purchases**

2 Distribution purchased during the historic period (November estimated),
3 non-firm local production and Appalachian gas delivered into its system and
4 Supply's system as follows:

- 5 1. 88,250 Dth pursuant to "life-of-reserves" or "dedicated" contracts
6 priced at an Appalachian index ("AI"),
7 2. 142,804 Dth pursuant to excess gas purchase and/or NAESB gas
8 purchase contracts priced at 80% of the AI.

9 The AI is the simple average of the first of the month index prices for gas
10 delivered to Dominion Energy Transmission, Inc. and to Columbia.

11 **F. Gas Purchases pursuant to Tariff**

12 Distribution purchased, pursuant to its tariff during the historic period
13 (excluding the month of November for which data is not yet available or
14 estimable), 550,321 Mcf of PA Suppliers' Surplus Imbalances and 899 Mcf of
15 SATC supplier storage gas.

Transportation Capacity						
Pipeline & Rate Schedule	Contract	Dth/day	Contract Term	Contract Term Notice Period	Notice Date ⁽¹⁾	Contract End Date With Extension
Columbia Gas Transmission, Inc.						
FTS	80562	1,748	11/01/2004-3/31/2024	6 months	10/31/2023	3/31/2026
SST	80564	18,417	11/01/2004-3/31/2024	6 months	10/31/2023	3/31/2026
National Fuel Gas Supply Corp.						
EFT	E00528	291,130	8/1/1993 - 3/31/2024	12 months	3/31/2023	11/9/2026
EFT	E11178	9,000	4/1/2008 - 3/31/2024	6 months	10/31/2023	3/31/2025
EFT	E11969	10,000	11/1/2014 - 3/31/2024	6 months	10/31/2023	3/31/2025
EFT	E12642	10,000	11/1/2021 - 3/31/2024	12 months	3/31/2023	3/31/2025
FT	F12198	31,000	11/1/2017 - 3/31/2028	12 months		
FST	N12464	14,000	4/1/2020 - 3/31/2026	12 months		
Tennessee Gas Pipeline Company						
FT-A	2752	74,000	9/1/1993 - 3/31/2027	12 months		
Texas Eastern Transmission LP						
FT-1	911316	10,000	11/1/2016 - 10/31/2024	12 months	10/31/2023	10/31/2025

Storage Capacity							
Pipeline & Rate Schedule	Contract	Capacity	Dth/day	Contract Term	Contract Term Notice Period	Notice Date ⁽¹⁾	Contract Term With Extension
Columbia Gas Transmission, Inc.							
FSS	80566	564,031	18,417	11/1/1993-3/31/2024	6 months	10/31/2023	3/31/2026
National Fuel Gas Supply Corp.							
ESS**	G00539	8,755,100	187,563	8/1/1993 - 3/31/2024	12 months	3/31/2023	11/9/2026
FSS	O02432	200,000	10,666	4/1/2010 - 3/31/2024	6 months	10/31/2023	3/31/2025
FSS	O12463	651,274	14,000	4/1/2020 - 3/31/2026	12 months		

Winter Gas Calls			
Purchase Point	Dth/day	Contract Term	
NFGSC city gate receipt points	36,000	11/1/2023 - 3/31/2024	

⁽¹⁾ Notice date to extend contract exercised during historical period

National Fuel Gas Distribution Corporation-Contract Terms
Firm Gas Purchase Contracts
Master & NAESB Gas Purchase Contract(s)

Supplier	Contract Beginning Date	Current Purchase Term(s)
A	10/1/2003	11/1/2023-3/31/2024
B	7/1/1998	11/1/2023-3/31/2024
C	5/1/2013	11/1/2023-3/31/2024
D	10/1/2010	11/1/2023-3/31/2024
F	3/28/2009	11/1/2023-3/31/2024
G	6/24/2020	11/1/2023-3/31/2024
H	2/1/2022	11/1/2023-3/31/2024
I	7/1/1997	11/1/2023-3/31/2024
K	9/4/2019	11/1/2023-3/31/2024
J	9/15/2011	11/1/2023-3/31/2024
E	5/1/2009	No Purchases Currently
L	7/13/2016	No Purchases Currently
M	4/30/2011	No Purchases Currently
N	10/28/2005	No Purchases Currently
O	9/20/2013	No Purchases Currently
P	10/29/2004	No Purchases Currently
Q	11/28/2014	No Purchases Currently
R	9/1/2013	No Purchases Currently
S	1/1/2018	No Purchases Currently
T	9/1/2015	No Purchases Currently
U	8/1/2010	No Purchases Currently
V	1/9/2017	No Purchases Currently
W	7/29/2013	No Purchases Currently
X	1/1/2001	No Purchases Currently
Y	8/20/2009	No Purchases Currently
Z	7/1/1998	No Purchases Currently
AA	8/15/2009	No Purchases Currently
AB	7/6/2006	No Purchases Currently
AC	6/6/2003	No Purchases Currently
AD	5/1/2009	No Purchases Currently
AE	6/15/1998	No Purchases Currently
AF	3/15/2023	No Purchases Currently
AG	5/15/2023	No Purchases Currently

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

53.64 (c) (3) A complete listing of sources of gas supply, transportation or storage and their costs, including shut-in and curtailed sources of supply, both inside and outside this Commonwealth considered by or offered to the utility but not chosen for use during the past 12 months, which 12-month period shall end 2 months prior to the date of the tariff filing, and reasons why the gas supply, transportation or storage was not selected for use as part of the utility's supply mix. A similar listing of gas sources, transportation or storage and associated projected costs offered or considered but not chosen to meet supply for the next 20 months, along with reasons for nonselection.

Details of the gas supply, transportation and storage that Distribution acquired during the historic period and for the next 20 months are provided in PGC Exhibit Nos. 4 and 8. Distribution chooses gas supplies, transportation and storage based upon their level of reliability, operational effectiveness and cost.

1

2

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

3 53.64(c)(4) An annotated listing of Federal Energy Regulatory Commission or other
4 relevant non-Commission proceedings, including legal action necessary to relieve the
5 utility from existing contract terms which are or may be adverse to the interests of its
6 ratepayers, which affect the cost of the utility's gas supply, transportation or storage or
7 which might have an impact on the utility's efforts to provide its customers with reasonable
8 gas service at the lowest price possible. This list shall include docket numbers and shall
9 summarize what has transpired in the cases, and the degree of participation, if any, which
10 the utility has had in the cases. The initial list filed under this paragraph shall include all
11 cases for the past 3 years. Subsequent lists need only update prior lists and add new
12 cases.

13 A. Distribution's Participation in FERC Proceedings

14 Distribution has specific capacity on the following interstate pipelines to serve its
15 Pennsylvania end-users: Columbia Gas Transmission, LLC ("Columbia"), National Fuel
16 Gas Supply Corporation ("Supply"), Tennessee Gas Pipeline Company, L.L.C.
17 ("Tennessee"), and Texas Eastern Transmission, LP ("Texas Eastern").

18 Distribution actively participates at the Federal Energy Regulatory Commission
19 ("FERC") in proceedings involving the individual pipelines on which Distribution
20 transports and/or stores gas, as well as generic industry-wide proceedings that may have
21 an impact on Distribution and its customers.

22 Distribution actively represents its positions at the FERC, asserting its interests as a
23 local distribution company in all cases where such action is appropriate, including FERC
24 rulemakings, generic proceedings and the rate and certificate proceedings of Distribution's
25 upstream pipelines, including Supply. In this regard, Distribution's Deputy General
26 Counsel and Chief Regulatory Counsel, Regulatory Analyst II, and Senior Counsel, as
27 well as other regulatory and gas supply personnel in the Gas Supply Administration, Rates

1 and Regulatory Affairs, and Legal Departments, are responsible for identifying and/or
2 reviewing proceedings at FERC that affect or potentially affect Distribution and its
3 customers. When such a proceeding is identified, Distribution intervenes and participates
4 to ensure appropriate representation of Distribution and its customers. Such participation
5 may include attending and participating in customer meetings and public conferences,
6 presenting comments, and/or filing formal pleadings. Set forth at PGC Exhibit No. 6-A is
7 a list of FERC proceedings in which Distribution participated during the historical period
8 of December 1, 2022 to November 30, 2023 (“Historical Period”).

9 **1. Individual Pipeline Proceedings at the FERC**

10 During the Historical Period, Distribution participated in individual pipeline
11 proceedings at the FERC. Distribution’s participation in these proceedings focuses upon
12 major rate filings, periodic adjustments to trackers/surcharge mechanisms that impact rates
13 paid by Distribution, various refunds/credits, modifications to pipeline tariff provisions
14 impacting service to Distribution, and construction project/abandonment filings for
15 facilities that potentially impact service to Distribution and other matters that may have a
16 generic policy impact beyond the scope of the pipeline’s filing. In addition, Distribution
17 filed its FERC Form No. 552: Annual Report of Natural Gas Transactions on May 1,
18 2023. Significant filings during the Historical Period are detailed below.

19 **a. Columbia Gas Transmission, LLC**

20 **i. Capital Cost Recovery Mechanism Rate Filings**
21

22 In January 2013, the FERC approved a settlement between Columbia and its
23 customers (“Modernization I Settlement”) in Docket No. RP12-1021 that established a

1 Capital Cost-Recovery Mechanism (“CCRM”) that allows Columbia to make annual
2 limited filings under Section 4 of the Natural Gas Act (“NGA”) to charge an additive
3 capital demand rate (“CCRM Rate”) to recover Columbia’s revenue requirement related to
4 certain eligible projects constructed as part of the modernization efforts between January
5 1, 2013 and December 31, 2017. In February 2016, Columbia filed a related settlement
6 between Columbia and its customers (“Modernization II Settlement”) filed in Docket No.
7 RP16-314 that expanded the scope of the CCRM to include storage facilities and additional
8 transmission facilities and extended the modernization period through December 31, 2021.
9 The Modernization II Settlement was discussed in detail in the 2016 PGC Exhibit No. 6
10 (incorporated herein by reference) and was approved by FERC on March 17, 2016.

11 On March 1, 2023, Columbia submitted its Annual CCRM filing in Docket No.
12 RP23-524 containing revised rates to become effective on April 1, 2023. Based upon
13 contracted reservation quantities, Distribution’s estimated annual CCRM costs were
14 approximately \$80,000.

15 **ii. Operational Transaction Rate Adjustment Filings**
16

17 The Operational Transaction Rate Adjustment (“OTRA”) mechanism was initially
18 proposed by Columbia in April 2012 in Docket No. RP12-605 to recover the costs of
19 certain operational purchases and sales required to ensure a sufficient amount of gas
20 flowing into its system in northern Ohio. The OTRA mechanism is set forth in Section
21 49.4 of Columbia’s Tariff and provides for Columbia to make filings to adjust its OTRA
22 rates twice annually for a summer season (April 1 to October 31) and a winter season
23 (November 1 to March 31). These semiannual filings address both prospective changes in

1 the OTRA rate and prior over or under recoveries. The Modernization II Settlement
2 extended the OTRA mechanism through March 31, 2022.

3 Columbia submitted a filing at the FERC under Docket No. RP23-662 on March
4 31, 2023. The resulting OTRA demand surcharge of \$0.107/Dth, effective May 1, 2023,
5 was a decrease from the previous rate of \$0.206/Dth. The prior OTRA rate was set in
6 Docket No. RP23-126, which became effective on December 1, 2022. Both of the
7 aforementioned filings were approved by the FERC. On November 1, 2023, Columbia
8 filed under Docket No. RP24-121 to adjust the OTRA demand surcharge to \$0.091/Dth,
9 effective December 1, 2023. Based upon contracted reservation quantities, Distribution's
10 estimated OTRA costs during the Historic Period were approximately \$29,000.

11 **iii. Retainage Adjustment Mechanism Filing**

12
13 On February 28, 2023, Columbia submitted its annual Retainage Adjustment
14 Mechanism ("RAM") filing under Docket No. RP23-503 to adjust its retainage percentages
15 taking into account both prospective changes in retainage requirements and unrecovered
16 retainage quantities from the period January 1, 2022 through December 31, 2022. The
17 RAM calculation reflects the retainage percentages required to compensate Columbia for
18 company use gas and lost and unaccounted for volumes. Effective April 1, 2023,
19 transportation retainage increased from 1.831% to 2.132% and Storage Gas Loss Retainage
20 decreased from 0.436% to 0.405%.

21 **iv. Other Columbia Tracker Filings**

22 On February 28, 2023, Columbia filed its annual Electric Power Cost Adjustment
23 ("EPCA") tracker filing under Docket No. RP23-501, increasing the EPCA rate effective

1 April 1, 2023 from \$0.061/Dth to \$0.066/Dth. The EPCA rate permits Columbia to recover
2 electric power costs that are incurred for the compression or processing of natural gas and
3 for company use and operations from its customers. On the same date, Columbia filed its
4 annual Transportation Cost Rate Adjustment ("TCRA") tracker filing under Docket No.
5 RP23-502 increasing the TCRA rate from \$0.401/Dth to \$0.481/Dth; also to be effective
6 April 1, 2023. The TCRA rate permits Columbia to recover transportation costs it incurs
7 on other interstate pipelines not otherwise recovered under the OTRA rates discussed
8 above. Based upon contracted reservation quantities, Distribution's estimated annual
1 EPCA and TCRA costs were approximately \$12,000 and \$90,000, respectively.

2
3 b. National Fuel Gas Supply Corporation

4 **i. Fuel Tracker filing**

5 On February 15, 2023, Supply submitted its fuel tracker filing, which was intended
6 to be effective April 1, 2023, to adjust Supply's Transportation Fuel and Company Use
7 Retention ("TFUR"), Transportation LAUF Retention ("TLAUFR") and Storage
8 Operating and LAUF Retention ("SOLR"). The proposed retainage adjustments in the
9 filing, which were derived from activity during the annual base period commencing
12 January 1, 2022, included a decrease in the TFUR from 0.79% to 0.72%, a decrease
13 in the TLAUFR from 0.36% to 0.10% and a decrease in SOLR from .46% to .45%.

14 **ii. Pipeline Safety & Greenhouse Gas Cost (PS/GHG) Adjustment**
15 **Tracker**

16 On September 29, 2015, Supply filed an uncontested settlement of a rate case
17 extension under Docket No. RP15-1310 ("2015 Rate Settlement") which was addressed in
18 detail in Distribution's PGC Exhibit No. 6 in 2016. The 2015 Rate Settlement
19 allowed Supply to include in its tariff a cost recovery mechanism to recover the cost of

1 service impact associated with Pipeline Safety Costs and Greenhouse Gas Costs (or
2 “PS/GHG Costs”). During the Historic Period, based upon rates set in Docket No. RP22-
3 1268, Distribution was charged approximately \$519,000 in PS/GHG Surcharges. On
4 September 29, 2023, Supply submitted its PS/GHG tracker filing in Docket No. RP23-
5 1097. The new PS/GHG surcharge became effective November 1, 2023.

6 The provisions of the cost recovery mechanism permit Supply to recover via
7 reservation surcharges the cost-of-service effect of two types of costs: i) Pipeline Safety
8 Costs incurred or projected to be incurred by Supply to comply with new legislation and
9 regulatory requirements for pipeline safety and ii) Greenhouse Gas Costs incurred or
10 projected to be incurred by Supply to comply with new legislation and new regulatory
11 requirements.

12 The proposed adjustments, which are in addition to the specified rates then in effect,
13 were as follows:

- 14 1) \$0.1210/Dth Storage PS/GHG Demand/Deliverability Surcharge;
- 15 2) \$0.0017/Dth Storage PS/GHG Capacity Surcharge;
- 16 3) \$0.0701/Dth Transmission PS/GHG Surcharge.

17 The estimated annual impact of the adjustments to the PS/GHG surcharges is
18 approximately \$99,000.

19 **iii. General NGA Section 4 Rate Case**

20 On July 31, 2019, Supply filed a general NGA Section 4 Rate Case in Docket No.
21 RP19-1426 proposing an approximately 48% increase to rates. Distribution engaged in a
22 customer group and a series of settlement negotiations that resulted in a Stipulation &
23 Agreement filed on March 13, 2020. The uncontested settlement was certified by FERC
24 on April 1, 2020 and approved on June 1, 2020. Settled rates went into effect February 1,
25 2020 reflecting an approximate increase to rates of 19%. On February 22, 2022,

1 Supply filed the Period 2 Settlement Rates to be effective April 1, 2022. This filing was
2 approved by the Commission on March 11, 2022. The settled rates remained in effect
3 during the Historical Period.

4 On July 31, 2023, Supply filed a general NGA Section 4 Rate Case in Docket No.
5 RP23-929 proposing an approximately 68% increase to rates. On August 31, 2023, the
6 Commission accepted and suspended the tariff records to be effective February 1, 2024,
7 subject to refund and the outcome of a hearing. Distribution attended the first settlement
8 conference held on October 19, 2023. A second settlement conference will be held on
9 December 13, 2023.

10 **c. Tennessee Gas Pipeline Company, L.L.C.**

11 **i. Fuel Tracker filing**

12 On May 15, 2015, Tennessee filed an offer of settlement ("2015 Settlement") in
13 Docket No. RP15-990 to resolve all rate and other related issues arising from an NGA
14 Section 4 rate case filing in Docket No. RP11-1566 ("2011 Rate Case"). The 2015
15 Settlement included a proposal to establish a fuel and electric power cost recovery
16 mechanism. The 2015 Settlement was approved by Commission Order dated July 1, 2015
17 and became effective on November 1, 2015.

18 On March 1, 2023, Tennessee filed its 2023 Fuel Tracker in Docket No. RP23-
19 522 which became effective April 1, 2023. The purpose of this tracker was recovery of (i)
20 Fuel and Losses for the prospective year based on quantities incurred by Tennessee during
21 the twelve-month period ending December 31, 2022 ("2022 Base Period") and (ii) the
22 balances as of the end of the 2022 Base Period in the applicable Deferred F&LR
23 subaccounts. Similarly, the revised EPCR reflects Tennessee's proposed recovery of (i)
24 Electric Power Costs for the prospective year based on costs incurred by Tennessee during

25 the 2022 Base Period and (ii) the balances as of the end of the 2022 Base Period in the
1 applicable Deferred EPCR subaccounts. In addition, the estimated volumes used to derive
2 the revised F&LR and EPCR reflect actual billable volumes realized by Tennessee during
3 the 2022 Base Period.

4 The fuel retention rate between Zone 4 and Zone 4 decreased from 0.58% to 0.40%.
5 The estimated annual impact of the decreased retainage is approximately \$14,000.

6
On March 1, 2021, Tennessee submitted a tariff filing in Docket RP21-552
7 proposing to modify the methodology used for a fuel and electric power cost recovery
8 mechanism related to a particular expansion project. The project shipper protested the
9 filing, claiming that the methodology proposed by Tennessee was unduly discriminatory,
10 and proposed a revised methodology. Distribution intervened in the matter and joined a
11 customer group of similarly situated local distribution companies. A hearing was held, and
12 the presiding Administrative Law Judge issued an Initial Decision finding Tennessee's
13 proposed tariff records to be just and reasonable. Thereafter, the project shipper filed
14 exceptions to the Initial Decision, and FERC Trial Staff filed a Brief Opposing
15 Exceptions to the Initial Decision. There was no additional activity during the Historical
16 Period, and this matter is currently pending.

17 **ii. Pipeline Safety & Greenhouse Gas Cost (PS/GHG) Adjustment**
18 **Tracker**

12
13 The 2015 Settlement also maintained the Pipeline Safety and Greenhouse Gas Cost
14 Adjustment Mechanism implemented as part of the 2011 Rate Case. During the Historic
15 Period, based upon rates set in Docket No. RP22-1245, Distribution was charged
16 approximately \$55,000 in PS/GHG Surcharges. On September 29, 2023 Tennessee filed to
17 increase their PS/GHG Reservation Surcharges by \$0.0005/Dth to \$0.0462/Dth and

18 PS/GHG Commodity Surcharges by \$0.0001/Dth to \$0.0019/Dth effective November 1,
1 2023. The filing reflected Tennessee’s proposed recovery of (i) costs projected to be
2 incurred by Tennessee during an Annual Period from November 1, 2023 through October
3 31, 2024 and (ii) costs incurred or projected to be incurred by Tennessee through October
4 31, 2023; the end of the immediately preceding Annual Period. The estimated annual
5 impact of the rate change to Distribution is approximately \$2,000.

a. d. Texas Eastern Transmission, LP.

b. i. PCB Tracker Mechanism

6 On March 18, 1992, FERC approved a settlement creating a PCB Cleanup surcharge
7 mechanism (“PCB Tracker”) under Docket No. RP88-27 (“1992 PCB Settlement”). The
8 PCB Tracker had a 25-year lifetime which expired on March 31, 2017. In early August
9 2017, Texas Eastern filed a Joint Settlement Extension Agreement in Docket Nos. RP17-
10 964 and RP17-967 (“2017 Settlement Extension”). On October 10, 2017, FERC issued a
11 Letter Order approving Texas Eastern’s filing of the Joint Settlement Extension Agreement.
12 The 2017 Settlement Extension addresses the extension of, and certain modifications to,
13 the 1992 PCB Settlement. Significantly, the term of the 1992 PCB Settlement was extended
14 from March 18, 2017 through November 30, 2027.

15 Texas Eastern’s PCB tracker rate during the Historic Period, which was set in
16 Docket No. RP23-100, resulted in approximately \$(1,200) of cost to Distribution. On
15 October 30, 2023, Texas Eastern filed to adjust its PCB Tracker Mechanism rates under
16 Docket No. RP24-82, with an effective date of December 1, 2023. This filing, which was
17 accepted by FERC on November 17, 2023, provides for a reservation rate surcharge of
18 (\$0.003)/Dth, i.e., a decrease of \$4,400 annually.

19 iii. Other Tracker Filings

20
21 On December 30, 2022 and on June 30, 2023, Texas Eastern filed its semi-annual

22 Electric Power Cost Adjustment (“EPCA”) tracker filings under Docket Nos. RP23-330
1 (accepted by FERC January 18, 2023) and RP23-862 (accepted by FERC July 24, 2023),
2 respectively. These filings adjusted the EPCA rate effective February 1, 2023 and August
3 1, 2023, again respectively. The EPCA rate permits Texas Eastern to recover electric
4 compression costs from its customers. Based upon contracted reservation quantities and
5 usage quantities during the Historical Period, Distribution’s EPCA costs were
6 approximately \$37,000.

7 On October 31, 2023, Texas Eastern filed its annual Applicable Shrinkage
8 Adjustment (“ASA”) filing to be effective December 1, 2023 in Docket No. RP24-102.
9 The ASA calculation reflects the retainage percentages required to compensate Texas
10 Eastern for company use gas, including compression, and lost and unaccounted for
11 volumes. The filing was approved on November 20, 2023 and resulted in a 0.03% increase
12 in retainage volumes provided by Distribution when it ships gas on the Texas Eastern
13 system.

14 **iv. General NGA Section 4 Rate Case**

15 On July 30, 2021, Texas Eastern filed a general NGA Section 4 Rate Case in
16 Docket No. RP21-1001 proposing an approximately 53% increase to rates. In the filing,
17 Texas Eastern proposed to utilize a corporate tax rate of 25% under the assumption that
18 Congress will raise the current tax rate (21%) in the near future. The Commission rejected
19 the filing, concluding that the increased tax rate is speculative. The Commission also found
20 that elements of Texas Eastern’s reservation charge failed to comply with Commission
21 policy, and that the tariff changes appeared to be unjust and unreasonable. The
22 Commission ordered Texas Eastern to show cause as to why its tariff concerning
23 reservation charge credits conforms with Commission policy. Texas Eastern made the

1 required filing. On September 30, 2021, Texas Eastern also re-filed a new general NGA
2 Section 4 Rate Case in Docket No. RP21-1188 proposing an approximately 43% increase
3 to rates. Distribution joined a customer group with similarly situated local distribution
4 companies. As part of the customer group, Distribution engaged in a series of settlement
5 negotiations that resulted in a Stipulation & Agreement filed on September 8, 2022. The
6 Commission issued a Letter Order approving the Stipulation and Agreement on November
7 30, 2022. The Commission issued an Order on April 3, 2023 accepting the compliance
8 filing tariff records. On May 12, 2023, Texas Eastern issued a Base Rate Refund Report,
9 which was approved on June 9, 2023.

10 e. Gas-Electric Communications of Operational Information with PJM
11 Interconnection, L.L.C. ("PJM")
12

13 There were no PJM filings during the Historical Period that warranted Distribution's
14 regulatory involvement, however, Distribution and PJM share non-public, operational
15 information for the purpose of promoting reliable service or operational planning pursuant
16 to FERC Orders 787 and 787-A. FERC allows for electric transmission operators to share
17 non-public, operational information with LDCs, subject to various conditions, which are
18 reflected in PJM's tariff.

19 f. National Fuel Gas Distribution Corporation

20 On August 20, 1981, FERC granted Distribution an Order No. 63 Certificate,
21 authorizing Distribution to sell, transport or assign gas to the same extent and in the same
22 manner that intrastate pipelines are authorized to engage in such activities by Subparts (C),
23 (D), and (E) of Part 284 and Section 284.203 of the Commission's regulations. FERC's
24 order granting Distribution's Order No. 63 Certificate expressly provided that, prior to
25 charging a transportation rate for such service, Distribution was required to file for approval

1
2 of a rate methodology pursuant to 18 C.F.R. § 284.224(e)(2). Under current regulations,
3
4 intrastate pipelines operating under 18 C.F.R. § 284.224(e)(2) are required to amend their
5
6 transportation rate every five years; Distribution’s last such filing occurred in February
7
8 2018. Distribution filed to amend its rates in Docket No. PR23-68 on August 31, 2023.
9
10 FERC accepted Distribution’s revised rates, as filed, on October 6, 2023. Finally,
11
12 Distribution submitted four FERC Form 549D – Quarterly Transportation and
13
14 Storage Report of Intrastate Natural Gas and Hinshaw Pipelines filings during the
15
16 Historic Period.¹
17

18 **2. FERC Rulemakings and Generic Federal Proceedings**

19 **a. American Gas Association**

20 Distribution is an active member of the American Gas Association (“AGA”). AGA is
21
22 the national trade association of local gas distribution companies (“LDCs”). AGA acts as an
23
24 advocate for LDCs and their customers before Congress, the FERC, the Commodity Futures
25
26 Trading Commission (“CFTC”) (which regulates certain aspects of energy trading), the Pipeline
27
28 and Hazardous Materials Safety Administration (“PHMSA”), other federal agencies, and the
29
30 courts. Regarding FERC, AGA among other things, participates in FERC rulemakings and other
31
32 proceedings to ensure that LDCs and their customers can obtain necessary services from interstate
33
34 pipelines at rates, terms, and conditions that are just and reasonable. AGA also participates in
35
36 FERC proceedings to support the development of reasonable policies involving gas-electric
37
38 coordination, in order to ensure that the growing use of natural gas for electric power generation
39
40 does not adversely affect service to residential and business/industrial natural gas customers.
41
42 Moreover, AGA participates in PHMSA proceedings to support the development of pipeline safety
43
44 regulations that are designed to improve public safety in a reasonable and cost-effective manner.

45 Through AGA, Distribution has participated in recommending positions to FERC, other
46
47 federal agencies, appellate courts and Congress on issues of importance to Distribution and LDCs

¹ FERC Form No. 549D were filed on February 2, 2023, May 3, 2023, August 3, 2023, and November 2, 2023.

1 as a group. Distribution has found that active participation in AGA is an effective and efficient
2 way to ensure that its position is heard on large generic issues facing LDCs. As a member of AGA,
3 Distribution advocates development of LDC positions consistent with its own stance on such
4 issues.

5 AGA filed several filings at FERC during the historical period. On December 19, 2022,
6 AGA, along with the American Public Gas Association, American Forest & Paper Association,
7 Industrial Energy Consumers of America, Process Gas Consumers Group, and Natural Gas Supply
8 Association submitted a rehearing request in *Revised Filing and Reporting Requirements for*
9 *Interstate Natural Gas Company Rate Schedules and Tariffs*, Docket No. RM21-18-000, requesting
10 FERC to revise Order No. 884 to state that relevant material to be filed in a Natural Gas Act
11 section 4 proceedings in native form is public information, including embedded codes and links.
12 On March 13, 2023 and June 12, 2023, AGA filed an intervention and submitted post-technical
13 conference comments in *Florida Gas Transmission Company, LLC*, Docket No. RP23-466-000,
14 which concerns Florida Gas Transmission Company, LLC's ("FGT") proposal to modify its tariff
15 language to provide standards and establish procedures that will allow for receipt of renewable
16 natural gas ("RNG") on FGT's pipeline system. On June 12, 2023, AGA intervened in *Application*
17 *of Argus Media Inc. for Price Index Developer Re-Approval under the Revised Policy Statement on*
18 *Natural Gas and Electric Price Indices*, Docket No. PL03-3-012. On February 22, 2023, AGA
19 intervened in *Application of S&P Global Commodity Insights for FERC PRA Re-approval for*
20 *Natural Gas Indices*, Docket No. PL03-3-011. On April 26, 2023, AGA filed an intervention in
21 *Columbia Gas of Virginia*, Docket No. CP23-77-000, which concerns an application for a
22 certificate to transport RNG in interstate commerce.

23 AGA also intervened in several FERC dockets of interest to members throughout the
24 historical period. For example, AGA intervened in several dockets related to the certification of
25 facilities. These certificate cases included Docket Nos. Docket No. CP23-30-000 (intervention
26 filed on January 10, 2023), Docket Nos. CP22-21-000 and CP22-22-000 (intervention filed on
27 January 23, 2023), Docket No. CP22-493-000 (intervention filed on February 7, 2023), Docket No.

1 CP23-541-000 (intervention filed on October 3, 2023), and Docket No. CP24-8-000 (intervention
2 filed on November 20, 2023).

3 Regarding other federal agencies, AGA is active in proceedings of interest to members.
4 For example, AGA is active at the CFTC and PHMSA, among others, during the historical period.
5 Specifically, AGA was active on the CFTC's Energy and Environmental Markets Advisory
6 Committee which advises the agency on energy derivative matters.

7 Concerning PHMSA, on August 16, 2023, AGA, along with other trade associations filed
8 joint comments on PHMSA's Notice of Proposed Rulemaking, Pipeline Safety: Gas Pipeline Leak
9 Detection and Repair. The joint comments support the intent of the proposed rule and share
10 PHMSA's goals of addressing methane emissions, but raised certain concerns related to the
11 proposal, such as on matters related to costs and the implementation timeline, among others.

12 AGA also makes submissions in cases before the Supreme Court and the U.S. Court of
13 Appeals. For example, on July 19, 2023, AGA joined several other associations in filing an amicus
14 brief in *Mountain Valley Pipeline, LLC v. Wilderness Society, et al v. Appalachian Voices, et al.*,
15 Docket Nos. 23-1592, 23-1594, & 23-1384 (Sup. Court). The amicus brief supported the request
16 for an emergency relief to prevent unreasonable delays of the Mountain Valley Pipeline that was
17 already approved by Congress. On October 24, 2023, AGA filed an amicus brief in *New Jersey*
18 *Conservation Foundation, et al., v. FERC*, Docket Nos. 23-1064, *et al.* AGA filed the brief in
19 support of the LDCs that contracted for capacity on the pipeline project that received a FERC
20 certificate.

21 On behalf of more than 200 LDCs, AGA provides a level of advocacy that individual
22 LDCs could not possibly achieve on their own. For example, AGA advocates in favor of Low-
23 Income Home Energy Assistance Program ("LIHEAP") funding, which enables low-income gas
24 customers to avoid disconnection of service when they are unable to pay their gas bills.
25 Furthermore, AGA holds numerous conferences, workshops, and webinars to help members keep
26 current on the latest issues facing the industry, along with the newest practices and technologies in
27 various fields, such as operations and engineering, accounting, legal, information technology,

1 finance, customer activities, government relations, and communications. AGA also provides
2 reference materials and standards that help member companies to implement the best and most
3 current operational and business practices.

4 All these services provided by AGA, benefit current natural gas customers by helping
5 AGA member companies to achieve operational, technological, and customer service excellence,
6 and helping those companies enhance the safe delivery of natural gas to consumers.

7 **b. North American Energy Standards Board**
8

9 Distribution is a member of the North American Energy Standards Board
10
11 (“NAESB”) within the Wholesale Gas Quadrant, LDC Segment. NAESB is a broad-based
12
13 standards organization, which addresses standards/model business practices development
14
15 for three industry quadrants: Wholesale Gas, Wholesale Electric, and Retail (addressing
16
17 both gas and electric retail business practices). Distribution’s participation in NAESB
18
19 helps to ensure that the LDC position is recognized in resolving the many issues being
20
21 addressed by this organization. Distribution has closely monitored the ongoing NAESB
22
23 compliance filings made by the upstream pipelines, filing substantive comments as
24
25 warranted.

FERC Filings for which NFG is the Author: Pipeline: COLUMBIA GAS TRANSMISSION
DateRange: 12/01/2022 - 11/30/2023

Docket #	Document Type	Filing Date	Description
RP23-318	MOTION FOR LEAVE TO INTERVENE	12/30/2022	COMPLIANCE FILING: PENALTY REVENUE CREDIT REPORT 2022 TO BE EFFECTIVE N/A
RP23-501	MOTION FOR LEAVE TO INTERVENE	2/28/2023	§4(D) RATE FILING: EPCA 2023 TO BE EFFECTIVE 4/1/2023
RP23-502	MOTION FOR LEAVE TO INTERVENE	2/28/2023	§4(D) RATE FILING: TCRA 2023 TO BE EFFECTIVE 4/1/2023
RP23-503	MOTION FOR LEAVE TO INTERVENE	2/28/2023	§4(D) RATE FILING: RAM 2023 TO BE EFFECTIVE 4/1/2023
RP23-524	MOTION FOR LEAVE TO INTERVENE	3/1/2023	§4(D) RATE FILING: CCRM 2023 TO BE EFFECTIVE 4/1/2023
RP23-662	MOTION FOR LEAVE TO INTERVENE	3/31/2023	§4(D) RATE FILING: OTRA SUMMER 2023 TO BE EFFECTIVE 5/1/2023
RP23-824	MOTION FOR LEAVE TO INTERVENE	6/1/2023	§4(D) RATE FILING: PERIODIC TCRA FILING - TEXAS EASTERN REFUND TO BE EFFECTIVE 7/1/2023
RP24-121	MOTION FOR LEAVE TO INTERVENE	11/1/2023	§4(D) RATE FILING: OTRA WINTER 2023 TO BE EFFECTIVE 12/1/2023

FERC Filings for which NFG is the Author: Pipeline: NFG SUPPLY
DateRange: 12/01/2022 - 11/30/2023

Docket #	Document Type	Filing Date	Description
RP23-441	MOTION FOR LEAVE TO INTERVENE	2/15/2023	COMPLIANCE FILING: FUEL TRACKER FILING GT&C 41 (2023) TO BE EFFECTIVE 4/1/2023
RP23-1097	MOTION FOR LEAVE TO INTERVENE	9/29/2023	\$4(D) RATE FILING: GT&C SECTION 42 GHG/PS FILING 2023 TO BE EFFECTIVE 11/1/2023

FERC Filings for which NFG is the Author: Pipeline: TENNESSEE GAS PIPELINE
DateRange: 12/01/2022 - 11/30/2023

Docket #	Document Type	Filing Date	Description
RP23-210	MOTION FOR LEAVE TO INTERVENE	11/29/2022	COMPLIANCE FILING: CASHOUT REPORT 2021-2022 TO BE EFFECTIVE N/A
RP23-522	MOTION FOR LEAVE TO INTERVENE	3/1/2023	\$4(D) RATE FILING: TGP 2023 FUEL TRACKER FILING DOCKET NO RP23- TO BE EFFECTIVE 4/1/2023
RP23-863	MOTION FOR LEAVE TO INTERVENE	6/30/2023	TARIFF AMENDMENT: AMENDMENT TGP POWERSERVE TO BE EFFECTIVE 10/1/2023
RP23-1103	MOTION FOR LEAVE TO INTERVENE	9/29/2023	\$4(D) RATE FILING: PIPELINE SAFETY AND GREENHOUSE GAS COST ADJUSTMENT MECHANISM - 2023 TO BE EFFECTIVE 11/1/2023

FERC Filings for which NFG is the Author: Pipeline: TEXAS EASTERN TRANSMISSION
DateRange: 12/01/2022 - 11/30/2023

Docket #	Document Type	Filing Date	Description
RP23-330	MOTION FOR LEAVE TO INTERVENE	12/30/2022	§4(D) RATE FILING: TETLP EPC FEB 2023 FILING TO BE EFFECTIVE 2/1/2023
RP23-451	MOTION FOR LEAVE TO INTERVENE	2/21/2023	COMPLIANCE FILING: TETLP FEBRUARY 2023 PENALTY DISBURSEMENT REPORT TO BE EFFECTIVE N/A
RP23-664	MOTION FOR LEAVE TO INTERVENE	3/31/2023	COMPLIANCE FILING: TETLP MARCH 2023 PENALTY DISBURSEMENT REPORT TO BE EFFECTIVE N/A
RP23-862	MOTION FOR LEAVE TO INTERVENE	6/30/2023	§4(D) RATE FILING: TETLP EPC AUG 2023 FILING TO BE EFFECTIVE 8/1/2023
RP23-980	MOTION FOR LEAVE TO INTERVENE	8/25/2023	COMPLIANCE FILING: TETLP AUGUST 2023 PENALTY DISBURSEMENT REPORT TO BE EFFECTIVE N/A
RP24-68	MOTION FOR LEAVE TO INTERVENE	10/27/2023	COMPLIANCE FILING: TETLP OCTOBER 2023 PENALTY DISBURSEMENT REPORT TO BE EFFECTIVE N/A
RP24-82	MOTION FOR LEAVE TO INTERVENE	10/30/2023	§4(D) RATE FILING: TETLP PCB DEC 2023 FILING TO BE EFFECTIVE 12/1/2023
RP24-102	MOTION FOR LEAVE TO INTERVENE	10/31/2023	§4(D) RATE FILING: TETLP ASA DEC 2023 FILING TO BE EFFECTIVE 12/1/2023

FERC Filings for which NFG is the Author - NFGDC FERC Required Filings
DateRange: 12/01/2022 - 11/30/2023

Docket #	Document Type	Filing Date	Description
FORM 549D	REPORT / FORM	2/2/2023	QUARTERLY TRANSPORTATION AND STORAGE REPORT OF INTRASTATE NATURAL GAS AND HINSHAW PIPELINES
FORM 552	REPORT / FORM	5/1/2023	ANNUAL REPORT OF NATURAL GAS TRANSACTIONS
FORM 549D	REPORT / FORM	5/3/2023	QUARTERLY TRANSPORTATION AND STORAGE REPORT OF INTRASTATE NATURAL GAS AND HINSHAW PIPELINES
FORM 549D	REPORT / FORM	8/3/2023	QUARTERLY TRANSPORTATION AND STORAGE REPORT OF INTRASTATE NATURAL GAS AND HINSHAW PIPELINES
FORM 549D	REPORT / FORM	11/2/2023	QUARTERLY TRANSPORTATION AND STORAGE REPORT OF INTRASTATE NATURAL GAS AND HINSHAW PIPELINES

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

53.64 (c) (5) A listing and updating, if necessary, of projections of gas supply and demand provided to the Commission for any purpose - see § 59.67 (relating to formats). In addition, provide an accounting of the difference between reported gas supply available and gas supply deliverable - including storage - from the utility to its customers under various circumstances and time periods.

Page 2 of this Exhibit provides a copy of National Fuel Gas Distribution Corporation's Form-IRP-GAS-1A: Annual Gas Demand Requirements, as filed in the Company's Annual Resource Planning Report (ARPR) for the Pennsylvania Division, pursuant to 52 Pa. Code §59.81-84.

Form-IRP-GAS-1A: Annual Gas Demand Requirements
Reporting Utility: National Fuel Gas Distribution Corporation - Pennsylvania Division
(Volumes in MMcf)

	Historical Data		Current Year	Three Year Forecast		
Index Year: Actual Year:	-2 2021	-1 2022	0 2023	1 2024	2 2025	3 2026
Firm Sales:						
Retail Residential	16,297	18,089	18,035	18,279	18,398	18,596
Retail Commercial	2,952	3,370	2,964	2,987	2,990	3,005
Retail Industrial	252	347	238	240	239	240
Electric power generation	0	0	0	0	0	0
Exchange with other utilities	0	0	0	0	0	0
Unaccounted for Gas	(67)	(209)	32	33	33	33
Company Use	7	8	15	15	15	15
Other (Off-system)	0	0				
Subtotal Firm Sales	19,441	21,605	21,285	21,553	21,674	21,889
Interruptible Sales:						
Retail	0	0	0	0	0	0
Electric power generation	0	0	0	0	0	0
Company's Own Plant	0	0	0	0	0	0
Subtotal Interruptible	0	0	0	0	0	0
Subtotal Firm and Interruptible Sales:	19,441	21,605	21,285	21,553	21,674	21,889
Transportation:						
Firm Residential	1,956	2,004	1,935	1,881	1,813	1,751
Firm Commercial	6,342	6,596	6,932	7,010	7,061	7,149
Firm Industrial	17,812	16,903	18,728	19,699	20,116	20,291
Interruptible Residential	0	0	0	0	0	0
Interruptible Commercial	0	0	0	0	0	0
Interruptible Industrial	0	0	0	0	0	0
Electric power generation	0	0	0	0	0	0
Subtotal Transportation	26,110	25,502	27,594	28,590	28,990	29,191
Total Gas Requirements	45,551	47,107	48,878	50,143	50,664	51,080
Increase (Decrease)		1,556	1,771	1,265	521	415
Percent Change (%)		3.4%	3.8%	2.6%	1.0%	0.8%

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

- 53.64 (c) (5) A listing and updating, if necessary, of projections of gas supply and demand provided to the Commission for any purpose – see § 59.67 (relating to formats). In addition, provide an accounting of the difference between reported gas supply available and gas supply deliverable – including storage – from the utility to its customers under various circumstances and time periods.**

Attached hereto as pages 2 – 5 are copies of National Fuel Gas Distribution Corporation's (a) Form-IRP-Gas-2A Natural Gas Supply – Annual Supply in accordance with PUC Docket No. L-920066: Integrated Resource Planning for Gas Utilities pursuant to 52 Pa. Code § 59.81 – 84 as filed in June 2023;(b) Form-IRP-Gas-2A Natural Gas Supply - Peak Day Supply; (c) Form-IRP-Gas-2B Natural Gas Transportation; (d) Form-IRP-Gas-2C Natural Gas Storage.

Form-IRP-GAS-2A: Natural Gas Supply
Reporting Utility: National Fuel Gas Distribution Corporation - Pennsylvania Division
(Volumes in MMcf)

Index Year Actual Year	Historical Data		Current Year	Three Year Forecast		
	-2 2021	-1 2022	0 2023	1 2024	2 2025	3 2026
Gas Supply for Sales Service Supply contracts (List); ¹						
10513	3,798	6,858	2,224			
309	861	919	1,718			
1012022	-	1,572	1,216			
11	163	72	1,288			
10509	1,836	910	983			
Supply contracts (Other)	2,400	2,908	13,753	21,451	21,572	21,787
Spot Purchases	9,387	8,315				
Storage withdrawals	6,899	7,020	7,100	6,710	6,959	6,661
LNG/SNG/Propane Purchases						
Company Production						
Local Purchases	1,381	-	102	102	102	102
Other						
Total Gas Supply for Sales	26,725	28,574	28,384	28,263	28,633	28,550
Total Transportation Service	26,110	25,502	27,594	28,590	28,990	29,191
Total Sales Gas Supply and Transportation Service						
Deductions						
Curtailments						
Underground Storage Injections	7,284	6,969	7,100	6,710	6,959	6,661
LNG Liquefaction						
Sales to other LDC's						
Off-System Sales						
Total Deductions	7,284	6,969	7,100	6,710	6,959	6,661
Net Gas Supply	45,551	47,107	48,878	50,143	50,664	51,080

¹ Rank contracts in order of magnitude for the current year. Reporting should proceed along rank ordering until 75% of total contract supplies is accounted for, or until ten contracts have been listed, whichever occurs first. (Note: rank ordered based on MDQ).

Form-IRP-GAS-2A: Natural Gas Supply
Table 2: Peak Day Supply
Reporting Utility: National Fuel Gas Distribution Corporation - Pennsylvania Division
(Volumes in MMcf)

PGC Exhibit No. 7-B
Page 3 of 5

	Historical Data		Current Year	Three Year Forecast		
Index Year Actual Year	-2 <u>2021</u>	-1 <u>2022</u>	0 <u>2023</u>	1 <u>2024</u>	2 <u>2025</u>	3 <u>2026</u>
Gas Supply for Sales Service Supply contracts (List); ¹						
10513	3.9	30.6	25.9			
309	9.1	15.5	20.0			
1012022	-	-	16.4			
11	1.7	-	15.0			
10509	13.2	10.7	8.0			
Supply contracts (Other)	47.0	52.1	20.9	106.5	107.1	107.5
Spot Purchases						
Storage withdrawals	80.6	60.9	154.4	158.2	158.6	160.7
LNG/SNG/Propane Purchases						
Company Production						
Local Purchases	8.4	0.3	0.5	0.5	0.5	0.5
Other						
Total Gas Supply for Sales	163.9	170.1	261.1	265.2	266.2	268.7
Total Transportation Service	117.9	150.2	188.1	189.3	189.2	190.2
Total Sales Gas Supply and Transportation Service						
Deductions						
Curtailments						
Underground Storage Injections						
LNG Liquefaction						
Sales to other LDC's	-	-	-	-	-	-
Off-System Sales						
Total Deductions	-	-	-	-	-	-
Net Gas Supply	281.8	320.3	449.2	454.6	455.4	458.9

¹ Rank contracts in order of magnitude for the current year. Reporting should proceed along rank ordering until 75% of total contract supplies is accounted for, or until ten contracts have been listed, whichever occurs first. Provide a separate sheet identifying the supplier for each contract listed. (Note: rank ordered based on MDQ).

Reporting Utility: National Fuel Gas Distribution Corporation - Pennsylvania Division
(Volumes in MMcf)

1 Rank contracts in order of magnitude for the current year. Reporting should proceed along rank ordering until 75% of total contract supplies is accounted for, or until ten contracts have been listed, whichever occurs first. Provide a separate sheet identifying the supplier for each contract listed. (Note: rank ordered based on annual).

2 Storage should net to zero (Net withdrawal activity on Sheet 2-C)

Form-IRP-GAS-2C: Natural Gas Storage
Reporting Utility: National Fuel Gas Distribution Corporation - Pennsylvania Division
(Volumes in MMcf)

Index Year Actual Year	Historical Data				Current Year		Three Year Forecast					
	-2 <u>2021</u>		-1 <u>2022</u>		0 <u>2023</u>		1 <u>2024</u>		2 <u>2025</u>		3 <u>2026</u>	
	<u>Annual</u>	<u>Peak</u>	<u>Annual</u>	<u>Peak</u>	<u>Annual</u>	<u>Peak</u>	<u>Annual</u>	<u>Peak</u>	<u>Annual</u>	<u>Peak</u>	<u>Annual</u>	<u>Peak</u>
Storage Contracts (List); ¹												
1. NFGSC (ESS 1)	5,973.8	54.0	6,063.0	21.1	5,734.4	113.2	5,612.9	117.0	5,859.9	117.4	5,561.2	119.5
2. NFGSC (FSS)	153.9	9.5	212.3	9.5	187.4	10.2	152.7	10.2	148.9	10.2	148.9	10.2
3. NFGSC (FSS 2)	292.4	12.4	200.2	13.4	530.9	13.4	460.4	13.4	466.1	13.4	466.1	13.4
4. Columbia (FSS)	405.1	4.7	478.9	16.9	647.3	17.6	484.4	17.6	484.4	17.6	484.4	17.6
Other	-	-	-	-	-	-	-	-	-	-	-	-
Total	6,825.2	80.6	6,954.5	60.9	7,100.0	154.4	6,710.4	158.2	6,959.3	158.6	6,660.6	160.7

¹ Rank contracts in order of magnitude for the current year. Reporting should proceed along rank ordering until 75% of total contract supplies is accounted for, or until ten contracts have been listed, whichever occurs first. Provide a separate sheet identifying the supplier for each contract listed. (Note: rank ordered based on MDQ).

NATIONAL FUEL GAS DISTRIBUTION CORPORATION**Response of National Fuel Gas Distribution Corporation to the Commission's
Filing Requirement Codified at 52 Pa. Code §53.64(c)(6) --**

Each Section 1307(f) utility shall file with the Commission a statement of its current fuel procurement practices, detailed information concerning the staffing and expertise of its fuel procurement personnel, a discussion of its methodology for obtaining a least cost and reliable source of gas supply, including a discussion of any methodologies, assumptions, models or rules of thumb employed in selecting its gas supply, transportation and storage mix, its loss prevention strategy in the event of fraud, nonperformance or interruption of performance, its participation in capacity release and reallocation programs, the impact, if any, upon least cost fuel procurement by constraints imposed by local transportation end users, interruptible service, balancing, storage and dispatching options, and its strategy for improving its fuel procurement practices in the future and timetable for implementing these changes.

CONTENTS**I. CAPACITY RESERVED FOR DISTRIBUTION'S CUSTOMERS**

- A. Reservation of Capacity - Generally
- B. Winter 2023-2024 Pipeline and Storage
- C. Release of Capacity to SATS Suppliers
- D. Retained Capacity for Temperature Variability and Peaking

II. DISTRIBUTION'S LEAST COST PURCHASE STRATEGY

- A. General
- B. Pipeline Costs
- C. Ongoing Review of Capacity Contracts to Reduce Costs
- D. Storage Utilization Strategy
- E. Future Capacity and Procurement Plans
- F. No Cost Gas Exchange Agreements and Other Utility Purchases
- G. Gas Supply Mix

III. CREDITS FOR CAPACITY RELEASE, OFF-SYSTEM SALES AND STORAGE FILL AGREEMENTS

- A. General Capacity Release and Off-System Sales Procedures
- B. Capacity Releases
- C. Off-system Sales
- D. Storage Fill Agreements
- E. Asset Management Arrangements

IV. STAFFING AND EXPERTISE OF FUEL PROCUREMENT PERSONNEL

1
2 This statement of gas purchase practices and strategy provides a
3 summary of the procedures for obtaining gas supplies during the historic
4 reconciliation period (the 12 months ended November 30, 2023), the procedures to
5 be used during the period December 1, 2023 through July 31, 2024 and expected to
6 be used during the period August 1, 2024 through July 31, 2025. The last
7 referenced period (August 1, 2024 through July 31, 2025) is the Application Period
8 during which, subject to quarterly adjustments, recovery rates set in this proceeding
9 will be in effect.

10 **I. CAPACITY RESERVED FOR DISTRIBUTION'S CUSTOMERS**

11 **A. Reservation of Capacity - Generally**

12 Distribution has entered into contracts for transportation and storage
13 capacity on National Fuel Gas Supply Corporation ("Supply") and on upstream
14 interstate pipelines to meet the requirements of its firm sales customers.

15 Distribution's system consists of numerous small, geographically
16 dispersed distribution systems serving local markets, many of which are not
17 interconnected by Distribution's own facilities. Instead, Supply's substantial
18 transmission system interconnects these distribution systems, providing the vital
19 interconnections between Distribution's dispersed market areas and the upstream
20 pipelines. See PGC Exhibit No. 8-A for a map of Supply's system. Supply's
21 transmission facilities also interconnect Supply's extensive storage facilities and
22 Distribution's various local distribution systems.

23 As described above, several of Distribution's market areas are not

1 interconnected with other market areas of Distribution. They are supplied by
2 upstream pipeline, transportation and storage capacity contracted with Supply,
3 Columbia Gas Transmission LLC (“Columbia”), Tennessee Gas Pipeline
4 Company, L.L.C. (“Tennessee” or “TGP”) and Texas Eastern Transmission, LP
5 (“Texas Eastern” or “TETCO”). All of Distribution’s pipeline and storage capacity
6 is critical capacity. This mix of capacity meets Distribution’s unique market
7 reliability requirements at the least cost to the customer. The capacity plays a
8 critical role in directly serving customer requirements including filling
9 Distribution’s contracted storage capacity with Supply.

10 Distribution's contracts with Tennessee contain grandfathered
11 redundant delivery rights and “virtual” nomination points that allow Distribution to
12 direct its gas supplies to various market delivery points as needed to serve customer
13 requirements during the winter and to fill storage during the summer.
14 Distribution’s redundant delivery point flexibility is available to replacement
15 suppliers receiving released Tennessee FT-A rate schedule capacity from
16 Distribution. The Tennessee capacity is also required to provide the Company the
17 ability to fill certain storage capacity on Supply that can only be filled using
18 Tennessee’s Zone 4 capacity, and to meet the obligations under Supply’s EFT tariff
19 provisions that require Distribution to deliver gas supplies to Supply receipt meters
20 at the volumes and pressures necessary to satisfy Distribution’s market conditions.
21 Distribution's transportation and storage contracts with Columbia provide delivery
22 capability to serve the requirements of discrete markets and of the system in

1 general. Because the pipeline transportation and storage capacities that are
2 maintained with Supply, Columbia, Tennessee and Texas Eastern are critical to
3 system operations, these contracts cannot be replaced by substitute natural gas
4 suppliers.

5 Distribution uses its pipeline transportation and storage capacity
6 year-round to serve its firm market requirements on a reliable basis. Generally,
7 during the winter season Distribution meets its sales requirements by purchasing
8 gas and withdrawing gas from storage and transporting it via upstream and Supply
9 pipelines to Distribution's system. In the summer, Distribution uses upstream
10 capacity that is not needed to serve market requirements, to inject gas into storage,
11 to be withdrawn in the winter.

12 **B. Winter 2023-2024 Pipeline and Storage**

13 Distribution has reserved firm transportation, storage and winter gas
14 supply capacity as shown in PGC Exhibit No. 4-A to meet its forecasted design day
15 market requirements for the winter 2023 – 2024.

16 **C. Release of Capacity to SATS Suppliers**

17 Distribution has reserved upstream pipeline and storage capacity to meet its
18 obligations to its Sales and Small Aggregation Transportation Customer ("SATC")
19 service customers. Pursuant to its tariff, Distribution releases a quantity of its
20 Supply EFT and ESS capacity and its Tennessee FT-A Z4 to Z4 capacity to Small
21 Aggregation Transportation Supplier ("SATS") service suppliers that serve
22 Distribution's SATC customers. This released capacity is sufficient for SATS

1 suppliers to comply with Distribution's daily delivery quantity requirement for
2 serving the SATC customer heating requirements up to 62 degree days (DD).
3 Under the current Customer Choice Program, SATS suppliers are assigned
4 (through capacity release) the assets they need to provide service to their SATC
5 customers, other than the retained capacity.

6 **D. Retained Capacity for Temperature Variability and Peaking**

7 Distribution retains capacity to meet the temperature variability and peaking
8 requirements of its combined sales and SATC customers. This capacity will be
9 used to serve temperature swing load which results from the variance between the
10 predicted and actual weather and associated customers' usage per DD. This
11 capacity will be retained and managed by Distribution to provide deliverability to
12 its sales and SATC customers on peak days. This capacity is designed to serve a
13 combined sales and SATC customer load equivalent to 12 DD, or when the gas
14 day's mean temperature varies from +2°F down to -9°F. The SATC customers,
15 therefore, need only be assigned capacity to serve their requirements equivalent to
16 62 HDD, or when the mean temperature of the gas day is 3°F and above. See PGC
17 Exhibit No. 8-D for the retained capacity calculation as of August 1, 2024.

18 **II. DISTRIBUTION'S LEAST COST PURCHASE STRATEGY**

19 **A. General**

20 Distribution continually reviews its mix of pipeline and storage
21 capacity to provide the critical link between Distribution and the primary sources of
22 its gas supply. Distribution uses this capacity to source the lowest cost gas supplies

1 that are consistent with maintaining adequate, reliable and reasonably continuous
2 service.

3 Distribution reviews its capacity portfolio annually to address its
4 market requirements based on annual market forecast updates. Distribution
5 evaluates its mix of capacity, focusing on its capacity costs, diversity and the
6 reliability of its gas supplies. Specifically, the primary objectives of Distribution's
7 capacity mix and least-cost gas procurement strategies can be summarized as
8 follows:

9 (1) Reservation of capacity needed (both transportation
10 and storage) to obtain gas supplies at the lowest possible cost while
11 assuring reliability and maintaining operational integrity.

12 (2) Maintenance of adequate and reliable supplies,
13 purchased under a variety of gas supply arrangements, appropriately
14 structured to meet the near and mid-term daily, winter season, peak
15 day and annual requirements of Distribution on a least-cost basis;
16 and

17 (3) Manage gas costs by the dispatching of gas to ensure
18 adequate supply coverage and maximization of lowest cost supplies,
19 within the constraints imposed by contract provisions and system
20 capacity considerations.

21 **B. Pipeline Costs**

1 Distribution actively participates in proceedings at the Federal
2 Energy Regulatory Commission (“FERC”), defending its interests as a local
3 distribution company in cases where such action is appropriate.

4 The most significant proceedings and Distribution’s involvement are
5 identified in PGC Exhibit No. 6.

6 **C. Ongoing Review of Capacity Contracts to Reduce Costs**

7 Distribution has contracted for transportation and storage capacity to
8 meet the design day and seasonal needs of its customers. See PGC Exhibit No. 8-
9 B, the load duration curve for the 2024-2025 design day and the demand load for
10 Distribution’s 15% colder than normal (ctn) forecast. Distribution continues to
11 review its mix of capacity, in an effort to enhance reliability and reduce costs,
12 particularly in situations where there are options to renew or cancel contracts. It is
13 important to note that Distribution does not simply contract for new capacity each
14 year. Distribution is limited by its existing portfolio of contracts such that
15 opportunities to adjust contracts do not always line up with changes in
16 Distribution’s updated forecasts of its requirements. Further, the requirements for
17 the system change on a year-to-year basis, going up or down as the customer load
18 shifts.

19 **D. Storage Utilization Strategy**

20 Distribution uses its storage capacity primarily to ensure reliability
21 of system delivery. Based on normal temperatures during the 2023-2024 winter, it
22 is projected that approximately 40% of winter supplies and 65% of design day

1 supplies will be sourced from storage. Storage is also used to enhance purchasing
2 capabilities by facilitating the purchase of gas at higher year-round load factors due
3 to the ability to inject gas into storage during the summer months when customer
4 demand is lower. If Distribution did not have its current level of storage, it would
5 have to obtain additional upstream transportation capacity and pay year-round
6 demand charges for use only in the winter period. This would decrease the year-
7 round load factor that could result in a substantial cost increase to its customers.

8 Furthermore, storage enables Distribution to purchase gas during the
9 summer, when prices are historically lower and less volatile, and inject this gas into
10 storage, to be withdrawn from storage in the winter when prices are historically
11 higher and more volatile. PGC Exhibit No. 8-C, depicts Distribution's daily send
12 out for the twelve months ending September 30, 2023, that clearly shows the role
13 of storage in meeting Distribution's market needs. The graph illustrates
14 withdrawals from storage when "demand" exceeds "flowing gas supplies" and an
15 injection into storage when "flowing gas supplies" are greater than "demand".

16 In addition, the availability of storage and the consequent increase in
17 load factor on the upstream pipelines has reduced Distribution's need to rely on
18 peak day pipeline capacity or other peak shaving facilities typically relied upon by
19 other LDCs, e.g., propane and liquefied natural gas.

20 **E. Future Capacity and Procurement Plans**

21 Subject to its critical capacity requirements described above,
22 Distribution will continue to evaluate opportunities to adjust its portfolio of capacity to

1 enhance reliability and achieve savings for its customers. As previously discussed,
2 Distribution reviews its capacity portfolio annually to address its forecasted market
3 requirements. Distribution prepares annual 5 year market forecasts. The most recent
4 two consecutive 5 year market forecasts reflect demand growth that suggest additional
5 capacity for the winter 2024-2025 is necessary. Further discussion will be included in
6 Ms. Petko's direct testimony, and Exhibit LAP-4, which reviews the winter capacity
7 analysis.

8 Distribution anticipates that it will renew its current pipeline and
9 storage contracts per the notice dates as explained in PGC 4-A. Significant
10 changes to contracts are described below:

11 **(BEGIN CONFIDENTIAL PORTION)**

12

13

(END CONFIDENTIAL PORTION)

F. No Cost Gas Exchange Agreements and Other Utility Purchases

Details of these Agreements and LDC tariff sales service purchases are provided in PGC Exhibit No. 4. Distribution does not expect to modify or add to the No Cost Exchange Agreements through the end of the Application Period. Distribution is currently coordinating with Peoples Natural Gas Company, LLC for the construction of a new third interconnection facility to replace existing Distribution facilities serving its customers in the region. The new interconnection's planned in-service date is scheduled for completion during Winter 2023/2024.

H. Gas Supply Mix

(1) Mitigation of Commodity Price Volatility

Distribution purchases gas pursuant to its Gas Cost Management Plan ("Plan") to reduce the effects of gas price volatility on sales customers. The Plan has continued to evolve as Distribution has gained experience under its Plan and responded to the changes in the marketplace. The overall goal of the Plan however, to mitigate price volatility through price diversification, has not changed.

The Plan diversifies pricing by requiring that for a normal winter season of November through March, approximately 40% of winter gas supplies

1 will be withdrawn from storage at prices determined during the summer injection
2 season, 12% will be forward priced during the summer, 24% will be monthly
3 priced and 24% will be daily priced. Storage and forward priced supplies enable
4 Distribution to achieve price certainty for approximately 52% of its required gas
5 supplies.

6 Similar to last year, each winter's forward prices are established by
7 entering into four winter physical supply transactions which specify the pricing of
8 quantities to be delivered during the winter months. These quantities are
9 purchased as a fixed price and/or an index price not to exceed an agreed upon price
10 cap. Under the Plan for the 2023-2024 winter season, on predetermined days during
11 the NYMEX trading period from April 2023 through October 2023, Distribution
12 fixed the contract price for a pro rata share of the gas that it would purchase under
13 the Plan for delivery during the period November 1, 2023 through March 31, 2024.
14 A copy of the currently executed Plan is provided as PGC No. 8-E but will be
15 revised.

16 Per Docket Nos. R-2023-3037428, the Company has revised the
17 current Plan and has incorporated fixed priced purchases in its summer gas
18 purchase portfolio. For deliveries beginning April 1st, 2025, the Plan is revised to
19 include 15-20% of forecasted requirements will be purchased at a fixed price
20 during the summer prior to delivery, 30-35% will be monthly priced and 50% will
21 be daily priced. A copy of the revised Plan is provided as PGC No. 8-F.

22

(2) Term Purchase Supplies

Distribution secures firm gas supplies on a Term (delivery period greater than one month) basis when and where it concludes that it is necessary to ensure reliable deliveries. For the period December 1, 2022 to November 30, 2023, Distribution purchased Term supplies of approximately 7,800,000 Dth or 39% of total supplies. Commodity prices are usually determined monthly or daily based upon published price indices, NYMEX settle price, or negotiated rates (i.e., cash). The monthly gas is a blend of negotiated rate (cash) priced, monthly index priced and NYMEX priced transactions.

Pursuant to Distribution's Master Gas Purchase Contracts and North American Energy Standards Board ("NAESB") Contracts, suppliers dedicate quantities of gas to Distribution for typically seasonal terms. These contracts have strong liquidated damages language to encourage suppliers to deliver the contracted volumes. Distribution may pay a small premium for firm dedication of Term supplies. The small premiums paid represent the price of the supply security afforded under the Term contracts. Distribution's procedures for entering into firm contracts and efforts to minimize premiums for Term supplies are more fully described in PGC Exhibit No. 4.

The portfolio of Term purchases that includes a mix of baseload supplies and flexible delivery supplies is formulated around Distribution's firm upstream pipeline and storage capacity and extensive storage capacity on Supply's system. The Term purchase agreements with delivery flexibility reserve

1 Distribution the right to take delivery from the supplier or release that delivery right
2 back to the supplier, who then may sell the gas to another party, commonly referred
3 to as take or release.

4 **(3) Spot Purchase Supplies**

5 Distribution has historically sought and obtained volumes of gas on
6 a Spot (delivery period equal to, or less than, one month) basis to supplement Term
7 purchases on pipelines where gas supplies were abundant and, therefore, where it
8 was not necessary to pay a premium for such gas in order to assure delivery. With
9 the continued growth of Northeast Shale gas, sourcing of such gas supplies has
10 shifted from the traditional sources in the Southwest and Canada to the Northeast
11 Shale region.

12 Through the methodology described in PGC Exhibit No. 4,
13 Distribution will continue to purchase lower cost market area quantities on a firm
14 Spot delivery basis.

15 For the period December 1, 2022 to November 30, 2023,
16 Distribution's summer and winter Spot gas purchases accounted for approximately
17 12,5000 Dth of Spot gas or 61% of total supplies.

18 **(4) Non-Firm Local Production and Appalachian Supply**

19 Distribution's purchases during the historic period are reported in
20 PGC Exhibit No. 4. Distribution expects to continue to purchase non-firm,
21 dedicated and excess local production gas for the near-term into its system and

1 Supply's system at prices that do not increase the weighted average commodity
2 cost of gas supplies sold to its customers.

3 **(5) Tariff Purchase Supplies**

4 Distribution's purchases pursuant to its tariff during the historic
5 period are reported in PGC Exhibit No. 4. Distribution is not able to predict
6 whether or not such purchases will be required in the future.

7 **(6) General Supply Approach**

8 Firm transportation contracts and Term gas purchase contracts
9 assure security of supply and deliverability. Notwithstanding this fact, Distribution
10 has also purchased Spot gas at market prices instead of contracting for Term
11 supplies to the extent that reliability of such supply was not an issue. Distribution
12 makes the decision to select Spot purchases to the extent such supplies are needed
13 on a monthly and/or daily basis, comparing all alternative sources of gas and
14 selecting the least cost supplies from those offered.

15 For the 2022-2023 winter, Distribution has utilized Term contracts
16 to obtain firm commitments for delivery from its suppliers. The projected normal
17 weather core requirements are expected to be served by the following: 40% storage
18 withdrawals; 24% market-based monthly-priced gas; 24% market-based daily-
19 priced gas and 12% forward fix priced gas.

20 These purchasing plans have produced a well-balanced gas contract
21 portfolio that provides the mitigation of pricing risk through diversification of
22 contract terms and pricing provisions. The predetermined price of storage and

1 Forward priced deliveries, representing approximately 52% of winter supplies. The
2 monthly and daily priced gas under the Term contracts, some of which back up
3 replacement monthly and daily Spot purchases, assure that a portion of the supplies
4 are priced at current market without the risk of lowering reliability. Again, this
5 type of gas supply mix diversification allows customers to continue to receive
6 service at a high level of reliability under a least cost purchase plan with reduced
7 exposure to price increases resulting from extreme weather.

8 **III. CREDITS FOR CAPACITY RELEASE, OFF-SYSTEM SALES, AND**
9 **STORAGE FILL AGREEMENTS**

10 **A. General Capacity Release and Off-System Sales Procedures**

11 The first step in determining whether capacity can be released, or an
12 off-system sale can be made, is to determine whether there are gas supplies and/or
13 capacity that will not be needed to meet the requirements of customers. This
14 determination requires consideration not only of projected requirements of
15 Distribution's customers, but also of the need, at various times of the year, to fill
16 storage fields in order to meet peak and winter requirements of customers.

17 While Distribution reviews its requirements and available capacity
18 continually, a review is conducted prior to the commencement of each calendar
19 month to determine, in the aggregate, whether Distribution has firm gas supplies
20 under contract that will not be purchased during the month. If so, Distribution will
21 seek to release capacity that it will not use during the next 30-day period or less.
22 Distribution's process for making such releases available is as follows.
23 Distribution sends an e-mail or instant message to potential customers notifying

1 them of available capacity to be released. Interested customers may contact
2 Distribution to place a bid. Distribution generates capacity release offers and posts
3 all release offers for bidding on the pipeline's electronic bulletin board. Biddable
4 offers may be posted with an interested customer as the pre-arranged bidder,
5 providing an opportunity for the pre-arranged bidder to match a higher bid from
6 any competing bidder.

7 When engaged in off-system sales, Distribution may sell gas at any
8 point on its transportation and storage capacity upstream of its capacity on Supply.

9 It is noted that the demand for and value of capacity release and
10 sales opportunities will vary by time of year and by weather conditions. It can be
11 expected that there will be greater demand for gas supplies and capacity, along with
12 greater margins and release credits, during winter periods, particularly when
13 weather is colder than normal.

14 **B. Capacity Releases**

15 Distribution retains the necessary capacity on upstream pipelines
16 and storages to provide service to its sales customers. Distribution also has
17 capacity to meet the difference between transportation customers' deliveries and
18 takes on the design day.

19 During periods when Distribution is not using all of its capacity to
20 serve its customers, Distribution generally markets its unutilized capacity to other
21 parties as discussed earlier.

Sharable revenues from releases of capacity are allocated 75% to ratepayers and 25% to Distribution. The total value of all sharable releases for the period ending November 30, 2023 was approximately \$1,800,000.

C. Off-System Sales

As approved under previous settlements of Distribution's 1307(f) proceedings, Distribution retains 25% of the net revenues from off-system sales, (before taxes) over the monthly average commodity cost of gas plus any variable transportation costs to deliver the gas to the off-system customer. The monthly average commodity cost of gas is defined as the monthly average commodity cost of gas purchases for all supplies scheduled at the beginning of the month. This method of using the monthly average commodity cost continues to be the appropriate methodology. These contracts have a wide variety of price and flexibility provisions which govern how Distribution purchases gas during a given period. Distribution has set up its least-cost procurement program to include a mix of both base-load and flexible contracts necessary to meet its system requirements. Distribution plans its Term and Spot gas purchases on a monthly basis from its mix of Master Gas Purchase Contracts, NAESB contracts or GISB contracts. The pricing terms for the commodity cost of these gas supplies include but are not limited to: first of month and daily index prices, NYMEX settlement prices and prices fixed in advance of the month of flow. Therefore, the weighted average commodity cost of gas, plus the variable transportation cost to the point of the off-system sale, is the appropriate basis for purposes of determining margin available

1 for sharing. Off-system sales that rely on system supply and whose margins are
2 derived from Distribution's weighted average commodity cost are referred to as
3 "WACC Sales".

4 If an additional, unscheduled purchase is made during the month
5 specifically for an off-system sale, such purchase is considered to be the gas used to
6 make the off-system sale, and the commodity cost of such purchase will be
7 assigned to the off-system sale up to the volume of the purchase. Such purchase
8 may either be transported directly to the sale point via idle but unreleased
9 transportation capacity or via displacement of system supply scheduled for delivery
10 to Distribution's Supply capacity. Under a displacement scenario, the additional
11 unscheduled purchase is delivered to Distribution's Supply capacity in a quantity
12 equal to the originally scheduled system supply delivery that was displaced to make
13 the sale. Annual off-system sale revenues have declined in recent years as
14 Distribution reduces capacity path lengths and places more emphasis on capacity
15 release transactions to optimize the value of its upstream capacity. No off-system
16 sales margins were generated during the 12 month historic period ending
17 November 30, 2022.

18 **D. Storage Fill Agreements**

19 Distribution allocates storage fill credits received under storage fill
20 agreements such that the ratepayers receive 75% and Distribution the remaining
21 25%.

1 In response to a request for proposal issued in March 2022,
2 Distribution entered into a storage fill agreement for the 2023 injection season.
3 The Supplier was required to deliver a portion of a seasonal injection requirement
4 associated with a specific city gate delivery point. In exchange for a discount
5 relative to what Distribution would have otherwise payed, the supplier was
6 provided the ability to choose the days of delivery. In general, Distribution would
7 attempt to purchase injection quantities evenly over the summer injection season in
8 order to diversify inventory gas costs. The total value of the discount was
9 approximately \$130,000.

10 **E. Asset Management Arrangements**

11 In light of the issuance of FERC Order No. 712 and its progeny, in
12 which the FERC clarified and encouraged the use of Asset Management
13 Arrangements (“AMA”), Distribution solicited an AMA proposal from
14 counterparties. The AMA proposal request was structured around filling
15 Distribution storage during the summer, requiring the asset manager to deliver
16 least-cost gas supplies to Distribution at the city gate and Distribution to release a
17 portion of its Tennessee capacity to the asset manager for the summer period.
18 Relative to comparable capacity release values of the asset, offers for an AMA
19 structured around the asset did not yield additional value. Distribution elected not
20 to execute an AMA agreement and instead optimized the pipeline capacity in the
21 off-system sales and capacity release markets.

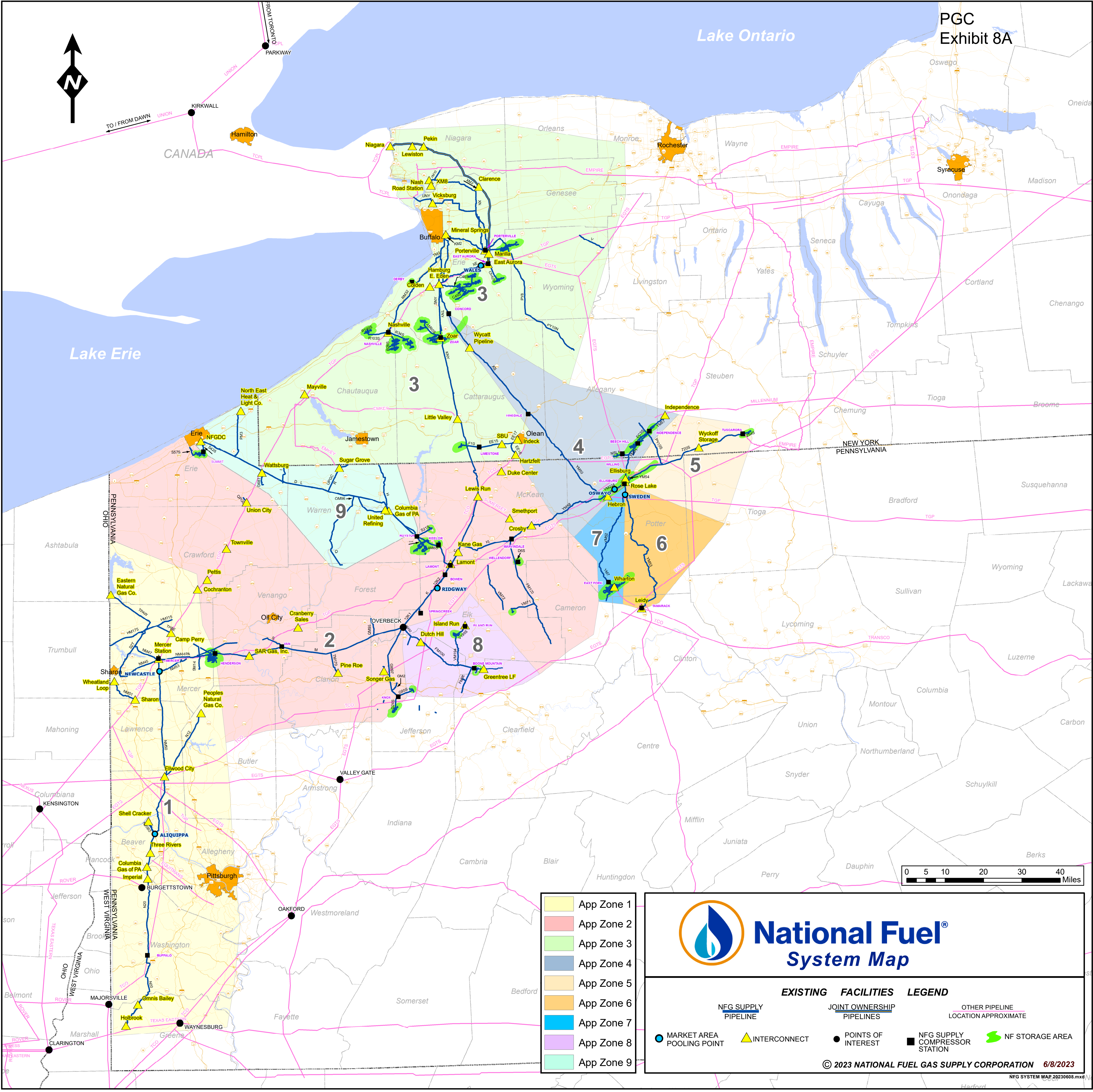
**IV. STAFFING AND EXPERTISE OF FUEL PROCUREMENT
PERSONNEL**

Distribution operates its gas planning, gas accounting, gas procurement & optimization and transportation functions through its Gas Supply Administration (“GSA”) Department from offices located in Williamsville, New York.

As detailed in PGC Exhibit No. 8-G, GSA utilizes functional teams that handle the duties and responsibilities of all the areas that encompass the department. Distribution’s GSA Department is currently fully staffed with 14 employees.

The specific operational and transactional duties that are performed by GSA employees include the following: projecting and monitoring Distribution’s market forecasts and gas supply needs; negotiating and contracting for all pipeline capacity, storage capacity and gas supplies as well as administering those gas supply contracts; accounting for and paying all charges associated with all gas supply contracts and all transportation contracts; daily nominations and monitoring of scheduled volumes; optimization of unutilized pipeline capacity through capacity release or off-system sales; and facilitating customer choice transportation and system operator functions that include verifying, confirming, and tracking capacity upstream and downstream of Distribution interconnects used by marketers and transporters, nominating and tracking retained and released capacity for aggregation services, forecasting and planning for transportation activity, managing and tracking Distribution local production and marketer pooling

- 1 activities and on-system deliveries, coordinating marketer operational meetings,
- 2 and addressing other supplier-of-last-resort issues.



- App Zone 1
- App Zone 2
- App Zone 3
- App Zone 4
- App Zone 5
- App Zone 6
- App Zone 7
- App Zone 8
- App Zone 9



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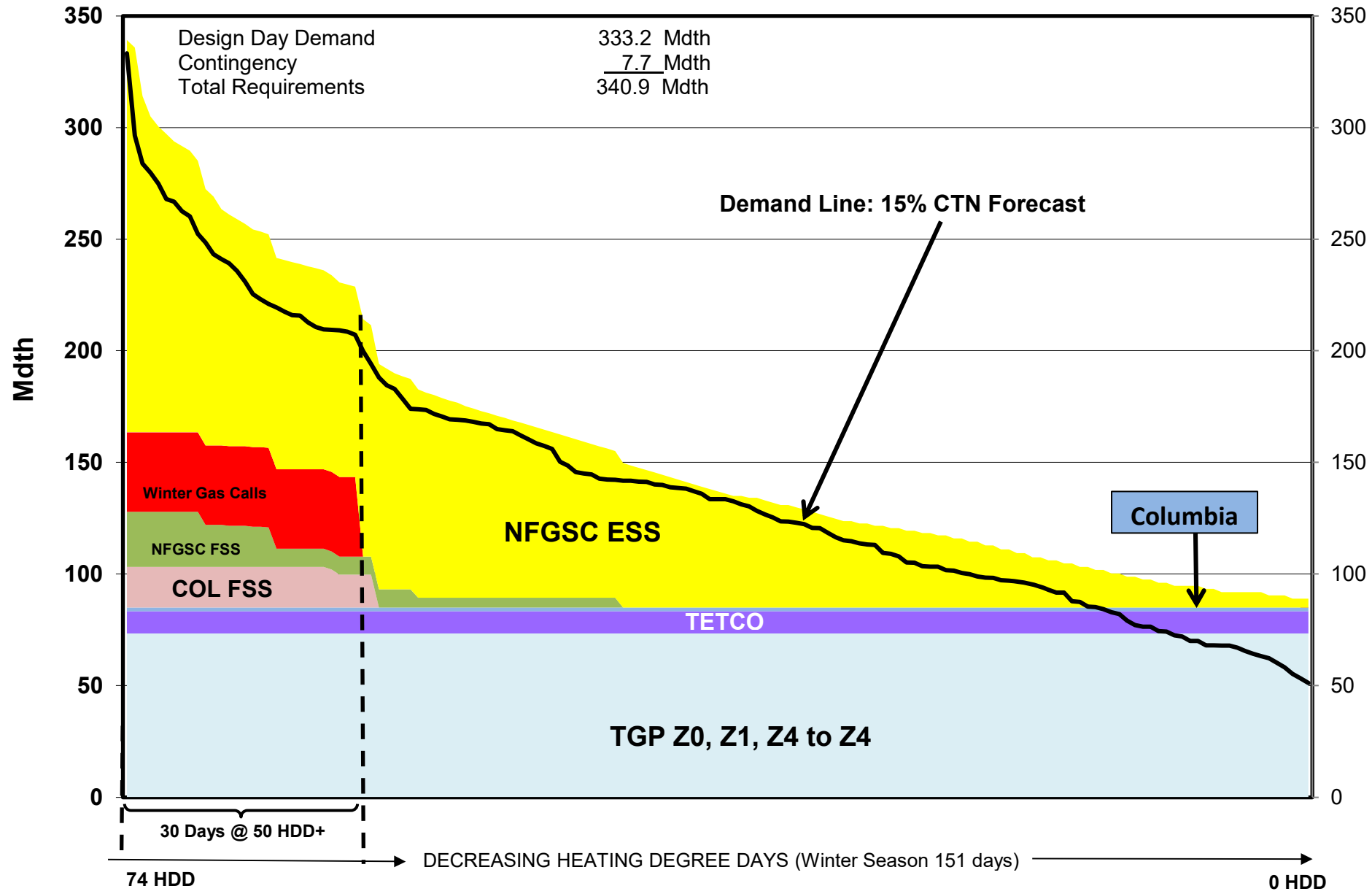
System Map

EXISTING FACILITIES		LEGEND	
NFG SUPPLY PIPELINE	JOINT OWNERSHIP PIPELINES	OTHER PIPELINE LOCATION APPROXIMATE	
MARKET AREA POOLING POINT	INTERCONNECT	POINTS OF INTEREST	NFG SUPPLY COMPRESSOR STATION
			NF STORAGE AREA

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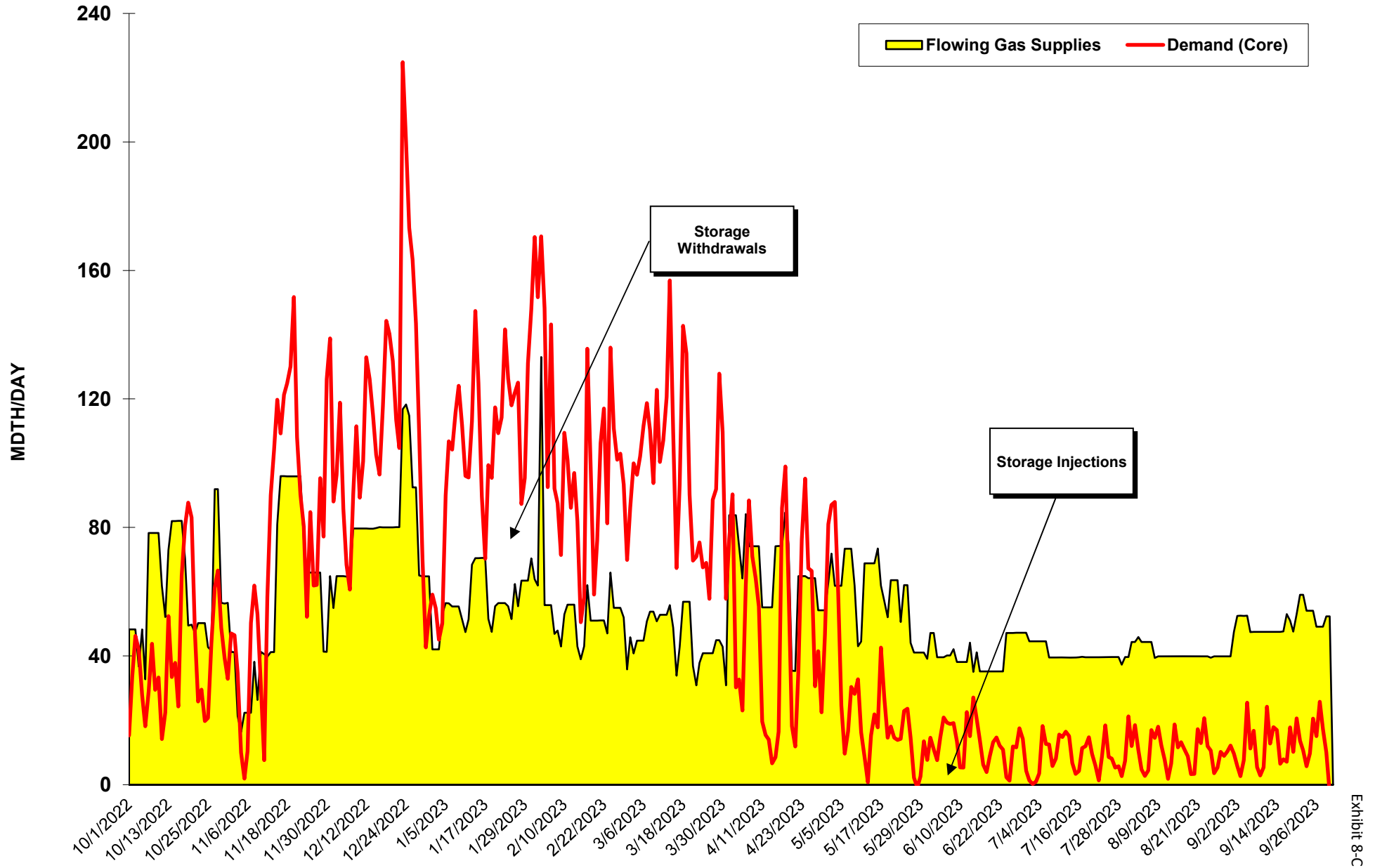
NFG SYSTEM MAP 20230608.mxd

National Fuel Gas Distribution Corporation - Pennsylvania 2024-2025 Load Duration Curve



Design Day based on 74 HDD: Forecast (June 2023)

NFGDC PA - Gas Supply vs Demand



National Fuel Gas Distribution Corporation - Pennsylvania Division

Calculation of Retained Capacity and SATS Released Transmission Capacity ("RTC") Mix

Capacity retained by NFGDC to meet temperature variability and peaking requirements of Sales and SATS customers

Winter 2024-2025 Design Peak Day 74 DD Requirement		Dth/day
Retail Sales		279,794
SATS Service		25,871
City gate total		305,665
Less: Base Load *		(14,557)
Heating load 74 DD		291,108
Heating load per DD		3,934

Calculation of Retained Capacity for 12 DD (74-62 DD)		Dth/day	
Total Retained Capacity Requirement	Heating load per DD*12 DD	47,208	
Contracts selected to meet RTC requirement			MSQ
	NFGSC FSS O02432	10,666	200,000
	NFGSC ESS G00539	36,542	1,705,707
Total Retained Capacity		47,208	

Calculation of Capacity Requirement for 62 DD		Dth/day	DD provided
City gate Total		305,665	74
Less: Retained Capacity		47,208	12
Difference		258,457	62

Calculation of Released Transmission Capacity (RTC) Mix		Dth/day	Daily mix
Upstream Capacity **		117,196	45%
ESS		141,261	55%
Total		258,457	100%

* Forecast for average day during July & August 2025

** Upstream Capacity is TGP, TETCO, Columbia FTS and FSS, NFGSC FSS; net of NFGSC retainage for fuel and line loss

**National Fuel Gas Distribution Corporation
Pennsylvania Division
GAS COST MANAGEMENT PLAN**

Volatility mitigation through price diversification of gas supplies.

- I.** Forward pricing: Fix or cap approximately 12% of forecasted winter (November – March) demand requirements. Pricing will be established over the preceding summer (April – October).
- II.** Storage: Approximately 40% of winter demand requirements are served from storage, these supplies are priced at a weighted average cost of storage gas.
- III.** Monthly Pricing: Approximately 24% of winter and 50% of summer forecasted demand requirements shall be priced at a mix of index and bid week negotiated (cash) prices.
- IV.** Daily Pricing: Approximately 24% of winter and 50% of summer forecasted demand requirements shall be priced at a mix of index and negotiated (cash) prices.

	Winter	Summer
Forward	12%	0%
Storage	40%	0%
Monthly	24%	50%
Daily	24%	50%
	100%	100%

The timing of when to fix or cap prices, and the percentages indicated above, are general guidelines based on normal weather and operating conditions. Adjustments may be necessary to accommodate operational requirements and unanticipated events.

Revision Date: November 1, 2018

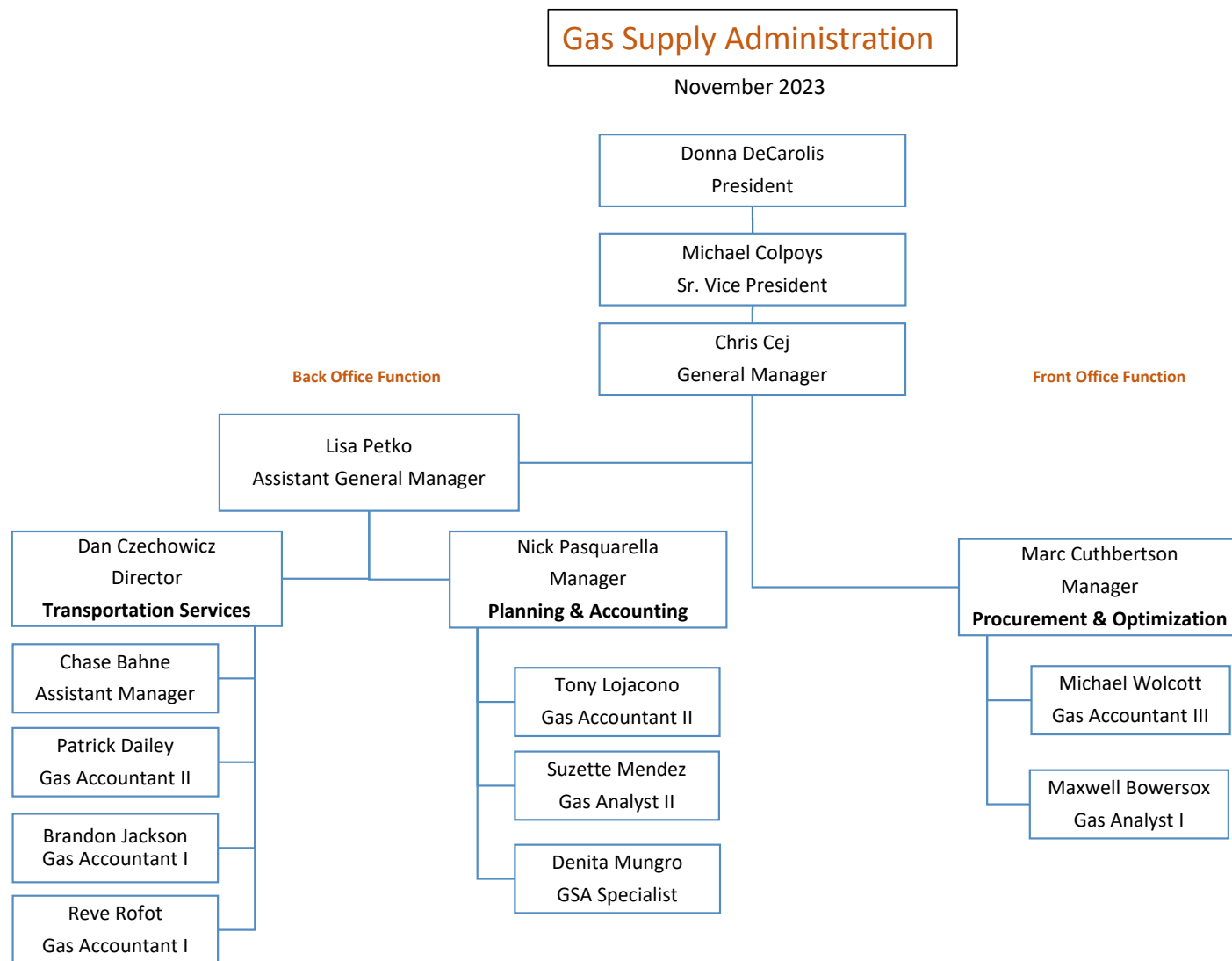
National Fuel Gas Distribution Corporation
Pennsylvania Division
GAS COST MANAGEMENT PLAN
Effective: April 1, 2025

Volatility mitigation through price diversification
(100% of forecasted monthly purchases)

- I.** Forward pricing: Winter fixed price or caps for approximately 12% of forecasted winter (November – March) demand requirements. Prices for these winter delivery quantities will be established over the preceding summer (April – October). Summer fixed price for approximately 15%-20% of forecasted summer (April – October) demand requirements and storage fill requirements. Prices for these summer delivery quantities will be established over the preceding summer (April – October).
- II.** Storage: Approximately 40% of winter demand requirements are served from storage, these supplies are priced at the previous summer's (April – October) average purchase price.
- III.** Monthly Pricing: Approximately 24% of winter and 30%-35% of summer forecasted demand requirements shall be priced at a mix of index and bid week negotiated (cash) prices.
- IV.** Daily Pricing: Approximately 24% of winter and 50% of summer forecasted demand requirements shall be priced at a mix of index and negotiated (cash) prices.

	Winter	Summer
Forward	12%	15-20%
Storage	40%	0%
Monthly	24%	30-35%
Daily	24%	50%
	100%	100%

The timing of when to fix or cap prices, and the percentages indicated above, are general guidelines based on normal weather and operating conditions. Adjustments may be necessary to accommodate operational requirements and unanticipated events.



NATIONAL FUEL GAS DISTRIBUTION CORPORATION

53.64 (c) (7) A list of off system sales, including transportation, storage or capacity releases by the utility at less than the weighted average price of gas, or at less than the original contract cost of transportation, storage or capacity supplied to the utility for its own customers.

A. Off-System Sales

Distribution did not have any Off-System Sales during the period of December 2022 through November 2023.

B. Capacity Releases

Attached as Exhibit 9-A and Exhibit 9-B are reports detailing all Transportation and Storage releases that were in effect during the historic period. These Exhibits include releases made pursuant to Distribution's state-approved marketer program and are identified as "Pennsylvania Energy Select" releases.

For further details concerning National Fuel Gas Distribution Corporation's capacity releases and off-system sales, refer to PGC Exhibit No. 8.

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

12/1/2022 - 11/30/2023

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

12/1/2022 - 11/30/2023

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

12/1/2022 - 11/30/2023

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023

[illegible]

**National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023**

[illegible]

12/1/2022 - 11/30/2023

[illegible]

12/1/2022 - 11/30/2023

[illegible]

National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023

[illegible]

12/1/2022 - 11/30/2023

[illegible]

National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023

[illegible]

National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023

[illegible]

12/1/2022 - 11/30/2023

[illegible]

12/1/2022 - 11/30/2023

[illegible]

National Fuel Distribution Corporation
Transportation Capacity Release Report
12/1/2022 - 11/30/2023

Pipeline	Release Type	Begtime	Endtime	Bus. Assoc.	Release K#	Rec Meter	Del Meter	Release Award #	Prearranged	Biddable	Recallable	Daily Volume	Monthly Flow	Value

End Confidential

12/1/2022 - 11/30/2023

[illegible]

National Fuel Distribution Corporation
Storage Capacity Release Report
12/1/2022 - 11/30/2023

[illegible]

National Fuel Distribution Corporation
Storage Capacity Release Report
12/1/2022 - 11/30/2023

[illegible]

National Fuel Distribution Corporation
Storage Capacity Release Report
12/1/2022 - 11/30/2023

[illegible]

National Fuel Distribution Corporation
Storage Capacity Release Report
12/1/2022 - 11/30/2023

[illegible]

National Fuel Distribution Corporation
Storage Capacity Release Report
12/1/2022 - 11/30/2023

[illegible]

12/1/2022 - 11/30/2023

[illegible]

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

53.64 (c) (8) A list of agreements to transport gas by the utility through its system, for other utilities, pipelines, or jurisdictional customers including the quantity and price of the transportation.

National Fuel Gas Distribution Corporation maintains transportation agreements with its Daily Metered customers and Monthly Metered Natural Gas Suppliers who are responsible for the delivery requirements and imbalance resolution of Monthly Metered Transportation customers. Volumes are provided in summary format by revenue class. Please refer to PGC Exhibit No. 11 for transportation quantities by revenue class and service class. In addition, it should be noted that PGC Exhibit No. 11 includes prices by service class.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

- 53.64 (c) (9) A schedule depicting historic monthly end-user transportation throughput by customer. Each customer or account shall be identified solely by a unique alphanumeric code, the key to which may be provided subject to §5.423 (relating to orders to limit availability of proprietary information).**

Daily Metered Transportation volumes and class type are listed on page 2. Monthly Metered Transportation Aggregation/SATC volumes and class type are listed on pages 3 and 4. The current base rates for Transportation Service for National Fuel Gas Distribution Corporation are shown on pages 5 through 6 extracted from Distribution's Tariff Gas - Pa. P.U.C. No. 9.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
TRANSPORTATION (CUSTOMER-OWNED GAS) SERVICE
VOLUMES IN MCF

Daily Metered Transportation Volumes

Commercial	Service Class Description	# of Customers at Nov 2023	2022/12 Dec-22	2023/01 Jan-23	2023/02 Feb-23	2023/03 Mar-23	2023/04 Apr-23	2023/05 May-23	2023/06 Jun-23	2023/07 Jul-23	2023/08 Aug-23	2023/09 Sep-23	2023/10 Oct-23	2023/11 Nov-23	Total
Total Commercial DMT	Large Com/Pub Authority - DMT	13	67,005.9	62,277.1	62,120.6	55,997.2	61,335.0	49,526.1	58,846.6	48,772.1	45,805.8	48,853.5	48,425.4	59,867.2	668,832.5

Industrial	Service Class Description	# of Customers at Nov 2023	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Total
IVIS	Intermediate Volume Industrial Service - DMT	23	69,859.2	85,153.4	90,166.0	80,308.2	85,298.5	58,817.3	51,944.4	41,091.0	36,742.5	45,603.9	41,959.7	54,918.3	741,862.4
	Large Com/Public Authority - DMT	0	0.0	16,255.0	16,281.0	13,936.0	15,244.0	11,654.0	0.0	0.0	0.0	0.0	0.0	0.0	73,370.0
LVIS	Large Volume Industrial Service - DMT	20	156,776.5	219,109.8	188,268.5	185,301.7	183,813.7	185,624.4	134,392.8	113,129.7	98,461.3	111,041.0	117,375.2	226,258.8	1,919,553.4
	Large Volume Industrial Service - DMT Flex	0	6,718.0	7,120.0	6,191.0	5,100.0	5,063.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30,192.0
LIS	Large Industrial Service - DMT	10	388,352.7	431,982.2	471,651.3	455,525.7	453,308.6	381,622.6	310,617.1	291,626.0	224,168.0	555,222.0	491,100.0	345,686.8	4,800,863.0
	Large Industrial Service - DMT Flex	7	310,243.0	119,955.0	358,875.0	325,936.0	375,878.0	304,594.0	296,868.0	270,154.0	335,701.0	49,723.0	45,179.0	304,187.0	3,097,293.0
	Large Manufacturing Service - DMT Flex	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	128,338.3	157,461.8	0.0	285,800.1
DMT LMTS	Large Manufacturing Service - DMT	1	156,260.4	184,812.2	174,817.8	213,723.1	209,381.6	100,130.2	82,320.9	95,807.0	123,889.0	0.0	0.0	117,772.1	1,458,914.3
Total Industrial DMT		61	1,088,209.8	1,064,387.6	1,306,250.6	1,279,830.7	1,327,987.4	1,042,442.5	876,143.2	811,807.7	818,961.8	889,928.2	853,075.7	1,048,823.0	12,407,848.2

Public Authority	Service Class Description	# of Customers at Nov 2023	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Total
Total Public Authority DMT	Large Com/Pub Authority - DMT	2	21,617.1	27,160.0	26,743.7	23,157.6	24,755.8	16,953.2	5,663.9	7,543.7	7,068.8	6,533.7	6,909.6	21,183.0	195,290.1

Total Daily Metered Transportation Volumes		76	1,176,832.8	1,153,824.7	1,395,114.9	1,358,985.5	1,414,078.2	1,108,921.8	940,653.7	868,123.5	871,836.4	945,315.4	908,410.7	1,129,873.2	13,271,970.8

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
TRANSPORTATION (CUSTOMER-OWNED GAS) SERVICE
VOLUMES IN MCF

Monthly Metered Transportation Volumes

		# of Customers at Nov 2023	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Total
Residential	Description														
	Residential	454	13,957.5	18,656.1	17,386.1	15,323.7	12,670.1	6,919.6	2,782.1	1,132.8	957.3	1,222.1	2,503.5	7,088.3	100,599.2
	Small Com/Pub Auth <250 Mcf/Year	5	57.5	73.5	54.1	54.8	42.3	20.3	22.9	15.7	18.2	15.9	25.5	46.9	447.6
	Small Com/Pub Auth 250-1000 Mcf/Year	19	1,434.5	1,832.4	1,537.1	1,247.7	949.8	659.6	346.6	250.1	231.3	289.9	421.6	753.1	9,953.7
	Large Com/Public Authority	24	11,989.0	18,625.6	17,792.8	16,666.9	15,997.2	9,811.0	6,717.1	3,643.6	2,916.9	3,048.9	3,172.8	7,013.2	110,381.8
Total Residential MMNGS		502	27,438.5	39,187.6	36,770.1	33,293.1	29,659.4	17,410.5	9,868.7	5,042.2	4,123.7	4,576.8	6,123.4	14,901.5	221,382.3
Total Residential SATC	SATC Residential	16,302	236,524.8	275,973.9	254,113.0	231,177.7	171,355.1	105,934.2	46,615.0	26,457.6	24,977.9	28,836.5	49,112.8	108,912.2	1,559,990.7
	SATC Residential - E	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Small Com/Pub Auth <250 Mcf/Year	1	23.6	25.4	41.3	38.6	38.2	25.1	16.2	13.6	11.8	13.0	13.9	14.3	275.0
	Small Com/Pub Auth 250-1000 Mcf/Year	1	0.0	0.0	75.6	67.3	26.5	30.9	16.0	6.8	5.0	5.4	8.0	27.3	268.8
		16,304	236,548.4	275,999.3	254,229.9	231,283.6	171,419.8	105,990.2	46,647.2	26,478.0	24,994.7	28,854.9	49,134.7	108,953.8	1,560,534.5
Total Residential		16,806	263,986.9	315,186.9	291,000.0	264,576.7	201,079.2	123,400.7	56,515.9	31,520.2	29,118.4	33,431.7	55,258.1	123,855.3	1,788,930.0
Commercial	Residential	6	163.2	191.2	167.8	148.5	124.8	76.0	60.8	46.8	61.6	48.3	56.6	105.8	1,251.4
	Small Com/Pub Auth <250 Mcf/Year	948	16,864.8	24,929.4	23,782.2	19,235.1	13,505.4	6,699.3	2,750.0	1,566.3	1,316.7	1,592.6	2,847.9	7,780.5	122,870.2
	Small Com/Pub Auth 250-1000 Mcf/Year	1,061	75,839.9	98,576.7	93,006.9	82,172.1	64,223.3	36,484.0	19,355.7	11,988.2	11,529.6	13,029.5	18,563.2	39,466.0	564,235.1
	Large Com/Public Authority	742	294,118.7	397,744.4	370,957.0	339,752.1	320,860.8	197,583.9	138,341.6	87,197.7	76,766.6	83,559.9	93,450.5	180,352.2	2,580,685.4
		2,757	386,986.6	521,441.7	487,913.9	441,307.8	398,714.3	240,843.2	160,508.1	100,799.0	89,674.5	98,230.3	114,918.2	227,704.5	3,269,042.1
Total Commercial MMNGS															
Total Commercial SATC	SATC Residential	0	73.6	37.4	60.1	51.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	222.1
	SATC Small Com/Pub Auth <250 Mcf/Year	809	14,883.1	18,738.7	18,005.2	14,692.6	10,200.6	5,012.0	1,908.4	1,059.6	825.7	1,139.1	2,090.8	5,604.3	94,160.1
	SATC Small Com/Pub Auth 250-1000 Mcf/Year	347	20,848.0	26,758.2	25,236.4	22,669.6	16,019.2	9,771.5	5,270.9	3,680.7	3,523.0	3,967.5	5,390.8	11,370.7	154,506.5
	SATC Large Com/Public Authority	49	6,439.3	9,332.6	7,938.8	7,548.8	6,216.7	4,347.7	3,159.1	2,172.5	2,130.8	2,510.8	2,836.6	6,853.1	61,486.8
		1,205	42,244.0	54,866.9	51,240.5	44,962.0	32,436.5	19,131.2	10,338.4	6,912.8	6,479.5	7,617.4	10,318.2	23,828.1	310,375.5
Total Commerical		3,962	429,230.6	576,308.6	539,154.4	486,269.8	431,150.8	259,974.4	170,846.5	107,711.8	96,154.0	105,847.7	125,236.4	251,532.6	3,579,417.6

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
TRANSPORTATION (CUSTOMER-OWNED GAS) SERVICE
VOLUMES IN MCF

Monthly Metered Transportation Volumes

		# of Customers at Nov 2023	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Total
Industrial	Description														
	Small Volume Industrial Service	57	5,860.6	8,588.6	8,361.8	6,703.9	3,847.7	1,632.8	497.8	183.2	119.2	178.5	447.0	2,005.1	38,426.2
	Intermediate Volume Industrial Service	271	222,608.6	283,300.0	271,513.5	256,998.5	264,852.3	175,980.0	144,370.3	129,380.9	134,337.7	120,022.7	139,242.2	185,212.9	2,327,819.6
	Large Industrial Service	1	28,387.0	30,458.0	31,989.0	27,624.0	27,900.0	30,530.0	28,364.0	28,241.0	27,362.0	27,381.0	20,152.0	28,669.0	337,057.0
Total Industrial MMNGS	Large Volume Industrial Service	9	42,049.7	55,616.8	47,085.5	49,111.8	51,395.9	44,920.9	52,917.4	62,231.0	69,453.7	72,552.1	68,603.8	73,132.4	689,071.0
		338	298,905.9	377,963.4	358,949.8	340,438.2	347,995.9	253,063.7	226,149.5	220,036.1	231,272.6	220,134.3	228,445.0	289,019.4	3,392,373.8
	SATC Small Volume Industrial Service	14	1,050.3	1,526.1	1,497.4	1,208.0	871.6	445.4	142.1	42.0	51.6	42.3	42.8	266.7	7,186.3
	SATC Intermediate Volume Industrial Service	4	823.0	1,031.0	648.0	1,077.0	1,462.9	758.0	284.0	137.2	110.7	171.0	289.3	869.3	7,661.4
Total Industrial SATC		18	1,873.3	2,557.1	2,145.4	2,285.0	2,334.5	1,203.4	426.1	179.2	162.3	213.3	332.1	1,136.0	14,847.7
Total Industrial		356	300,779.2	380,520.5	361,095.2	342,723.2	350,330.4	254,267.1	226,575.6	220,215.3	231,434.9	220,347.6	228,777.1	290,155.4	3,407,221.5
Public Authority	Small Com/Pub Auth <250 Mcf/Year	141	2,333.4	2,820.6	3,107.3	2,663.6	1,960.5	1,065.4	487.5	217.3	332.8	167.9	494.5	1,252.5	16,903.3
	Small Com/Pub Auth 250-1000 Mcf/Year	152	9,184.9	11,823.3	11,974.1	10,522.9	8,160.7	4,054.7	2,854.3	986.3	917.2	781.1	1,405.9	4,643.7	67,309.1
	Large Com/Public Authority	264	192,882.0	279,669.9	260,757.3	243,557.9	245,319.3	138,319.5	89,155.4	44,575.2	37,643.8	39,766.9	48,222.5	108,351.4	1,728,221.1
	Large Com/Public Authority - E	0													0.0
Total Public Authority MMNGS		557	204,400.3	294,313.8	275,838.7	256,744.4	255,440.5	143,439.6	92,497.2	45,778.8	38,893.8	40,715.9	50,122.9	114,247.6	1,812,433.5
Total Public Authority SATC	SATC Small Com/Pub Auth <250 Mcf/Year	35	666.0	844.1	728.9	579.1	414.4	197.4	56.0	23.6	18.1	27.4	77.8	248.0	3,880.8
	SATC Small Com/Pub Auth 250-1000 Mcf/Year	21	1,458.3	1,784.7	1,443.9	1,435.1	987.0	463.6	290.9	314.3	107.3	115.3	227.0	615.2	9,242.6
	SATC Large Com/Public Authority	3	130.5	142.0	145.6	172.7	152.6	117.7	87.0	21.6	63.1	14.9	72.3	115.8	1,235.8
		59	2,254.8	2,770.8	2,318.4	2,186.9	1,554.0	778.7	433.9	359.5	188.5	157.6	377.1	979.0	14,359.2
Total Public Authority		616	206,655.1	297,084.6	278,157.1	258,931.3	256,994.5	144,218.3	92,931.1	46,138.3	39,082.3	40,873.5	50,500.0	115,226.6	1,826,792.7
Total MMNGS/SATC		21,740	1,200,651.8	1,569,100.6	1,469,406.7	1,352,501.0	1,239,554.9	781,860.5	546,869.1	405,585.6	395,789.6	400,500.5	459,771.6	780,769.9	10,602,361.8
Grand Total MMNGS/SATC & DMT		21,816	2,377,484.6	2,722,925.3	2,864,521.6	2,711,486.5	2,653,633.1	1,890,782.3	1,487,522.8	1,273,709.1	1,267,626.0	1,345,815.9	1,368,182.3	1,910,643.1	23,874,332.6

National Fuel Gas Distribution Corporation
Pennsylvania Division
Current Rates

Monthly Metered Transportation Service

Monthly Rates per Mcf:

Residential	\$3.3311
Small Com/Pub <250 Mcf per year	\$2.6694
Small Com/Pub 250-1000 Mcf per year	\$2.4255
Large Com/Pub Authority	\$2.0322
Small Volume Industrial Service	\$2.4422
Intermediate Volume Industrial Service	\$1.7047
Large Volume Industrial Service	\$1.3943
Large Industrial Service	\$0.9693

Daily Metered Transportation Service

Monthly Rates per Mcf:

Residential	\$2.9611
Small Com/Pub <250 Mcf per year	\$2.2994
Small Com/Pub 250-1000 Mcf per year	\$2.0555
Large Com/Pub Authority	\$1.6622
Small Volume Industrial Service	\$2.0722
Intermediate Volume Industrial Service	\$1.3347
Large Volume Industrial Service	\$1.0243
Large Industrial Service	\$0.5993
Large Manufacturing Service	\$0.5993

National Fuel Gas Distribution Corporation
Pennsylvania Division
Current Rates

Small Aggregation Transportation Customer (SATC) Service

Residential:

Basic Service Charge	\$14.00
Per Mcf	\$3.3405

Small Com/Pub Authority (< 250 Mcf per year):

Basic Service Charge	\$27.00
Per Mcf	\$2.6788

Small Com/Pub Authority (250-1000 Mcf per year):

Basic Service Charge	\$37.00
Per Mcf	\$2.4349

Large Commercial/Public Authority:

Basic Service Charge	\$151.00
Per Mcf	\$2.0461

Small Volume Industrial Service:

Basic Service Charge	\$82.00
Per Mcf	\$2.4516

Intermediate Volume Industrial Service:

Basic Service Charge	\$252.00
Per Mcf	\$1.7141

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

53.64 (c) (10) A schematic system map, locating and identifying by name, pressure and capacity all interstate or intrastate transmission pipeline connections, compressor stations, utility transmission or distribution mains 6 inches or larger in size, storage facilities, including maximum daily injection and withdrawal rates, production fields and individual industrial or transportation customers which represents 5% or more of total system throughput in a month. Each customer or account shall be identified solely by a unique alphanumeric code, the key to which may be provided subject to §5.423.

In order to show all Distribution's Pennsylvania Division pipelines that are 6" and larger, Distribution would have to provide its detailed operating maps, which exceed 4,000 sheets.

Upon request, Distribution will provide an oversized schematic map of the National Fuel Gas System that shows the locations and diameter sizes of certain National Fuel Gas Supply Corporation ("Supply"), Distribution and upstream pipeline major transmission lines, and Distribution's major market areas.

Listed below are select supporting sheets from Supply's FERC Gas Tariff under Rate Schedule EFT that identify (1) pressure and capacities at Supply pipeline connections, (2) pressures at Supply's delivery points to Distribution and (3) storage injection and withdrawal levels for Supply's storages. These tariff sheets can be accessed through Supply's website.

<https://informationalpostings.natfuel.com/supply/docs/SupplyTariff.pdf#titlesheet>

Part 6 – Rate Schedules, Schedule 6.030: EFT Rate Schedule

§ 1 – Availability

§ 2 – Applicability and Character of Service

§ 3 – Rate

§ 4 – Operating Protocol for EFT Service

§ 5 – General Terms & Conditions

Distribution had two customers that represented 5% or more of Distribution's Pennsylvania Division throughput in a month.

(BEGIN CONFIDENTIAL PORTION)

(END CONFIDENTIAL PORTION)

Explanation of Rate Allocation and
Rate Structure Changes

National Fuel Gas Distribution Corporation (“Distribution”) has implemented a system wide customer choice program and has updated purchased gas cost charges associated with that program in addition to the modifications to Distribution’s Monthly Metered Transportation (“MMT”) and Daily Metered Transportation (“DMT”) rates to reflect the Federal Energy Regulatory Commission’s Order 636 as detailed in PGC Exhibit No. 24.

On October 30, 1998, Distribution filed its system wide customer choice program, which made aggregated transportation services available to all of Distribution’s small volume customers. The Commission permitted Distribution’s system wide customer choice program to become effective March 4, 1999. Distribution has been providing all customers with the opportunity to choose an alternative natural gas supplier (“NGS”) since April 1, 1999. Under Distribution’s system wide choice program, qualified NGSs other than Distribution are able to serve the aggregated gas supply requirements of their customers. Retail customers receive transportation service under Distribution’s Small Aggregation Transportation Customer Service (“Rate Schedule SATC”). NGSs are required to qualify for service under Distribution’s Small Aggregation Transportation Supplier Service (“Rate Schedule SATS”).

On October 1, 1999, Distribution filed its Restructuring Filing in compliance with the Natural Gas Choice and Competition Act (“Act”). 66 Pa. C.S. §§ 2201-12. In that filing Distribution proposed, among other things, modifications to the upstream capacity allocations associated with the system wide choice program. On June 8, 2000 the Commission adopted an Order in Distribution’s Restructuring proceeding. This filing reflects the changes to SATC and SATS service approved by the Commission in Distribution’s Restructuring proceeding. This filing also reflects the changes in Distribution’s Pennsylvania Division’s upstream capacity as explained in Distribution’s “Petition for Approval of Amendment to Reliability Plan and Approval of Contract for Storage Capacity” filed with the Commission on September 8, 2000. Specifically, the following capacity allocations were utilized in determining the purchased gas costs to include in SATC rates.

Percent of NGS Peak Day Peak Day Delivery Requirements <u>Met by Upstream Capacity</u>		<u>Capacity</u>
1.	55%	National Fuel Gas Supply Corporation (“NFGSC”) storage and associated transmission released to NGS

2. 45% Mandatory release of upstream capacity

On June 29, 2010 the Commission approved the Purchase of Receivable Program. The Company will purchase NGSs account receivables for SATC customers with annual consumption less than 1,000 Mcf per year. The Company also established the Merchant Function Charge which unbundles the uncollectible cost component associated with purchased gas costs from delivery charges and includes such uncollectible cost recovery from the Natural Gas Supply and Gas Adjustment Charge gas cost rates.

On November 9, 2012, Distribution filed a revision to Tariff Gas – Pa. P.U.C. No. 9 (R-2012-2333775) proposing to unbundle natural gas procurement costs from the Company’s distribution rates and recover these costs through a Gas Procurement Charge (“GPC”) that are to be included in the Company’s Price To Compare. The parties in this proceeding agreed to a settlement which set the GPC at \$0.1050 / Mcf. The settlement was approved by the Commission at the Public Meeting held on May 23, 2013 and the tariff became effective June 1, 2013.

On March 2, 2017, Distribution filed Supplement No. 184 to Tariff Gas - Pa. P.U.C. No. 9 to comply with Act 47 of the Public Utility Code (66 PA. C. S.) which allowed for elimination of the migration rider. The tariff language was revised so the E-factor is only applicable to sales customers. On March 17, 2017, the Secretary sent Distribution a letter stating that Commission Staff reviewed the tariff revisions and found that suspension or further investigation does not appear warranted at this time. The tariff became effective on May 1, 2017.

PGC Exhibit No. 13A provides the calculation of the purchased gas costs associated with temperature swing and peaking capacity that are included in SATC rates.

National Fuel Gas Distribution Corporation
 Pennsylvania Division
 Computation of Purchased Cost
 Of Gas Transported Under the Rate Schedule
 Small Aggregation Transportation Customer Service
 On or After Aug 1, 2024

PGC Exhibit No. 13A
 Page 1

Computation Year: Twelve Months Ended July 2024

		Total Pa. Monthly Capacity Dth (A)	Applicable # of Months in Rate Yr (B)	Total Pa Annual Capacity Dth (C)	Demand Rate \$/Dth (D)	Total Demand Cost (E=DxC)
Temperature Swing/Peaking Capacity Costs						
NFGSC EFT Capacity for Temperature Swing/Peaking	1/	54,045	12	648,540.0	\$ 8.9534	\$ 5,806,638
NFGSC ESS Delivery Costs for Temperature Swing/Peaking	1/	43,379	12	520,548.0	\$ 4.2337	\$ 2,203,844
NFGSC ESS Capacity Costs for Temperature Swing/Peaking	2/	2,024,844	12	24,298,132.8	\$ 0.0748	\$ 1,817,500
NFGSC FSS Delivery Costs for Temperature Swing/Peaking		10,666	12	127,992.0	\$ 4.0694	\$ 520,851
NFGSC FSS Capacity Costs for Temperature Swing/Peaking		200,000	12	2,400,000.0	\$ 0.0713	\$ 171,120
Total Temperature Swing/Peaking Costs						\$ 10,519,953
Total Distribution Charge Costs						\$ 10,519,953
Volumes (Mcf)						
SATC Volumes						2,012,390
Sales Volumes						<u>21,817,752</u>
Total Volumes						23,830,142
Distribution Charge Gas Cost (\$/Mcf)						<u>\$ 0.4415</u>

1/ Includes 6,837 Dth of Contingency Capacity

2/ Includes 319,137 Dth of Contingency Capacity

3/ MSQ divided by NFGSC ESS G00539 Dth per day

National Fuel Gas Distribution Corporation
Pennsylvania Division

53.64 (c) (12) – Five Year Consecutive Three Day Peak Data by Customer Class

A schedule depicting the most recent five year consecutive three day peak data by customer class (or such other historic peak day data as is actually utilized for system planning), daily volumetric throughput by customer class (including end-user transportation throughput), gas interruptions and high, low and average temperature during each day.

Page 2 of this Exhibit provides consecutive three day peak day throughput data (retail sales and transportation service), allocated by customer class, for the most recent five years. National Fuel Gas Distribution Corporation's Pennsylvania Division has not had any gas interruptions during the most recent five years.

In addition, the high, low and average temperatures for each of the three days are shown.

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
FIVE YEAR CONSECUTIVE THREE DAY PEAK DATA BY CUSTOMER CLASS
VOLUMES IN MCF**

NOV-OCT						High	Low	Avg	Gas
2022-2023	Residential	Commercial	Industrial	Pub Auth	Total	Temp	Temp	Temp	Interruptions
December 23, 2023	181,715	70,695	83,204	23,516	359,130	12	0	6	0
December 24, 2023	164,952	64,058	78,517	21,376	328,902	15	12	14	0
December 25, 2023	159,724	62,078	61,099	20,697	303,598	20	12	16	0
NOV-OCT									
2021-2022	Residential	Commercial	Industrial	Pub Auth	Total	High	Low	Avg	Gas
January 26, 2022	159,705	60,375	80,563	19,617	320,259	Temp	Temp	Temp	Interruptions
January 27, 2022	132,456	50,339	74,014	16,353	273,162	19	6	13	0
January 28, 2022	144,252	54,618	76,378	17,748	292,996	28	5	17	0
						29	13	21	0
NOV-OCT									
2020-2021	Residential	Commercial	Industrial	Pub Auth	Total	High	Low	Avg	Gas
February 7, 2021	130,601	50,804	64,093	15,280	260,778	Temp	Temp	Temp	Interruptions
February 8, 2021	126,707	49,372	68,594	14,877	259,549	23	16	20	0
February 9, 2021	139,433	53,957	72,129	16,264	281,784	24	13	19	0
						25	20	23	0
NOV-OCT									
2019-2020	Residential	Commercial	Industrial	Pub Auth	Total	High	Low	Avg	Gas
January 19, 2020	132,442	47,681	66,678	15,860	262,662	Temp	Temp	Temp	Interruptions
January 20, 2020	126,275	45,744	74,897	15,112	262,029	34	22	28	0
January 21, 2020	134,181	48,399	79,822	16,058	278,460	26	20	23	0
						27	20	24	0
NOV-OCT									
2018-2019	Residential	Commercial	Industrial	Pub Auth	Total	High	Low	Avg	Gas
January 30, 2019	186,957	68,423	98,962	21,704	376,045	Temp	Temp	Temp	Interruptions
January 31, 2019	178,294	65,587	89,499	20,706	354,086	10	-4	3	0
February 1, 2019	172,260	62,998	81,926	19,968	337,151	8	-4	2	0
						15	2	9	0

National Fuel Gas Distribution Corporation
Pennsylvania Division

53.64 (c) (13) – Peak Day Methodology to Meet Future Demands

Identification and support for any design peak day methodology utilized to project future gas demands and any studies supporting the validity of such methodology.

National Fuel Gas Distribution Corporation's ("Distribution" or the "Company") projected 2025 design peak day gas demands under an extreme temperature scenario can be found on page 3. Detailed calculations and additional supporting documentation can be found on pages 4 through 19.

A design peak day analysis is performed by Distribution for capacity planning purposes and to allocate costs to customer classes. The use of the term "design peak day," by Distribution, refers to a calculated level of gas usage, based on the day in a winter season that has the highest number of degree days (i.e., the day with the lowest average temperature for which Distribution plans gas supplies and pipeline capacity). A peak day, in contrast, is the historical day of greatest gas usage in a winter period, which may not have occurred on the coldest day of the year. The peak may not occur on the coldest day of the year for several reasons (e.g., if the coldest day was not a business day and many businesses were not operating, the peak day might not be the coldest day).

Data based on 74 heating degree days is provided (page 19) since this was used for design peak day planning purposes. Based on the experience of the most recent 30 years, the Pennsylvania Division has experienced extreme heating degree days of 74. Therefore, it is realistic to expect similar extreme days to occur in the future.

Pages 4 through 12 represent the work papers used to compute the design peak day requirements. For the residential, commercial and public authority heat sensitive classes (both retail sales and transportation service), Distribution utilizes a method of extracting a base load volume and computing a daily heating volume for the temperature used in the design peak day analysis (74 degree days). Industrial classes are not generally sensitive to temperature, therefore, the design peak day sales are computed based on an operating schedule approach. For Small and Intermediate Volume Industrial Service, Distribution utilizes an operating schedule of 21 working days in a month. For Large Volume Industrial Service, Large Industrial Service, and Daily Metered Large Manufacturing Transportation Service, Distribution utilizes the actual operating schedule of each individual company (actual operating schedules are shown on pages 11 and 12 of this Exhibit).

The following examples are provided to illustrate the mechanics of the operating schedule calculations described above:

- Customer 19 on page 11 of this Exhibit operates 24 hours per day, 7 days per week. Customer 27's peak day consumption of 440 Mcf is equal to 13,649 Mcf of monthly consumption divided by an operating schedule factor of 31 days. The operating schedule factor is calculated by multiplying 7 days per week by 4.429 weeks. 4.429 weeks is calculated as 31 days divided by 7 days in a week.
- Customer 5 on page 12 of this Exhibit operates 24 hours per day, 5 days per week. Customer 13's peak day consumption of 1,027 Mcf is equal to 22,745 Mcf of monthly consumption divided by an operating schedule factor of 22.143 days. The operating schedule factor is calculated by multiplying 5 days per week by 4.429 weeks. 4.429 weeks is calculated as 31 days divided by 7 days in a week.

Page 9 provides the monthly gas requirements used to develop the design peak day and page 10 provides winter retail requirements for 2024-2025. The methodology employed to project gas requirements is similar to the methodology used in Distribution's last base rate proceeding, at docket number R-2022-3035730.

Econometric modeling results are also provided in this Exhibit, at the following page numbers:

- Residential – Pages 13 and 16
- Commercial – Pages 13, 14, 16, and 17
- Industrial – Pages 14 and 17
- Public Authority – Pages 15 and 18

As described above, page 19 of this Exhibit provides actual heating degree days for the most recent 30 year period.

National Fuel Gas Distribution Corporation
Pennsylvania Division
Projected Volumes in Mcf
Shrinkage

2025

74 DD
Base Case
Peak Day
Jan 2025

Retail Sales	
Residential	220,297
Commercial	39,720
Industrial	2,644
Public Authority	3,335
Subtotal Retail Sales	265,996
Company Use	74
Total Retail Sales	266,070
Retail Sales Shrinkage	400
Total Retail Sales Requirements	266,470

Transportation Service	
Residential MMT Transportation	1,554
Commercial MMT Transportation	43,984
Industrial MMT Transportation	25,170
Public Authority MMT Transportation	23,292
Total MMT Service	94,000
MMT Service Shrinkage	141
Total MMT Service Requirements	94,141

Residential SATC Transportation	21,237
Commercial SATC Transportation	2,875
Industrial SATC Transportation	294
Public Authority SATC Transportation	196
Total SATC Service	24,602
SATC Service Shrinkage	37
Total SATC Service Requirements	24,639

Residential DMT Transportation	0
Commercial DMT Transportation	4,216
Industrial DMT Transportation	57,955
Public Authority DMT Transportation	1,494
Total DMT Service	63,665
DMT Service Shrinkage	96
Total DMT Service Requirements	63,761
Total DMT Service Requirements (Dth - 1.05 Btu)	66,949

Residential Transportation Service	22,791
Commercial Transportation Service	51,075
Industrial Transportation Service	83,418
Public Authority Transportation Service	24,982
Total Transportation Service	182,266
Total Transportation Shrinkage	274
Total Transportation Requirements	182,540

Total Requirements	449,010

NATIONAL FUEL GAS DISTRIBUTION CORPORATION 2023 Master Estimate

DIVISION: PENNSYLVANIA

PEAK DAY USED FOR CAPACITY ALLOCATION

WINTER PERIOD

VOLUMES IN MCF

Shrinkage

FY 2025					
	0.15%				
	NOAA				
	2006 - 2020				
				BASE	BASE
JANUARY NORMAL DEGREE DAYS =	1,116			CASE	CASE
				2024	2024
				62	74
Retail Sales	Jan-25	Jul-25	Aug-25	DEG DAYS	DEG DAYS
Residential	3,488,870	324,328	324,328	186,270	220,297
Commercial	629,055	58,477	58,477	33,585	39,720
Industrial	55,532			2,644	2,644
Public Authority	52,822	4,910	4,910	2,820	3,335
Company Use	2,289			74	74
Total Retail Sales	4,228,568			225,393	266,070
Total Retail Sales Shrinkage	6,352			339	400
Total Retail Sales Requirements	4,234,920			225,732	266,470

NATIONAL FUEL GAS DISTRIBUTION CORPORATION 2023 Master Estimate

DIVISION: PENNSYLVANIA

PEAK DAY USED FOR CAPACITY ALLOCATION

WINTER PERIOD

VOLUMES IN MCF

Shrinkage

	FY 2025					
	0.15%					
	NOAA 2006 - 2020			BASE CASE 2024		BASE CASE 2024
JANUARY NORMAL DEGREE DAYS =	1,116			52 62	MMT SATC	74
Residential	Jan-25	Jul-25	Aug-25	DEG DAYS		DEG DAYS
Transportation Service						
Monthly Metered Transportation (MMT)						
Residential	23,436	2,179	2,179	1,061		1,480
Small Com/Pub Auth LL (<250 Mcf/Yr)	36	3	3	2		2
Small Com/Pub Auth UL (250-1,000 Mcf/Yr)	99	9	9	4		6
Large Commercial/Pub Authority	1,052	98	98	48		66
Residential MMT Service	24,623	2,289	2,289	1,115		1,554
Residential MMT Shrinkage	37	3	3	2		2
Residential MMT Requirements	24,660	2,292	2,292	1,117		1,556
Small Aggregation Transportation Customer (SATC)						
Residential SATC Service	336,324	31,265	31,265	17,956		21,236
Small Com/Pub Auth LL (<250 Mcf/Yr)	16	1	1	1		1
Residential SATC Service	336,340	31,266	31,266	17,957		21,237
Residential SATC Shrinkage	505	47	47	27		32
Residential SATC Requirements	336,845	31,313	31,313	17,984		21,269
Daily Metered Transportation (DMT)						
Residential DMT Service	0	0	0	0		0
Residential DMT Service	0	0	0	0		0
Residential DMT Shrinkage	0	0	0	0		0
Residential DMT Requirements	0	0	0	0		0
Summary:						
Residential Transportation Service	360,963	33,555	33,555	19,072		22,791
Residential Transportation Shrinkage	542	50	50	29		34
Residential Transportation Requirements	361,505	33,605	33,605	19,101		22,825

NATIONAL FUEL GAS DISTRIBUTION CORPORATION 2023 Master Estimate
DIVISION: PENNSYLVANIA
PEAK DAY USED FOR CAPACITY ALLOCATION
WINTER PERIOD
VOLUMES IN MCF

Shrinkage	FY 2025					
	0.15%					
	NOAA 2006 - 2020					
JANUARY NORMAL DEGREE DAYS =	1,116			BASE CASE 2024	BASE CASE 2024	
Commercial				52	MMT	
Transportation Service				62	SATC	74
	Jan-25	Jul-25	Aug-25	DEG DAYS		DEG DAYS
Monthly Metered Transportation (MMT)						
Residential Sales Service	267	25	25	12		17
Small Commercial LL (<250 Mcf/Yr)	27,960	2,599	2,599	1,266		1,765
Small Commercial UL (250-1,000 Mcf/Yr)	127,161	11,821	11,821	5,756		8,029
Large Commercial (>1,000 Mcf/Yr)	541,193	50,310	50,310	24,496		34,173
Commercial MMT Service	696,581	64,755	64,755	31,530		43,984
Commercial MMT Shrinkage	1,046	97	97	47		66
Commercial MMT Requirements	697,627	64,852	64,852	31,577		44,050
Small Aggregation Transportation Customer (SATC)						
Residential Sales Service	0	0	0	0		0
Small Commercial LL (<250 Mcf/Yr)	14,316	1,331	1,331	764		904
Small Commercial UL (250-1,000 Mcf/Yr)	23,559	2,190	2,190	1,258		1,488
Large Commercial (>1,000 Mcf/Yr)	7,648	711	711	408		483
Commercial SATC Service	45,523	4,232	4,232	2,430		2,875
Commercial SATC Shrinkage	68	6	6	4		4
Commercial SATC Requirements	45,591	4,238	4,238	2,434		2,879
Daily Metered Transportation (DMT)						
Large Commercial (>1,000 Mcf/Yr) DMT	89,163	49,509	50,151	3,793		4,216
Commercial DMT Service	89,163	49,509	50,151	3,793		4,216
Commercial DMT Shrinkage	134	74	75	6		6
Commercial DMT Requirements	89,297	49,583	50,226	3,799		4,222
Summary:						
Commercial Transportation	831,267	118,495	119,138	37,753		51,075
Commercial Transportation Shrinkage	1,248	177	178	57		76
Commercial Transportation Requirements	832,515	118,672	119,316	37,810		51,151

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
DIVISION: PENNSYLVANIA
PEAK DAY USED FOR CAPACITY ALLOCATION
WINTER PERIOD
VOLUMES IN MCF
Shrinkage

2023 Master Estimate

	FY 2025		
	0.15%	BASE CASE 2024 62 SATC DEG DAYS	BASE CASE 2024 74 DEG DAYS
Industrial			
Transportation Service	Jan-25		
Monthly Metered Transportation (MMT)			
Small Volume Industrial Service-SVIS	7,402	239	352
Intermediate Volume Industrial Service-IVIS	445,267	14,363	21,203
Large Volume Industrial Service -LVIS	63,460	2,047	2,613
Large Volume Industrial Service -LVIS Load Balancing	0	0	0
Large Volume Industrial Service -LVIS	63,460	2,047	2,613
Large Industrial Service -LIS	32,185	1,038	1,002
Industrial Monthly Metered Transportation MMT Service	548,313	17,687	25,170
Industrial MMT Shrinkage	824	27	38
Industrial MMT Service Requirements	549,137	17,714	25,208
Small Aggregation Transportation Customer (SATC)			
Small Volume Industrial Service-SVIS	1,183	38	56
Intermediate Volume Industrial Service (IVIS)	2,255	73	238
Industrial SATC	3,437	111	294
Industrial SATC Shrinkage	5	0	0
Industrial SATC Requirements	3,442	111	294
Daily Metered Transportation (DMT)			
Intermediate Volume Industrial Service-IVIS	83,356	2,689	7,449
Large Volume Industrial Service -LVIS			
LVIS Daily Metered	257,054	8,292	7,112
LVIS Daily Metered Flex	0	0	0
LVIS Daily Metered Transportation	257,054	8,292	7,112
Large Industrial Service -LIS			
LIS Daily Metered	534,054	17,228	32,723
LIS Daily Metered Flex Rate	513,007	16,549	4,653
LIS Daily Metered Transportation	1,047,061	33,777	37,376
Daily Metered Large Manufacturing Transportation Service - DMLMTS	202,148	6,521	6,018
Industrial DMT Service	1,589,618	51,279	57,955
Industrial DMT Shrinkage	2,388	77	87
Industrial DMT Requirements	1,592,006	51,356	58,042
Summary:			
Industrial Transportation	2,141,369	69,077	83,418
Industrial Transportation Shrinkage	3,217	104	125
Industrial Transportation Requirements	2,144,586	69,181	83,543

NATIONAL FUEL GAS DISTRIBUTION CORPORATION 2023 Master Estimate

DIVISION: PENNSYLVANIA

PEAK DAY USED FOR CAPACITY ALLOCATION

WINTER PERIOD

VOLUMES IN MCF

Shrinkage

FY 2025						
	0.15%					
	NOAA					
	2006 - 2020					
JANUARY NORMAL DEGREE DAYS =	1,116			BASE CASE 2024	BASE CASE 2024	
				52	MMT	
Public Authority				62	SATC	74
Transportation Service	Jan-25	Jul-25	Aug-25	DEG DAYS		DEG DAYS
Monthly Metered Transportation (MMT)						
Small Public Auth-LL (< 250 Mcf/Yr)	3,569	332	332	162		225
Small Public Auth-UL (250-1,000 Mcf/Yr)	13,939	1,296	1,296	631		880
Large Public Auth (>1,000 Mcf/Yr)	351,373	32,664	32,664	15,904		22,187
Public Authority MMT Service	368,881	34,292	34,292	16,697		23,292
Public Authority MMT Shrinkage	554	52	52	25		35
Public Authority MMT Requirements	369,435	34,344	34,344	16,722		23,327
Small Aggregation Transportation Customer (SATC)						
Small Public Auth-LL (< 250 Mcf/Yr)	979	91	91	52		62
Small Public Auth-UL (250-1,000 Mcf/Yr)	1,658	154	154	89		105
Large Public Authority (>1,000 Mcf/Yr)	456	42	42	24		29
Public Authority SATC Service	3,093	288	288	165		196
Public Authority SATC Shrinkage	5	0	0	0		0
Public Authority SATC Requirements	3,098	288	288	165		196
Daily Metered Transportation (DMT)						
Large Public Authority DMT Service	26,868	8,440	8,449	1,296		1,494
Large Public Authority DMT Service	26,868	8,440	8,449	1,296		1,494
Public Authority DMT Shrinkage	40	13	13	2		2
Public Authority DMT Requirements	26,908	8,453	8,462	1,298		1,496
Summary:						
Public Authority Transportation	398,842	43,019	43,028	18,158		24,982
Public Authority Transportation Shrinkage	599	65	65	27		37
Public Authority Transportation Requirements	399,441	43,084	43,093	18,185		25,019

National Fuel Gas Distribution Corporation
Pennsylvania Division
Projected Gas Requirements - Calendar Month
Volumes in Mcf

	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Total
Retail Sales													
Residential	1,685,786	2,545,976	3,488,870	3,002,738	2,595,706	1,531,550	933,344	360,365	324,328	324,328	324,328	909,982	18,027,300
Commercial	303,953	459,048	629,055	541,404	468,014	276,143	168,285	64,975	58,477	58,477	58,477	164,842	3,251,151
Industrial	26,833	40,524	55,532	47,795	41,316	24,378	14,856	5,736	5,162	5,162	5,162	14,849	287,306
Public Authority	25,523	38,546	52,822	45,462	39,299	23,188	14,131	5,456	4,910	4,910	4,910	14,081	273,239
Subtotal Retail Sales	2,042,094	3,084,094	4,226,279	3,637,398	3,144,336	1,855,258	1,130,616	436,531	392,878	392,878	392,878	1,103,754	21,838,995
Company Use	836	836	1,910	2,289	2,163	1,997	1,385	947	236	70	62	836	13,567
Total Retail Sales	2,042,930	3,084,930	4,228,189	3,639,687	3,146,499	1,857,255	1,132,001	437,478	393,114	392,948	392,940	1,104,590	21,852,562
Retail Sales Shrinkage	3,069	4,634	6,352	5,468	4,727	2,790	1,701	657	591	590	590	1,659	32,828
Total Retail Sales Requirements	2,045,999	3,089,564	4,234,541	3,645,155	3,151,226	1,860,045	1,133,702	438,135	393,705	393,538	393,530	1,106,249	21,885,390
Transportation Service													
Residential MMT Transportation	11,897	17,968	24,623	21,192	18,319	10,809	6,587	2,543	2,289	2,289	2,289	6,484	127,289
Commercial MMT Transportation	336,581	508,325	696,581	599,521	518,254	305,786	186,350	71,950	64,755	64,755	64,755	182,357	3,599,970
Industrial MMT Transportation	300,658	415,668	548,313	480,279	425,832	281,079	204,656	128,286	125,252	132,954	131,502	210,463	3,384,942
Public Authority MMT Transportation	178,240	269,188	368,881	317,482	274,446	161,932	98,683	38,102	34,292	34,292	34,292	95,390	1,905,219
Total MMT Service	827,376	1,211,150	1,638,398	1,418,474	1,236,852	759,606	496,276	240,880	226,587	234,289	232,837	494,694	9,017,420
MMT Service Shrinkage	1,243	1,819	2,461	2,131	1,858	1,141	746	362	340	352	350	743	13,546
Total MMT Service Requirements	828,619	1,212,969	1,640,859	1,420,605	1,238,710	760,747	497,022	241,242	226,927	234,641	233,187	495,437	9,030,966
Residential SATC Transportation	162,516	245,442	336,340	289,475	250,236	147,647	89,978	34,741	31,266	31,266	31,266	83,560	1,733,734
Commercial SATC Transportation	21,996	33,220	45,523	39,180	33,869	19,984	12,178	4,702	4,232	4,232	4,232	9,895	233,242
Industrial SATC Transportation	2,379	3,363	3,437	3,081	2,499	1,603	724	399	390	431	631	1,293	20,230
Public Authority SATC Transportation	1,494	2,257	3,093	2,662	2,301	1,358	827	319	288	288	288	755	15,929
Total SATC Service	188,386	284,282	388,393	334,398	288,904	170,592	103,707	40,161	36,176	36,217	36,417	95,504	2,003,136
SATC Service Shrinkage													0
Total SATC Service Requirements	188,386	284,282	388,393	334,398	288,904	170,592	103,707	40,161	36,176	36,217	36,417	95,504	2,003,136
Residential DMT Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial DMT Transportation	61,311	73,254	80,070	89,163	80,629	80,175	69,315	59,606	51,274	49,509	50,151	62,601	807,058
Industrial DMT Transportation	1,179,029	1,328,546	1,575,121	1,589,618	1,430,272	1,393,386	1,231,557	1,104,793	1,084,843	1,170,876	1,221,528	1,274,365	15,583,934
Public Authority DMT Transportation	15,321	21,533	26,303	26,868	24,530	24,279	18,196	8,368	8,611	8,440	8,449	15,321	206,219
Total DMT Service	1,255,661	1,423,333	1,681,494	1,705,649	1,535,431	1,497,841	1,319,068	1,172,766	1,144,728	1,228,825	1,280,128	1,352,287	16,597,211
DMT Service Shrinkage	1,886	2,138	2,526	2,562	2,307	2,250	1,982	1,762	1,720	1,846	1,923	2,031	24,933
Total DMT Service Requirements	1,257,547	1,425,471	1,684,020	1,708,211	1,537,738	1,500,091	1,321,050	1,174,528	1,146,448	1,230,671	1,282,051	1,354,318	16,622,144
Residential Transportation Service	174,413	263,410	360,963	310,667	268,555	158,456	96,565	37,284	33,555	33,555	33,555	90,045	1,861,024
Commercial Transportation Service	419,888	614,799	822,174	727,864	632,752	405,945	267,843	136,257	120,261	118,495	119,138	254,853	4,640,270
Industrial Transportation Service	1,482,067	1,747,578	2,126,872	2,072,978	1,858,602	1,676,068	1,436,936	1,233,477	1,210,484	1,304,261	1,353,661	1,486,121	18,989,105
Public Authority Transportation Service	195,055	292,978	398,277	347,012	301,277	187,569	117,707	46,789	43,190	43,019	43,028	111,466	2,127,368
Total Transportation Service	2,271,423	2,918,764	3,708,286	3,458,521	3,061,187	2,428,039	1,919,051	1,453,807	1,407,490	1,499,331	1,549,382	1,942,485	27,617,766
Total Transportation Shrinkage	3,412	4,385	5,571	5,196	4,599	3,648	2,883	2,184	2,114	2,252	2,328	2,918	41,490
Total Transportation Requirements	4,546,258	5,841,914	7,422,142	6,922,238	6,126,973	4,859,725	3,840,984	2,909,799	2,817,095	3,000,914	3,101,093	3,887,888	27,659,256
Total Requirements	4,320,551	6,012,286	7,947,813	7,108,369	6,216,578	4,291,475	3,055,481	1,894,067	1,803,256	1,895,067	1,945,186	3,051,508	49,544,647

**National Fuel Gas Distribution Corporation
Pennsylvania Division
Projected Retail Gas Requirements - Calendar Month
Volumes in Mcf**

	WINTER PERIOD - CALENDAR MONTH					
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Total
Retail Sales						
Residential	1,685,786	2,545,976	3,488,870	3,002,738	2,595,706	13,319,075
Commercial	303,953	459,048	629,055	541,404	468,014	2,401,473
Industrial	26,833	40,524	55,532	47,795	41,316	212,000
Public Authority	25,523	38,546	52,822	45,462	39,299	201,652
Subtotal Retail Sales	2,042,094	3,084,094	4,226,279	3,637,398	3,144,336	16,134,201
Company Use	836	836	1,910	2,289	2,163	8,034
Total Retail Sales	2,042,930	3,084,930	4,228,189	3,639,687	3,146,499	16,142,235
Subtotal Retail Sales Shrinkage	3,069	4,634	6,352	5,468	4,727	24,250
Total Retail Sales Requirements	2,045,999	3,089,564	4,234,541	3,645,155	3,151,226	16,166,485

NFGDC - Pennsylvania Division
Volumes in Mcf
Consumption Month: January 2025

LVIS CUSTOMERS	Hours/Day	Days/Week	JANUARY 2025					2025 PEAK DAY				
			MMT	MMT Flex	DMT	DMT Flex	TOTAL	MMT	MMT Flex	DMT	DMT Flex	TOTAL
1	24.00	7.00			9,744		9,744			314		314
2	24.00	7.00	6,344				6,344	205				205
3	24.00	7.00			9,340		9,340			301		301
4	20.00	5.00			12,069		12,069			654		654
5	24.00	5.00			7,669		7,669			346		346
6	24.00	7.00			8,884		8,884			287		287
7	24.00	7.00			5,774		5,774			186		186
8	24.00	6.00			15,632		15,632			588		588
9	24.00	7.00			10,212		10,212			329		329
10	24.00	7.00			16,300		16,300			526		526
11	24.00	7.00	4,922				4,922	159				159
12	24.00	7.00			18,430		18,430			595		595
13	24.00	5.00			7,085		7,085			320		320
14	24.00	7.00			15,592		15,592			503		503
15	24.00	7.00			12,423		12,423			401		401
16	24.00	7.00			8,025		8,025			259		259
17	24.00	7.00			11,145		11,145			360		360
18	24.00	7.00		4,991			4,991		161			161
19	24.00	7.00			13,649		13,649			440		440
20	24.00	7.00			3,935		3,935			127		127
21	8.00	5.00	9,094				9,094	1,232				1,232
22	24.00	7.00	8,156				8,156	263				263
23	24.00	6.00	10,291				10,291	387				387
24	16.00	5.00			8,502		8,502			576		576
25	0.00	0.00	0				0	0				0
26	24.00	7.00	6,392				6,392	206				206
			45,199	4,991	194,409	0	244,599	2,452	161	7,112	0	9,725

*Note: The peak day forecast for Customer 18 is based on a bypass agreement with the customer.

NFGDC - Pennsylvania Division
Volumes in Mcf
Consumption Month: January 2025

			JANUARY 2025					2025 PEAK DAY				
LIS CUSTOMERS	Hours/Day	Days/Week	MMT	MMT Flex	DMT	DMT Flex	TOTAL	MMT	MMT Flex	DMT	DMT Flex	TOTAL
1	20.00	6.00			24,048		24,048			1,086		1,086
2	24.00	6.00			53,961		53,961			2,031		2,031
3	24.00	7.00			14,559		14,559			470		470
4	24.00	6.00			24,685		24,685			929		929
5	24.00	5.00			22,745		22,745			1,027		1,027
6	24.00	7.00			37,455		37,455			1,208		1,208
7	24.00	6.00			45,110		45,110			1,698		1,698
8	24.00	7.00			21,623		21,623			698		698
9	24.00	7.00			111,428		111,428			3,594		3,594
10	24.00	5.00			29,244		29,244			1,321		1,321
11	24.00	7.00			113,000		113,000			3,645		3,645
12	24.00	7.00			34,935		34,935			1,127		1,127
13	24.00	7.00	31,050				31,050	1,002				1,002
14	24.00	7.00			122,975		122,975			3,967		3,967
15	24.00	7.00			92,306		92,306			2,978		2,978
16	24.00	7.00			215,294		215,294			6,945		6,945
17	24.00	7.00				64,236	64,236				2,072	2,072
18	24.00	7.00				80,000	80,000				2,581	2,581
Total LIS			31,050	0	963,365	144,236	1,138,651	1,002	0	32,723	4,653	38,377

			EXTREME PEAK DAY				
DMLMTS CUSTOMER	Hours/Day	Days/Week	MMT	MMT Flex	DMT	DMT Flex	TOTAL
1	24.00	7.00				186,545	186,545
Total DMLMTS			0	0	0	186,545	186,545

			EXTREME PEAK DAY				
DMLMTS CUSTOMER	Hours/Day	Days/Week	MMT	MMT Flex	DMT	DMT Flex	TOTAL
1	24.00	7.00				6,018	6,018
Total DMLMTS			0	0	0	6,018	6,018

MCF/Account Forecasting - Regression Results

Residential Retail & Transportation (Non Res E)

Normal MCF/Acct - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.99088377
R Square	0.98185065
Adjusted R Square	0.95154762
Standard Error	359.069847
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	230173926	230173926	1785.24675	1.20609E-29
Residual	33	4254728.123	128931.155		
Total	34	234428654.1			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	1.28391687	0.030386997	42.2521804	2.5963E-30	1.222094064	1.34573968	1.222094064	1.345739684

Residential Retail & Transportation (Res E & LIRA)

Normal MCF/Acct - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.99963768
R Square	0.99927549
Adjusted R Square	0.96897246
Standard Error	2.65309908
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	320375.5796	320375.58	45514.7821	4.93393E-52
Residual	33	232.2848453	7.03893471		
Total	34	320607.8645			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	0.04790033	0.000224524	213.341937	2.1395E-53	0.047443538	0.04835713	0.047443538	0.048357132

Commercial Retail & Transportation SM

Normal MCF/Acct - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.99871953
R Square	0.9974407
Adjusted R Square	0.96713767
Standard Error	11.8459417
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	1804760.223	1804760.22	12861.1655	2.90487E-43
Residual	33	4630.769077	140.326336		
Total	34	1809390.992			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	0.11368904	0.001002486	113.407079	2.3654E-44	0.111649466	0.11572861	0.111649466	0.115728614

Commercial Retail & Transportation LG

Normal MCF/Acct - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.99935792
R Square	0.99871625
Adjusted R Square	0.96841322
Standard Error	108.555595
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	302539134.4	302539134	25673.0304	4.65947E-48
Residual	33	388882.4679	11784.3172		
Total	34	302928016.9			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	1.47197226	0.009186732	160.228058	2.6888E-49	1.453281708	1.4906628	1.453281708	1.490662802

Industrial Retail & Transportation

Normal MCF/Acct - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.99748341
R Square	0.99497315
Adjusted R Square	0.96467012
Standard Error	365.943638
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	874697577.1	874697577	6531.74952	1.42869E-38
Residual	33	4419186.616	133914.746		
Total	34	879116763.7			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	2.50286719	0.030968705	80.8192398	1.6286E-39	2.43986089	2.5658735	2.43986089	2.565873498

Public Authority Transportation - SM

Normal MCF/Acct - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.99913121
R Square	0.99826318
Adjusted R Square	0.96796015
Standard Error	11.0535739
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	2317450.523	2317450.52	18967.279	5.87385E-46
Residual	33	4031.989361	122.181496		
Total	34	2321482.512			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	0.12882913	0.000935431	137.721745	3.9418E-47	0.126925984	0.13073228	0.126925984	0.130732279

Public Authority Retail & Transportation - LG

Normal MCF/Acct - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.99740304
R Square	0.99481282
Adjusted R Square	0.96450979
Standard Error	440.356873
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	1227252094	1227252094	6328.84156	2.3614E-38
Residual	33	6399167.801	193914.176		
Total	34	1233651262			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	2.96466574	0.037266072	79.5540166	2.7341E-39	2.888847348	3.04048414	2.888847348	3.040484137

Account Forecasting - Regression Results

Residential Retail & Transportation (Non Res E)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.968671
R Square	0.938323
Adjusted R Square	0.90802
Standard Error	17.81909
Observations	34

ANOVA

	df	SS	MS	F	Significance F
Regression	1	159409.7	159409.7	502.0463169	3.97847E-21
Residual	33	10478.16	317.5199		
Total	34	169887.9			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	0.033788	0.001508	22.40639	1.54678E-21	0.030720292	0.036856	0.03072	0.036856

Residential Retail & Transportation (Res E & LIRA)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.999277
R Square	0.998554
Adjusted R Square	0.968251
Standard Error	7493.554
Observations	34

ANOVA

	df	SS	MS	F	Significance F
Regression	1	1.28E+12	1.28E+12	22783.91159	3.13945E-47
Residual	33	1.85E+09	56153354		
Total	34	1.28E+12			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	95.7218	0.634157	150.9434	1.92279E-48	94.43159419	97.012	94.43159	97.012

Commercial Retail & Transportation SM

Total Customers - Regression

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.999211
R Square	0.998423
Adjusted R Square	0.96812
Standard Error	559.9862
Observations	34

ANOVA

	df	SS	MS	F	Significance F
Regression	1	6.55E+09	6.55E+09	20894.83372	1.25149E-46
Residual	33	10348291	313584.6		
Total	34	6.56E+09			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	6.850238	0.04739	144.5505	8.00287E-48	6.753822111	6.946653	6.753822	6.946653

Commercial Retail & Transportation LG

Normal MCF/Acct - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.999437
R Square	0.998874
Adjusted R Square	0.968571
Standard Error	41.24015
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	49802703	49802703	29282.79574	5.69122E-49
Residual	33	56124.74	1700.75		
Total	34	49858828			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	0.597221	0.00349	171.1222	3.07557E-50	0.590120799	0.604322	0.590121	0.604322

Industrial Retail & Transportation

Total Customers - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.999896
R Square	0.999792
Adjusted R Square	0.969489
Standard Error	7.667121
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	9326067	9326067	158647.7425	1.0473E-60
Residual	33	1939.897	58.78474		
Total	34	9328007			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	0.258439	0.000649	398.3061	2.4337E-62	0.257118945	0.259759	0.257119	0.259759

Public Authority Transportation - SM

Total Customers - Regression

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.99977
R Square	0.99954
Adjusted R Square	0.969237
Standard Error	19.25539
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	26576216	26576216	71678.43057	3.46056E-55
Residual	33	12235.41	370.7701		
Total	34	26588452			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	0.43627	0.00163	267.7283	1.19608E-56	0.432954774	0.439585	0.432955	0.439585

Public Authority Retail & Transportation - LG

SUMMARY OUTPUT

<i>Regression Statistics</i>	
Multiple R	0.996905
R Square	0.993819
Adjusted R Square	0.963516
Standard Error	27.47315
Observations	34

ANOVA

	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>
Regression	1	4004583	4004583	5305.669441	3.90818E-37
Residual	33	24907.55	754.7742		
Total	34	4029490			

	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2009	0.169351	0.002325	72.84003	4.93739E-38	0.164620697	0.174081	0.164621	0.174081

**National Fuel Gas Distribution Corporation
Pennsylvania Division
Heating Degree Days**

YEAR	NOV - MAR HEATING SEASON	HEATING DEGREE DAYS	MEAN TEMPERATURE
1	1993 - 1994	76	-11
2	1994 - 1995	57	8
3	1995 - 1996	64	1
4	1996 - 1997	61	4
5	1997 - 1998	45	20
6	1998 - 1999	56	9
7	1999 - 2000	54	11
8	2000 - 2001	53	12
9	2001 - 2002	47	18
10	2002 - 2003	59	6
11	2003 - 2004	58	7
12	2004 - 2005	62	3
13	2005 - 2006	50	15
14	2006 - 2007	60	5
15	2007 - 2008	56	9
16	2008 - 2009	64	1
17	2009 - 2010	55	10
18	2010 - 2011	59	6
19	2011 - 2012	51	14
20	2012 - 2013	54	11
21	2013 - 2014	68	-3
22	2014 - 2015	71	-6
23	2015 - 2016	54	11
24	2016 - 2017	52	13
25	2017 - 2018	58	7
26	2018 - 2019	63	2
27	2019 - 2020	51	14
28	2020 - 2021	49	16
29	2021 - 2022	56	9
30	2022 - 2023	59	6

National Fuel Gas Distribution Corporation
Pennsylvania Division

53.64 (c) (14) – Historic and Future Minimum Gas Entitlements

Analysis and data demonstrating on a historic and projected future basis the minimum gas entitlements needed to provide reliable and uninterrupted service to priority one customers during peak periods.

As defined in National Fuel Gas Distribution Corporation's ("Distribution" or the "Company") Tariff, the Priority 1 category is composed of residential and firm critical commercial and public authority essential human needs customers. Essential human needs use includes any buildings where persons normally dwell, including but not limited to: apartment houses, dormitories, hotels, hospitals and nursing homes. It also includes use from natural gas sewage plants.

Page 2 shows by North American Industry Classification System ("NAICS") code, volumes for January 2023 for commercial and public authority Priority 1 customers. December 23, 2022 is the most recent historic peak day experienced since it was the day with the greatest gas usage, as described in greater detail in Exhibit 14. The average temperature for December 23, 2022 was 20 degrees Fahrenheit or 45 degree days (on a midnight to midnight basis). Historical residential peak day usage (181,715 Mcf) was calculated using the same methodology described in Exhibit 14. Historical commercial and public authority Priority 1 peak day usage (23,770 Mcf) was calculated by allocating commercial/public authority Priority 1 service on a monthly basis (25.23%) to the commercial/public authority peak day.

The peak day gas supply that was needed to meet the January 2023 peak day, as well as the projected peak day gas supply that will be needed for priority 1 customers, is shown below. It should be noted that the projection for January 2025 is based on the peak day calculation presented in Exhibit 15.

	Historic Jan 2023	Future Jan 2025
Residential	181,715	243,088
Commercial	<u>23,770</u>	<u>30,052</u>
Total	205,485 Mcf	273,140 Mcf

National Fuel Gas Distribution Corporation
Pennsylvania Division
Priority One Categories by NAICS Code
January 2023 Volumes in Mcf

NAICS	CATEGORY NAME	CUST	MCF
221310	Water Supply and Irrigation Systems	49	6879.8
221320	Sewage Treatment Facilities	49	12496.2
531110	Lessors of Residential Buildings and Dwellings	723	54418.4
562211	Hazardous Waste Treatment and Disposal	12	622.5
562212	Solid Waste Landfill	2	349.5
562213	Solid Waste Combustors and Incinerators	1	526
562920	Materials Recovery Facilities	2	71.4
621492	Kidney Dialysis Centers	8	470.4
621610	Home Health Care Services	28	548.8
622110	General Medical and Surgical Hospitals	110	111343.6
622210	Psychiatric and Substance Abuse Hospitals	13	507
622310	Specialty (except Psychiatric and Substance Abuse) Hospitals	5	2523.1
623110	Nursing Care Facilities (Skilled Nursing Facilities)	136	36642.6
623210	Residential Intellectual and Developmental Disabilities Facilities	60	2228.9
623220	Residential Mental Health and Substance Abuse Facilities	11	2035
623311	Continuing Care Retirement Communities	5	4945.4
623312	Assisted Living Facilities for the Elderly	14	3929.5
623990	Other Residential Care Facilities	15	1327.7
721110	Hotels (except Casino Hotels) and Motels	160	15705.1
721191	Bed-and-Breakfast Inns	3	115.9
721211	RV (Recreational Vehicle) Parks and Campgrounds	16	328.4
721214	Recreational and Vacation Camps (except Campgrounds)	10	1106.4
721310	Rooming and Boarding Houses	15	27778.9
813110	Religious Organizations	427	45616.4
922120	Police Protection	24	1650.1
922140	Correctional Institutions	16	25783.4
922160	Fire Protection	162	9201.5
		2,076	369,152

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

53.65 (1) Whenever a Section 1307(f) gas utility purchases gas, transportation or storage from an affiliated interest... it must ... file evidence to meet its burden pursuant to 66 Pa. C.S. Section 1317 (b). Such evidence ... shall include:

- (a) The costs of the affiliated gas, transportation or storage as compared to the average market price of other gas, transportation or storage and the price of other sources of gas, transportation or storage.

Attached hereto on pages 2 and 3 is the calculation of the average price charged by each of the upstream pipeline companies providing transportation or storage service to Distribution's Pennsylvania Division. Page 2 compares the average transportation cost by pipeline to Distribution's Pennsylvania Division for the timeframe December 2022 through November 2023. It is noted that services provided by the pipelines are not interchangeable. Some provide long distance transportation from distant sources of supply. Others provide services that are more regional in nature. National Fuel Gas Supply Corporation provides transportation services that connect the Company's numerous local distribution systems to long line interstate pipelines and local sources of supply. Page 3 shows the average storage rental cost to Distribution's Pennsylvania Division for the timeframe December 2022 through November 2023. Like transportation, storage services are not interchangeable. Some services are peaking services that cannot be used to meet seasonal demand. Other services do not have adequate capacity to meet Distribution's requirements or would require Distribution to incur additional charges for transportation services.

National Fuel Gas Distribution Corporation
Pennsylvania Division
Upstream Transportation Cost
Twelve Months Ended November 2023

PGC Exhibit 17
Page 2

<u>Pipeline</u>	<u>Demand</u> (\$)	<u>Amount</u> <u>Commodity</u> (\$)	<u>Total</u> (\$)	<u>Volume</u> (Mcf)	<u>Unit Cost</u> (\$/Mcf)
Columbia	\$1,857,659	\$28,406	\$1,886,065	1,994,773	\$ 0.9455
Dominion	\$0	\$0	\$0	0	\$0.0000
Tennessee	\$5,984,848	\$367,394	\$6,352,242	7,719,201	\$ 0.8229
Texas Eastern	\$595,620	\$161,200	\$756,819	3,232,594	\$ 0.2341
Gross Total (Non-Affiliated)	\$8,438,127	\$557,000	\$8,995,126	12,946,568	\$0.6948
NFGSC (Affiliated)	\$23,154,087	\$319,440	\$23,473,528	17,280,685	\$1.3584

National Fuel Gas Distribution Corporation
Pennsylvania Division
Upstream Storage Rental Cost
Twelve Months Ended November 2023

PGC Exhibit 17
Page 3

<u>Pipeline</u>	<u>Demand</u> (<u>\$</u>)	<u>Amount</u> <u>Commodity</u> (<u>\$</u>)	<u>Total</u> (<u>\$</u>)	<u>Volume</u> (<u>Mcf</u>)	<u>Unit Cost</u> (<u>\$/Mcf</u>)
Columbia	\$943,716	\$13,695	\$957,412	1,503,621	\$0.6367
Gross Total (Non-Affiliated)	\$943,716	\$13,695	\$957,412	1,503,621	\$0.6367
NFGSC (Affiliated)	\$12,461,270	\$606,236	\$13,067,506	12,755,361	\$1.0245

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

53.65 Whenever a gas utility under 66 Pa. C.S. § 1307(f) (relating to sliding scale of rates; adjustments) purchases gas, transportation or storage from an affiliated interest ... it shall... file evidence to meet its burden under 66 Pa. C.S. § 1317(b) (relating to regulation of natural gas costs). The evidence ... shall include statements regarding:

- (2) Estimates of the quantity of gas, transportation or storage available to the utility from all sources.**

Distribution has contracted for transportation and storage capacity based on its geographic location, its interconnections with National Fuel Gas Supply Corporation ("Supply") and upstream pipelines that are accessible via Supply. The transportation and storage available to Distribution from Supply and other upstream pipelines are provided in PGC Exhibit No. 7.

Distribution primarily accesses gas supplies from the Northeast shale producing region, but with these pipelines it is possible for Distribution to access gas supplies from nearly any area of the United States and Canada.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

53.65 Whenever a gas utility under 66 Pa. C.S. § 1307(f) (relating to sliding scale of rates; adjustments) purchases gas, transportation, or storage from an affiliated interest ... it shall ... file evidence to meet its burden under 66 Pa. C.S. § 1317(b) (relating to regulation of natural gas costs). The evidence ... shall include statements regarding:

- (3) Efforts made by the utility to obtain gas, transportation, or storage from nonaffiliated sources.**
 - (4) The specific reasons why the utility has purchased gas, transportation, or storage from an affiliated interest and demonstration that the purchases are consistent with a least cost fuel procurement policy.**
- (3) PGC Exhibit No. 8 provides Distribution's efforts to obtain gas, transportation, or storage from non-affiliated sources.
 - (4) PGC Exhibit No. 8 provides the explanation of Distribution's historical purchasing policies as well as an explanation of the reason for the transportation and storage capacity purchased by Distribution from Supply.

Distribution made two automatic, non-discretionary purchases of monthly imbalance gas from National Fuel Resources, Inc. ("NFR"), its former affiliate, during the historical period ended November 30, 2023 (excluding November 2023 for which data is not yet available). These purchases represent prior period adjustments as NFR is no longer an active affiliate serving Distribution customers. These purchases totaled 568 Mcf of monthly surplus imbalance gas and were relative to Distribution's SATC and MMNGS services. These transactions with NFR were performed in the ordinary course of business under Distribution's tariff and in a non-discriminating manner.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

- 53.65** Whenever a gas utility under 66 Pa. C.S. § 1307(f) (relating to sliding scale of rates; adjustments) purchases gas, transportation, or storage from an affiliated interest ... it shall ... file evidence to meet its burden under 66 Pa. C.S. § 1317(b) (relating to regulation of natural gas costs). The evidence ... shall include statements regarding:
- (5) The sources and amounts of all gas, transportation or storage which have been withheld from the market by the utility or affiliated interest and the reasons why the gas, transportation or storage has been withheld.**

Distribution has not withheld any gas, transportation or storage from the market. As explained in PGC Exhibit No. 8, Distribution purchases gas from marketers and producers that originates primarily in the Northeast, as well as from local producers, and transports these purchases on its pipeline capacity to meet its customers' needs. Consistent with previous 1307(f) filings, Distribution does not consider gas it has contracted for but not taken due to operational or market conditions to be subject to this requirement.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division

Computation of Purchased Gas Commodity Cost Per Mcf
On and After August 1, 2024

Computation Year: Twelve Months Ended July 2025

<u>Line No.</u>	<u>Description</u>	
1	Purchased Gas Commodity Costs = $(CC - E) \div S$	
2	CC = Commodity Cost of Gas (Exhibit 3)	76,803,656
3	S = Projected Sales for the Computation Year (See Exhibit 22)	<u>21,817,752</u>
4	Unit Commodity Cost (Line 2 / Line 3)	3.5202
5	Storage Interest (Exhibit 21B, Sheet 2)	<u>(0.0129)</u>
6	Total Commodity Cost (Line 4 + Line 5)	3.5073
7	E = Experienced Net Overcollection to be Refunded (See Schedule 5 - COMMODITY)	4,277,608
8	S = Projected Sales for the Computation Year (See Exhibit 22)	21,817,752
9	Projected SATC Volumes for Computation Year	<u>0</u>
10	Total Volumes for Recovery of Commodity E - Factor (Line 8 + Line 9)	21,817,752
11	Unit Commodity E-Factor Rate (Line 7 / Line 10)	<u>0.1961</u>
12	Projected Sales Commodity Cost per Mcf (Line 6 - Line 11)	<u><u>3.3112</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Computation of Purchased Gas Demand Cost Per Mcf
On and After August 1, 2024

Computation Year: Twelve Months Ended July 2025

<u>Line No.</u>	<u>Description</u>	
1	Purchased Gas Demand Costs = DC ÷ S	
2	DC = Demand Cost of Gas - Natural Gas Supply (Exhibit 3)	44,207,399
3	Projected Sales for Computation Year (Exhibit 22)	<u>21,817,752</u>
4	Unit Demand Cost (Line 2 / Line 3)	<u>2.0262</u>
5	E = Experienced Net Undercollection to be Recovered (See Schedule 2 - DEMAND - NGS)	(3,233,172)
6	S = Projected Sales for the Computation Year (Exhibit 22)	<u>21,817,752</u>
7	Unit Demand E-Factor Rate (Line 5 / Line 6)	<u>(0.1482)</u>
8	Projected Sales Demand Cost per Mcf (Line 4 - Line 7)	<u><u>2.1744</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Computation of Purchased Gas Demand Cost Per Mcf
On and After August 1, 2024

Computation Year: Twelve Months Ended July 2025

<u>Line No.</u>	<u>Description</u>	
1	Purchased Gas Demand Costs = DC ÷ S	
2	DC = Demand Cost of Gas - Distribution Charge (Exhibit 3)	10,519,956
3	Projected Sales for Computation Year (Exhibit 22)	21,817,752
4	Projected SATC Volumes for Computation Year	<u>2,012,390</u>
5	Total Volumes for Recovery of Demand Costs - Distribution Charge	23,830,142
6	Unit Demand Cost (Line 2 / Line 5)	<u>0.4415</u>
7	E = Experienced Net Undercollection to be Recovered (See Schedule 2 - DEMAND - DC)	(24,052)
8	Total Volumes for Recovery of Demand Costs - Distribution Charge	23,830,142
9	Unit Demand E-Factor Rate	<u>(0.0010)</u>
10	Projected Sales Demand Cost per Mcf (Line 6 - Line 9)	<u><u>0.4425</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Pennsylvania Division
Recovery of Gas Costs Under 2024 1307(f)

	(1)	(2)	(3)	(4)
	Natural Gas Supply <u>Charge</u>	Gas Adjustment <u>Charge</u>	Distribution <u>Charge</u>	Total <u>Gas Costs</u>
	(\$)	(\$)	(\$)	(\$)
Projected Gas Costs				
Demand	2.0262	0.1482	0.4425	2.6169
Commodity	<u>3.5073</u>	<u>(0.1961)</u>	<u>0.0000</u>	<u>3.3112</u>
Total Projected Gas Costs	5.5335	(0.0479)	0.4425	5.9281
Current Gas Costs (11/23)	<u>4.6076</u>	<u>(1.1113)</u>	<u>0.3794</u>	<u>3.8757</u>
Increase / (Decrease)	<u>0.9259</u>	<u>1.0634</u>	<u>0.0631</u>	<u>2.0524</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Statement Showing the Development of Experienced Net
Over / (Under) Collections

<u>Line No.</u>	<u>Description</u>	<u>Amount</u> \$
1	Estimated Undercollection of gas cost for the twelve month period	
2	August 2023 through July 2024 to be Recovered (Schedule 3)	(3,120,172)
3	Reconciliation of estimated Undercollection of gas cost for the	
4	twelve month period August 2022 through July 2023 (Schedule 7)	0
5	Reconciliation of Overcollection of gas cost balances for the	
6	twelve month period August 2021 through July 2022	
7	(Schedule 8, Sheet 1)	0
8	Estimated Undercollection of gas cost for the	
9	twelve month period August 2022 through July 2023	
10	to be Recovered for the twelve months ended July 2024 (Schedule 8, Sheet 2)	(112,637)
11	Reconciliation of refund balances for the twelve month period	0
12	August 2021 - July 2022 (Schedule 9, Sheet 1)	
13	Estimated balance of refunds / (surcharges) for the twelve month period	(363)
14	August 2022 - July 2023 (Schedule 9, Sheet 2)	
15	Refunds Received and included in PGC 2024 (Schedule 4)	<u>0</u>
16	Total Amount to be Recovered	<u><u>(3,233,172)</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Statement Showing the Development of Experienced Net
Over / (Under) Collections

<u>Line No.</u>	<u>Description</u>	<u>Amount</u> \$
1	Estimated Undercollection of gas cost for the twelve month period	
2	August 2023 through July 2024 to be Recovered (Schedule 3)	(32,380)
3	Reconciliation of estimated Undercollection of gas cost for the	
4	twelve month period August 2022 through July 2023 (Schedule 7)	0
5	Reconciliation of estimated Undercollection of gas cost balances for the	
6	twelve month period August 2021 through July 2022	
7	for the twelve months ended July 2023 (Schedule 8, Sheet 1)	0
8	Estimated Undercollection of gas cost for the	
9	twelve month period August 2022 through July 2023	
10	to be Recovered for the twelve months ended July 2024 (Schedule 8, Sheet 2)	(15,054)
11	Reconciliation of refund balances for the twelve month period	
12	August 2021 - July 2022 (Schedule 9, Sheet 1)	0
13	Estimated balance of refunds/surcharges for the twelve month period	
14	August 2022 - July 2023 (Schedule 9, Sheet 2)	<u>23,382</u>
15	Total Amount to be Recovered	<u><u>(24,052)</u></u>

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2024**

DEMAND - NGS

	<u>Sales</u>	PGC	PGC	Cost of	Over / (Under)	Interest	Interest	Interest
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
August (2023)								
Demand			404,702					
Standby / Priority			24,216					
Standby Overruns			391					
NGV - Demand			7,121					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			88,622					
			<u>525,052</u>	713,742	(188,691)	8.50%	18 / 12	(24,058)
September								
Demand			488,557					
Standby / Priority			27,647					
Standby Overruns			684					
NGV - Demand			7,587					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			82,896					
			<u>607,370</u>	303,844	303,526	8.50%	17 / 12	36,550
October								
Demand			810,447					
Standby / Priority			33,313					
Standby Overruns			2					
NGV - Demand			12,759					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			83,388					
			<u>939,909</u>	16,878	923,031	8.50%	16 / 12	104,610
November								
Demand			2,215,172					
Standby / Priority			63,466					
Standby Overruns			8,269					
NGV - Demand			1,214					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			93,690					
			<u>2,381,811</u>	4,839,367	(2,457,556)	8.50%	15 / 12	(261,115)

PGC Exhibit 21
Schedule 3
Sheet 1
DEMAND - NGS

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2024**

DEMAND - NGS

	<u>Sales</u> Mcf (1)	PGC <u>Rate</u> \$ / Mcf (2)	PGC <u>Revenue</u> \$ (3 = 1 x 2)	Cost of <u>Fuel</u> \$ (4)	Over / (Under) <u>Collections</u> \$ (5 = 3 - 4)	Interest <u>Rate</u> % (6)	Interest <u>Weight</u> (7)	Interest <u>Expense / (Income)</u> \$ (8 = 5 x 6 x 7)
December								
Demand	<u>2,799,328</u>	1.8440	<u>5,161,961</u>					
	2,799,328		5,161,961	5,018,437	143,524	8.50%	14 / 12	14,233
January (2024)								
Demand	<u>3,742,164</u>	1.8440	<u>6,900,551</u>					
	3,742,164		6,900,551	7,575,691	(675,140)	8.50%	13 / 12	(62,169)
February								
Demand	<u>3,909,889</u>	1.8440	<u>7,209,835</u>					
	3,909,889		7,209,835	7,972,586	(762,751)	8.50%	12 / 12	(64,834)
March								
Demand	<u>3,390,346</u>	1.8440	<u>6,251,798</u>					
	3,390,346		6,251,798	9,004,829	(2,753,031)	8.50%	11 / 12	(214,507)

PGC Exhibit 21
Schedule 3
Sheet 2
DEMAND - NGS

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2024**

DEMAND - NGS

		<u>Sales</u>	PGC	PGC	Cost of	Over / (Under)	Interest	Interest	Interest
		<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
		(1)	(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
April									
	Demand	<u>2,476,675</u>	1.8440	<u>4,566,989</u>					
		2,476,675		4,566,989	3,090,257	1,476,732	8.50%	10 / 12	104,602
May									
	Demand	<u>1,279,705</u>	1.8440	<u>2,359,776</u>					
		1,279,705		2,359,776	1,022,928	1,336,848	8.50%	9 / 12	85,224
June									
	Demand	<u>647,700</u>	1.8440	<u>1,194,359</u>					
		647,700		1,194,359	1,106,001	88,358	8.50%	8 / 12	5,007
July									
	Demand	<u>403,521</u>	1.8440	<u>744,093</u>					
		403,521		744,093	1,009,497	(265,404)	8.50%	7 / 12	(13,160)
	Total	18,649,329		38,843,504	41,674,058	(2,830,554)			(289,618)

PGC Exhibit 21
Schedule 3
Sheet 3
DEMAND - NGS

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2024**

DEMAND - DC

	<u>Sales</u> Mcf (1)	<u>PGC</u> <u>Rate</u> \$ / Mcf (2)	<u>PGC</u> <u>Revenue</u> \$ (3 = 1 x 2)	<u>Cost of</u> <u>Fuel</u> \$ (4)	<u>Over / (Under)</u> <u>Collections</u> \$ (5 = 3 - 4)	<u>Interest</u> <u>Rate</u> % (6)	<u>Interest</u> <u>Weight</u> (7)	<u>Interest</u> <u>Expense / (Income)</u> \$ (8 = 5 x 6 x 7)
August (2023)								
Distribution Charge			85,212					
SATC			8,576					
			<u>93,788</u>	582,040	(488,252)	8.50%	18 / 12	(62,252)
September								
Distribution Charge			97,326					
SATC			9,691					
			<u>107,017</u>	582,040	(475,023)	8.50%	17 / 12	(57,201)
October								
Distribution Charge			162,160					
SATC			16,169					
			<u>178,329</u>	582,040	(403,711)	8.50%	16 / 12	(45,754)
November								
Distribution Charge			438,048					
SATC			42,065					
			<u>480,113</u>	582,096	(101,983)	8.50%	15 / 12	(10,836)
December								
Distribution Charge	2,799,328	0.3794	1,062,159					
SATC	<u>271,116</u>	0.3794	<u>102,870</u>					
	3,070,444		1,165,029	538,517	626,512	8.50%	14 / 12	62,129
January (2024)								
Distribution Charge	3,742,164	0.3794	1,419,902					
SATC	<u>365,015</u>	0.3794	<u>138,499</u>					
	4,107,179		1,558,401	538,517	1,019,884	8.50%	13 / 12	93,914

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2024**

DEMAND - DC

		<u>Sales</u> Mcf (1)	<u>PGC</u> <u>Rate</u> \$ / Mcf (2)	<u>PGC</u> <u>Revenue</u> \$ (3 = 1 x 2)	<u>Cost of</u> <u>Fuel</u> \$ (4)	<u>Over / (Under)</u> <u>Collections</u> \$ (5 = 3 - 4)	<u>Interest</u> <u>Rate</u> % (6)	<u>Interest</u> <u>Weight</u> (7)		<u>Interest</u> <u>Expense / (Income)</u> \$ (8 = 5 x 6 x 7)
February										
	Distribution Charge	3,909,889	0.3794	1,483,543						
	SATC	379,905	0.3794	144,149						
		<u>4,289,793</u>		<u>1,627,692</u>	877,763	749,929	8.50%	12	/ 12	63,744
March										
	Distribution Charge	3,390,346	0.3794	1,286,411						
	SATC	339,513	0.3794	128,823						
		<u>3,729,859</u>		<u>1,415,234</u>	877,763	537,471	8.50%	11	/ 12	41,878
April										
	Distribution Charge	2,476,675	0.3794	939,734						
	SATC	250,667	0.3794	95,112						
		<u>2,727,342</u>		<u>1,034,846</u>	877,763	157,083	8.50%	10	/ 12	11,127
May										
	Distribution Charge	1,279,705	0.3794	485,563						
	SATC	132,354	0.3794	50,220						
		<u>1,412,059</u>		<u>535,783</u>	877,763	(341,980)	8.50%	9	/ 12	(21,801)
June										
	Distribution Charge	647,700	0.3794	245,759						
	SATC	64,592	0.3794	24,508						
		<u>712,292</u>		<u>270,267</u>	877,763	(607,496)	8.50%	8	/ 12	(34,425)
July										
	Distribution Charge	403,521	0.3794	153,109						
	SATC	38,287	0.3794	14,527						
		<u>441,807</u>		<u>167,636</u>	877,763	(710,127)	8.50%	7	/ 12	(35,210)
	Total	20,490,777		8,634,135	8,671,828	(37,693)				5,313

PGC Exhibit 2
Schedule 3
Sheet 2
DEMAND - DC

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Refunds From and Payments to Gas Suppliers

	<u>Refund From</u>	<u>Date Received</u>	<u>Refund Amount</u> \$	<u>INTEREST</u>			<u>Total Refund Plus Interest</u> \$
				<u>Rate</u>	<u>Weight</u>	<u>Amount</u> \$	
A.				0.00%	0 / 12	0	0
B.				0.00%	0 / 12	0	0
	TOTAL		<u>0</u>			<u>0</u>	<u>0</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Statement Showing the Development of Experienced Net
Over / (Under) Collections

<u>Line No.</u>	<u>Description</u>	<u>Amount</u> \$
1	Estimated Overcollection of gas cost for the twelve month period	
2	August 2023 through July 2024 to be Refunded (Schedule 6)	3,667,303
3	Reconciliation of estimated Overcollection of gas cost for the	
4	twelve month period August 2022 through July 2023 (Schedule 7)	0
5	Reconciliation of Undercollection of gas cost for the	
6	twelve month period August 2021 through July 2022	
7	(Schedule 8, Sheet 1)	0
8	Reconciliation of estimated Overcollection of gas cost for the	
9	twelve month period August 2021 through July 2022	
10	to be Refunded for the twelve months ended July 2023 (Schedule 8, Sheet 2)	608,620
11	Reconciliation of refunds for the twelve month period	
12	August 2021 - July 2022 (Schedule 9, Sheet 1)	0
13	Estimated balance of refunds for the twelve month period	
14	August 2022 - July 2023 (Schedule 9, Sheet 2)	0
15	Refunds Received and included in PGC 2024 (Schedule 10)	0
16	Reconciliation of C-Factor Storage Interest Expense / (Income) originating in	
17	PGC 2022 for the twelve months ended July 2022 (Schedule 11, Sheet 1)	0
18	Actual C-Factor Storage Interest Expense / (Income) originating in	
19	PGC 2023 for the twelve months ended July 2023 (Schedule 11, Sheet 2)	0
20	Reconciliation of Storage Interest refund balance for the period August 2022 - July 2023	
21	(recovered)/passed back August 2023 - July 2024 (Schedule 11, Sheet 3)	(9,320)
22	Estimated C-Factor Interest Expense / (Income) originating in PGC 2023	
23	for the 12 month period ended July 2023 (Schedule 11, Sheet 4)	<u>11,004</u>
24	Total Amount to be Refunded	<u><u>4,277,608</u></u>

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2024**

COMMODITY

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	(3 = 1 x 2)	\$	\$	%	(7)	\$
		(2)		(4)	(5 = 3 - 4)	(6)		(8 = 5 x 6 x 7)
August (2023)								
Commodity			1,029,459					
Storage Inventory Recovery			16,169					
Reimbursement of NFGSC Transfer Fee			39					
Market Rate Differential			0					
City Gate Imbalance			0					
Sales Cashout			0					
OFO Penalty			0					
			<u>1,045,666</u>	(1,261,058)	2,306,725	8.50%	18 / 12	294,107
September								
Commodity			965,735					
Storage Inventory Recovery			17,162					
Reimbursement of NFGSC Transfer Fee			35					
Market Rate Differential			0					
City Gate Imbalance			7					
Sales Cashout			105					
OFO Penalty			0					
			<u>983,045</u>	(1,253,936)	2,236,980	8.50%	17 / 12	269,370
October								
Commodity			1,646,045					
Storage Inventory Recovery			25,587					
Reimbursement of NFGSC Transfer Fee			42					
Market Rate Differential			0					
City Gate Imbalance			408					
Sales Cashout			9,558					
OFO Penalty			0					
			<u>1,681,641</u>	442,786	1,238,856	8.50%	16 / 12	140,404
November								
Commodity			3,807,228					
Storage Inventory Recovery			25,415					
Reimbursement of NFGSC Transfer Fee			35					
Market Rate Differential			0					
City Gate Imbalance			10,148					
Sales Cashout			13,653					
OFO Penalty			0					
			<u>3,856,479</u>	5,136,800	(1,280,321)	8.50%	15 / 12	(136,034)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2024

COMMODITY

		<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
		<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
		(1)	(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
December	Commodity	<u>2,799,328</u> 2,799,328	2.7643	<u>7,738,183</u> 7,738,183	9,602,222	(1,864,039)	8.50%	14 / 12	(184,851)
January (2024)	Commodity	<u>3,742,164</u> 3,742,164	2.7643	<u>10,344,464</u> 10,344,464	13,347,395	(3,002,931)	8.50%	13 / 12	(276,520)
February	Commodity	<u>3,909,889</u> 3,909,889	2.7643	<u>10,808,105</u> 10,808,105	11,434,197	(626,092)	8.50%	12 / 12	(53,218)
March	Commodity	<u>3,390,346</u> 3,390,346	2.7643	<u>9,371,934</u> 9,371,934	9,168,244	203,690	8.50%	11 / 12	15,871

PGC Exhibit 21
Schedule 6
Sheet 2
COMMODITY

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2024**

COMMODITY

		<u>Sales</u> Mcf (1)	<u>PGC</u> Rate \$ / Mcf (2)	<u>PGC</u> Revenue \$ (3 = 1 x 2)	<u>Cost of</u> Fuel \$ (4)	<u>Over / (Under)</u> Collections \$ (5 = 3 - 4)	<u>Interest</u> Rate % (6)	<u>Interest</u> Weight (7)	<u>Interest</u> Expense / (Income) \$ (8 = 5 x 6 x 7)
April	Commodity	<u>2,476,675</u> 2,476,675	2.7643	<u>6,846,273</u> 6,846,273	4,809,293	2,036,980	8.50%	10 / 12	144,286
May	Commodity	<u>1,279,705</u> 1,279,705	2.7643	<u>3,537,489</u> 3,537,489	2,824,184	713,305	8.50%	9 / 12	45,473
June	Commodity	<u>647,700</u> 647,700	2.7643	<u>1,790,438</u> 1,790,438	738,087	1,052,351	8.50%	8 / 12	59,633
July	Commodity	<u>403,521</u> 403,521	2.7643	<u>1,115,453</u> 1,115,453	797,919	317,534	8.50%	7 / 12	15,744
	Total	18,649,329		59,119,170	55,786,133	3,333,037			334,266

PGC Exhibit 21
Schedule 6
Sheet 3
COMMODITY

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Reconciliation of Interest on Over / (Under) Collections
Twelve Months Ended July 2023

	<u>Amount</u> \$
Estimated Overcollection of gas cost for the twelve month period August 2022 through July 2023 calculated in PGC 2023 (Schedule 7, Sheets 2 - 4)	28,554,038
Net Interest Expense (Income) to be refunded (Schedule 7, Sheets 2 - 4)	<u>1,337,353</u>
Total Estimate For the Twelve Months Ended July 2023	<u>29,891,391</u>
Actual Overcollection of gas cost for the twelve month period August 2022 through July 2023 (Schedule 7, Sheets 5 - 7)	28,554,038
Net Interest Expense (Income) to be refunded (Schedule 7, Pages 5 - 7)	<u>1,337,353</u>
Total Actual For the Twelve Months Ended July 2023	<u>29,891,391</u>
Amount to be Refunded	<u><u>0</u></u>

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ESTIMATE)**

COMMODITY

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
August (2022)								
Commodity			1,935,676					
Storage Inventory Recovery			21,732					
Reimbursement of NFGSC Transfer Fee			31					
Market Rate Differential			43,497					
City Gate Imbalance			0					
Sales Cashout			57,827					
OFO Penalty			0					
			<u>2,058,763</u>	6,432,635	(4,373,871)	7.00%	18 / 12	(459,256)
September								
Commodity			2,459,303					
Storage Inventory Recovery			17,523					
Reimbursement of NFGSC Transfer Fee			31					
Market Rate Differential			(4,051)					
City Gate Imbalance			18					
Sales Cashout			149,258					
OFO Penalty			0					
			<u>2,622,082</u>	4,733,652	(2,111,570)	7.00%	17 / 12	(209,397)
October								
Commodity			6,110,788					
Storage Inventory Recovery			21,957					
Reimbursement of NFGSC Transfer Fee			23					
Market Rate Differential			0					
City Gate Imbalance			1,289					
Sales Cashout			9,067					
OFO Penalty			0					
			<u>6,143,124</u>	3,850,504	2,292,620	7.00%	16 / 12	213,978
November								
Commodity			9,077,900					
Storage Inventory Recovery			29,541					
Reimbursement of NFGSC Transfer Fee			27					
Market Rate Differential			0					
City Gate Imbalance			75					
Sales Cashout			37,508					
OFO Penalty			0					
			<u>9,145,051</u>	13,411,977	(4,266,926)	7.00%	15 / 12	(373,356)

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ESTIMATE)**

COMMODITY

	<u>Sales</u>	PGC	PGC	Cost of	Over / (Under)	Interest	Interest	Interest
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
December								
Commodity			17,951,330					
Storage Inventory Recovery			20,503					
Reimbursement of NFGSC Transfer Fee			27					
Market Rate Differential			0					
City Gate Imbalance			825					
Sales Cashout			39,134					
OFO Penalty			0					
			<u>18,011,820</u>	22,235,283	(4,223,463)	7.00%	14 / 12	(344,916)
January (2023)								
Commodity			21,453,392					
Storage Inventory Recovery			9,676					
Reimbursement of NFGSC Transfer Fee			31					
Market Rate Differential			0					
City Gate Imbalance			15,317					
Sales Cashout			143,801					
OFO Penalty			189,369					
			<u>21,811,586</u>	13,412,145	8,399,442	7.00%	13 / 12	636,958
February								
Commodity			18,128,152					
Storage Inventory Recovery			3,188					
Reimbursement of NFGSC Transfer Fee			27					
Market Rate Differential			0					
City Gate Imbalance			3,066					
Sales Cashout			2,566					
OFO Penalty			2,823					
			<u>18,139,821</u>	13,030,487	5,109,335	7.00%	12 / 12	357,653
March								
Commodity			14,484,155					
Storage Inventory Recovery			0					
Reimbursement of NFGSC Transfer Fee			0					
Market Rate Differential			0					
City Gate Imbalance			3,835					
Sales Cashout			2,267					
OFO Penalty			0					
			<u>14,490,256</u>	10,817,974	3,672,283	7.00%	11 / 12	235,638

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ESTIMATE)**

COMMODITY

	<u>Sales</u>	PGC	PGC	Cost of	Over / (Under)	Interest	Interest	Interest
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%	(7)	\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)		(8 = 5 x 6 x 7)
April								
Commodity			10,910,726					
Storage Inventory Recovery			0					
Reimbursement of NFGSC Transfer Fee			0					
Market Rate Differential			0					
City Gate Imbalance			40,959					
Sales Cashout			62,630					
OFO Penalty			0					
			<u>11,014,315</u>	(87,508)	11,101,823	7.00%	10 / 12	647,606
May								
Commodity			6,578,205					
Storage Inventory Recovery			4,543					
Reimbursement of NFGSC Transfer Fee			39					
Market Rate Differential			0					
City Gate Imbalance			1,146					
Sales Cashout			23,127					
OFO Penalty			0					
			<u>6,607,059</u>	(571,723)	7,178,782	7.00%	9 / 12	376,886
June								
Commodity			2,332,126					
Storage Inventory Recovery			2,388					
Reimbursement of NFGSC Transfer Fee			27					
Market Rate Differential			0					
City Gate Imbalance			134					
Sales Cashout			76					
OFO Penalty			0					
			<u>2,334,751</u>	(1,046,394)	3,381,144	7.00%	8 / 12	157,787
July								
Commodity			1,157,786					
Storage Inventory Recovery			5,492					
Reimbursement of NFGSC Transfer Fee			23					
Market Rate Differential			0					
City Gate Imbalance			22					
Sales Cashout			0					
OFO Penalty			0					
			<u>1,163,324</u>	(1,231,116)	2,394,440	7.00%	7 / 12	97,773
Total			113,541,953	84,987,915	28,554,038			1,337,353

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ACTUAL)**

COMMODITY

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%	(7)	\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)		(8 = 5 x 6 x 7)
August (2022)								
Commodity			1,935,676					
Storage Inventory Recovery			21,732					
Reimbursement of NFGSC Transfer Fee			31					
Market Rate Differential			43,497					
City Gate Imbalance			0					
Sales Cashout			57,827					
OFO Penalty			0					
			<u>2,058,763</u>	6,432,635	(4,373,871)	7.00%	18 / 12	(459,256)
September								
Commodity			2,459,303					
Storage Inventory Recovery			17,523					
Reimbursement of NFGSC Transfer Fee			31					
Market Rate Differential			(4,051)					
City Gate Imbalance			18					
Sales Cashout			149,258					
OFO Penalty			0					
			<u>2,622,082</u>	4,733,652	(2,111,570)	7.00%	17 / 12	(209,397)
October								
Commodity			6,110,788					
Storage Inventory Recovery			21,957					
Reimbursement of NFGSC Transfer Fee			23					
Market Rate Differential			0					
City Gate Imbalance			1,289					
Sales Cashout			9,067					
OFO Penalty			0					
			<u>6,143,124</u>	3,850,504	2,292,620	7.00%	16 / 12	213,978
November								
Commodity			9,077,900					
Storage Inventory Recovery			29,541					
Reimbursement of NFGSC Transfer Fee			27					
Market Rate Differential			0					
City Gate Imbalance			75					
Sales Cashout			37,508					
OFO Penalty			0					
			<u>9,145,051</u>	13,411,977	(4,266,926)	7.00%	15 / 12	(373,356)

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ACTUAL)**

COMMODITY

	<u>Sales</u>	PGC	PGC	Cost of	Over / (Under)	Interest	Interest	Interest
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%	(7)	\$
	(1)	(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
December								
Commodity			17,951,330					
Storage Inventory Recovery			20,503					
Reimbursement of NFGSC Transfer Fee			27					
Market Rate Differential			0					
City Gate Imbalance			825					
Sales Cashout			39,134					
OFO Penalty			0					
			<u>18,011,820</u>	22,235,283	(4,223,463)	7.00%	14 / 12	(344,916)
January (2023)								
Commodity			21,453,392					
Storage Inventory Recovery			9,676					
Reimbursement of NFGSC Transfer Fee			31					
Market Rate Differential			0					
City Gate Imbalance			15,317					
Sales Cashout			143,801					
OFO Penalty			189,369					
			<u>21,811,586</u>	13,412,144	8,399,442	7.00%	13 / 12	636,958
February								
Commodity			18,128,152					
Storage Inventory Recovery			3,188					
Reimbursement of NFGSC Transfer Fee			27					
Market Rate Differential			0					
City Gate Imbalance			3,066					
Sales Cashout			2,566					
OFO Penalty			2,823					
			<u>18,139,821</u>	13,030,487	5,109,335	7.00%	12 / 12	357,653
March								
Commodity			14,484,155					
Storage Inventory Recovery			0					
Reimbursement of NFGSC Transfer Fee			0					
Market Rate Differential			0					
City Gate Imbalance			3,835					
Sales Cashout			2,267					
OFO Penalty			0					
			<u>14,490,256</u>	10,817,974	3,672,283	7.00%	11 / 12	235,638

PGC Exhibit 2:
Schedule 7
Sheet 6 of 7
COMMODITY

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ACTUAL)**

COMMODITY

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%	(7)	\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)		(8 = 5 x 6 x 7)
April								
Commodity			10,910,726					
Storage Inventory Recovery			0					
Reimbursement of NFGSC Transfer Fee			0					
Market Rate Differential			0					
City Gate Imbalance			40,959					
Sales Cashout			62,630					
OFO Penalty			0					
			<u>11,014,315</u>	(87,508)	11,101,823	7.00%	10 / 12	647,606
May								
Commodity			6,578,205					
Storage Inventory Recovery			4,543					
Reimbursement of NFGSC Transfer Fee			39					
Market Rate Differential			0					
City Gate Imbalance			1,146					
Sales Cashout			23,127					
OFO Penalty			0					
			<u>6,607,059</u>	(571,723)	7,178,782	7.00%	9 / 12	376,886
June								
Commodity			2,332,126					
Storage Inventory Recovery			2,388					
Reimbursement of NFGSC Transfer Fee			27					
Market Rate Differential			0					
City Gate Imbalance			134					
Sales Cashout			76					
OFO Penalty			0					
			<u>2,334,751</u>	(1,046,394)	3,381,144	7.00%	8 / 12	157,787
July								
Commodity			1,157,786					
Storage Inventory Recovery			5,492					
Reimbursement of NFGSC Transfer Fee			23					
Market Rate Differential			0					
City Gate Imbalance			22					
Sales cashout			0					
OFO Penalty			0					
			<u>1,163,324</u>	(1,231,116)	2,394,440	7.00%	7 / 12	97,773
Total			113,541,953	84,987,915	28,554,038			1,337,353

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Reconciliation of Interest on Over / (Under) Collections
Twelve Months Ended July 2023

	<u>Amount</u> \$
Estimated Undercollection of gas cost for the twelve month period August 2022 through July 2023 calculated in PGC-2023 (Schedule 7, Sheets 2 - 4)	(2,010,280)
Net Interest Expense (Income) to be collected (Schedule 7, Sheets 2 - 4)	<u>(201,909)</u>
Total Estimate For the Twelve Months Ended July 2023	<u>(2,212,190)</u>
Actual Undercollection of gas cost for the twelve month period August 2022 through July 2023 (Schedule 7, Sheets 5 - 7)	(2,010,280)
Net Interest Expense (Income) to be collected (Schedule 7, Sheets 5 - 7)	<u>(201,909)</u>
Total Actual For the Twelve Months Ended July 2023	<u>(2,212,190)</u>
Amount to be Refunded	<u><u>0</u></u>

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ESTIMATE)**

DEMAND - NGS

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%		\$
	(1)	(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
August (2022)								
Demand			414,163					
Standby / Priority			20,960					
Standby Overruns			22,209					
NGV - Demand			8,727					
LBS - Demand			1,287					
Overdelivery / Upstream Cap. Surcharge			71,844					
			<u>539,190</u>	217,696	321,495	7.00%	18 / 12	33,757
September								
Demand			456,168					
Standby / Priority			23,647					
Standby Overruns			8,731					
NGV - Demand			8,632					
LBS - Demand			1,273					
Overdelivery / Upstream Cap. Surcharge			62,807					
			<u>561,259</u>	225,640	335,618	7.00%	17 / 12	33,282
October								
Demand			1,162,235					
Standby / Priority			34,061					
Standby Overruns			(14,062)					
NGV - Demand			8,857					
LBS - Demand			1,273					
Overdelivery / Upstream Cap. Surcharge			66,709					
			<u>1,259,074</u>	893,340	365,733	7.00%	16 / 12	34,135
November								
Demand			1,786,883					
Standby / Priority			71,212					
Standby Overruns			(2,320)					
NGV - Demand			8,792					
LBS - Demand			1,273					
Overdelivery / Upstream Cap. Surcharge			77,873					
			<u>1,943,713</u>	4,498,924	(2,555,211)	7.00%	15 / 12	(223,581)

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ESTIMATE)**

DEMAND - NGS

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%	(7)	\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)		(8 = 5 x 6 x 7)
December								
Demand			3,682,694					
Standby / Priority			93,941					
Standby Overruns			6,333					
NGV - Demand			8,920					
LBS - Demand			1,276					
Overdelivery / Upstream Cap. Surcharge			105,795					
			<u>3,898,961</u>	4,282,666	(383,705)	7.00%	14 / 12	(31,336)
January (2023)								
			4,395,497					
Standby/Priority			120,318					
Standby Overruns			21,397					
NGV - Demand			8,984					
LBS - Demand			1,276					
Overdelivery/Upstream Cap. Surcharge			100,892					
			<u>4,648,365</u>	5,238,985	(590,621)	7.00%	13 / 12	(44,789)
February								
Natural Gas Supply Charge			4,164,605					
Standby / Priority			115,662					
Standby Overruns			92					
NGV - Demand			8,631					
LBS - Demand			1,276					
Overdelivery / Upstream Cap. Surcharge			114,083					
			<u>4,404,350</u>	5,516,509	(1,112,159)	7.00%	12 / 12	(77,851)
March								
Natural Gas Supply Charge			3,844,032					
Standby / Priority			104,070					
Standby Overruns			612					
NGV - Demand			7,990					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			95,789					
			<u>4,052,493</u>	5,904,306	(1,851,813)	7.00%	11 / 12	(118,825)

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ESTIMATE)**

DEMAND - NGS

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%		\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
April								
Natural Gas Supply Charge			2,888,480					
Standby / Priority			104,371					
Standby Overruns			487					
NGV - Demand			8,152					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			92,928					
			<u>3,094,418</u>	1,154,713	1,939,706	7.00%	10 / 12	113,149
May								
Natural Gas Supply Charge			1,873,208					
Standby / Priority			68,746					
Standby Overruns			2,217					
NGV - Demand			7,242					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			114,990					
			<u>2,066,401</u>	605,960	1,460,442	7.00%	9 / 12	76,673
June								
Natural Gas Supply Charge			739,659					
Standby / Priority			46,027					
Standby Overruns			73					
NGV - Demand			7,486					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			101,415					
			<u>894,661</u>	720,581	174,079	7.00%	8 / 12	8,124
July								
Natural Gas Supply Charge			354,790					
Standby / Priority			27,438					
Standby Overruns			71					
NGV - Demand			7,202					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			95,992					
			<u>485,493</u>	599,338	(113,845)	7.00%	7 / 12	(4,649)
Total			27,848,378	29,858,658	(2,010,280)			(201,909)

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ACTUAL)**

DEMAND - NGS

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%		\$
	(1)	(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
August (2022)								
Natural Gas Supply Charge			414,163					
Standby / Priority			20,960					
Standby Overruns			22,209					
NGV - Demand			8,727					
LBS - Demand			1,287					
Overdelivery / Upstream Cap. Surcharge			71,844					
			<u>539,190</u>	217,696	321,495	7.00%	18 / 12	33,757
September								
Natural Gas Supply Charge			456,168					
Standby / Priority			23,647					
Standby Overruns			8,731					
NGV - Demand			8,632					
LBS - Demand			1,273					
Overdelivery / Upstream Cap. Surcharge			62,807					
			<u>561,259</u>	225,640	335,618	7.00%	17 / 12	33,282
October								
Natural Gas Supply Charge			1,162,235					
Standby / Priority			34,061					
Standby Overruns			(14,062)					
NGV - Demand			8,857					
LBS - Demand			1,273					
Overdelivery / Upstream Cap. Surcharge			66,709					
			<u>1,259,074</u>	893,340	365,733	7.00%	16 / 12	34,135
November								
Natural Gas Supply Charge			1,786,883					
Standby / Priority			71,212					
Standby Overruns			(2,320)					
NGV - Demand			8,792					
LBS - Demand			1,273					
Overdelivery / Upstream Cap. Surcharge			77,873					
			<u>1,943,713</u>	4,498,924	(2,555,211)	7.00%	15 / 12	(223,581)

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ACTUAL)**

DEMAND - NGS

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%	(7)	\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)		(8 = 5 x 6 x 7)
December								
Natural Gas Supply Charge			3,682,694					
Standby / Priority			93,941					
Standby Overruns			6,333					
NGV - Demand			8,920					
LBS - Demand			1,276					
Overdelivery / Upstream Cap. Surcharge			105,795					
			<u>3,898,961</u>	4,282,666	(383,705)	7.00%	14 / 12	(31,336)
January (2023)								
Natural Gas Supply Charge			4,395,497					
Standby / Priority			120,318					
Standby Overruns			21,397					
NGV - Demand			8,984					
LBS - Demand			1,276					
Overdelivery / Upstream Cap. Surcharge			100,892					
			<u>4,648,365</u>	5,238,986	(590,621)	7.00%	13 / 12	(44,789)
February								
Natural Gas Supply Charge			4,164,605					
Standby / Priority			115,662					
Standby Overruns			92					
NGV - Demand			8,631					
LBS - Demand			1,276					
Overdelivery / Upstream Cap. Surcharge			114,083					
			<u>4,404,350</u>	5,516,508	(1,112,159)	7.00%	12 / 12	(77,851)
March								
Natural Gas Supply Charge			3,844,032					
Standby / Priority			104,070					
Standby Overruns			612					
NGV - Demand			7,990					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			95,789					
			<u>4,052,493</u>	5,904,306	(1,851,813)	7.00%	11 / 12	(118,825)

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ACTUAL)**

DEMAND - NGS

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%	(7)	\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)		(8 = 5 x 6 x 7)
April								
Natural Gas Supply Charge			2,888,480					
Standby / Priority			104,371					
Standby Overruns			487					
NGV - Demand			8,152					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			92,928					
			<u>3,094,418</u>	1,154,712	1,939,706	7.00%	10 / 12	113,150
May								
Natural Gas Supply Charge			1,873,208					
Standby / Priority			68,746					
Standby Overruns			2,217					
NGV - Demand			7,242					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			114,990					
			<u>2,066,401</u>	605,960	1,460,441	7.00%	9 / 12	76,673
June								
Natural Gas Supply Charge			739,659					
Standby / Priority			46,027					
Standby Overruns			73					
NGV - Demand			7,486					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			101,415					
			<u>894,661</u>	720,582	174,079	7.00%	8 / 12	8,124
July								
Natural Gas Supply Charge			354,790					
Standby / Priority			27,438					
Standby Overruns			71					
NGV - Demand			7,202					
LBS - Demand			0					
Overdelivery / Upstream Cap. Surcharge			95,992					
			<u>485,493</u>	599,338	(113,845)	7.00%	7 / 12	(4,649)
Total			27,848,378	29,858,658	(2,010,280)			(201,909)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Reconciliation of Interest on Over / (Under) Collections
Twelve Months Ended July 2023

	<u>Amount</u>
	\$
Estimated Undercollection of gas cost for the twelve month period August 2022 through July 2023 calculated in PGC 2023 (Schedule 7, Sheets 2 - 3)	(572,739)
Net Interest Expense (Income) to be refunded (Schedule 7, Sheets 2 - 3)	<u>(46,610)</u>
Total Estimate For the Twelve Months Ended July 2023	<u>(619,349)</u>
Actual Undercollection of gas cost for the twelve month period August 2022 through July 2023 (Schedule 7, Sheets 4 - 5)	(572,739)
Net Interest Expense (Income) to be refunded (Schedule 7, Sheets 4 - 5)	<u>(46,610)</u>
Total Actual For the Twelve Months Ended July 2023	<u>(619,349)</u>
Amount to be Refunded	<u><u>0</u></u>

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ESTIMATE)**

DEMAND - DC

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%		\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
August (2022)								
Distribution Charge			90,744					
SATC			8,801					
			<u>99,545</u>	540,536	(440,991)	7.00%	18 / 12	(46,304)
September								
Distribution Charge			101,380					
SATC			10,190					
			<u>111,570</u>	540,536	(428,966)	7.00%	17 / 12	(42,539)
October								
Distribution Charge			257,959					
SATC			26,328					
			<u>284,287</u>	540,536	(256,249)	7.00%	16 / 12	(23,917)
November								
Distribution Charge			397,108					
SATC			38,791					
			<u>435,899</u>	541,585	(105,686)	7.00%	15 / 12	(9,248)
December								
Distribution Charge			820,129					
SATC			81,113					
			<u>901,242</u>	582,040	319,202	7.00%	14 / 12	26,068
January (2023)								
Distribution Charge			978,800					
SATC			96,252					
			<u>1,075,051</u>	582,040	493,011	7.00%	13 / 12	37,387

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ESTIMATE)**

DEMAND - DC

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%		\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
February								
	Distribution Charge		915,767					
	SATC		88,934					
			<u>1,004,701</u>	582,040	422,661	7.00%	12 / 12	29,586
March								
	Distribution Charge		835,341					
	SATC		80,865					
			<u>916,206</u>	582,040	334,166	7.00%	11 / 12	21,442
April								
	Distribution Charge		627,940					
	SATC		60,312					
			<u>688,252</u>	582,040	106,212	7.00%	10 / 12	6,196
May								
	Distribution Charge		414,927					
	SATC		40,237					
			<u>455,164</u>	582,040	(126,876)	7.00%	9 / 12	(6,661)
June								
	Distribution Charge		168,805					
	SATC		17,106					
			<u>185,912</u>	582,040	(396,128)	7.00%	8 / 12	(18,486)
July								
	Distribution Charge		80,511					
	SATC		8,434					
			<u>88,945</u>	582,040	(493,095)	7.00%	7 / 12	(20,135)
	Total		6,246,774	6,819,513	(572,739)			(46,610)

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ACTUAL)**

DEMAND - DC

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%		\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
August (2022)								
Distribution Charge			90,744					
SATC			8,801					
			<u>99,545</u>	540,536	(440,991)	7.00%	18 / 12	(46,304)
September								
Distribution Charge			101,380					
SATC			10,190					
			<u>111,570</u>	540,536	(428,966)	7.00%	17 / 12	(42,539)
October								
Distribution Charge			257,959					
SATC			26,328					
			<u>284,287</u>	540,536	(256,249)	7.00%	16 / 12	(23,917)
November								
Distribution Charge			397,108					
SATC			38,791					
			<u>435,899</u>	541,585	(105,686)	7.00%	15 / 12	(9,248)
December								
Distribution Charge			820,129					
SATC			81,113					
			<u>901,242</u>	582,040	319,202	7.00%	14 / 12	26,068
January (2023)								
Distribution Charge			978,800					
SATC			96,252					
			<u>1,075,051</u>	582,040	493,011	7.00%	13 / 12	37,387

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED JULY 2023 (ACTUAL)**

DEMAND - DC

	<u>Sales</u>	<u>PGC</u>	<u>PGC</u>	<u>Cost of</u>	<u>Over / (Under)</u>	<u>Interest</u>	<u>Interest</u>	<u>Interest</u>
	<u>Mcf</u>	<u>Rate</u>	<u>Revenue</u>	<u>Fuel</u>	<u>Collections</u>	<u>Rate</u>	<u>Weight</u>	<u>Expense / (Income)</u>
	(1)	\$ / Mcf	\$	\$	\$	%		\$
		(2)	(3 = 1 x 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)
February								
Distribution Charge			915,767					
SATC			88,934					
			<u>1,004,701</u>	582,040	422,661	7.00%	12 / 12	29,586
March								
Distribution Charge			835,341					
SATC			80,865					
			<u>916,206</u>	582,040	334,166	7.00%	11 / 12	21,442
April								
Distribution Charge			627,940					
SATC			60,312					
			<u>688,252</u>	582,040	106,212	7.00%	10 / 12	6,196
May								
Distribution Charge			414,927					
SATC			40,237					
			<u>455,164</u>	582,040	(126,876)	7.00%	9 / 12	(6,661)
June								
Distribution Charge			168,805					
SATC			17,106					
			<u>185,912</u>	582,040	(396,128)	7.00%	8 / 12	(18,486)
July								
Distribution Charge			80,511					
SATC			8,434					
			<u>88,945</u>	582,040	(493,095)	7.00%	7 / 12	(20,135)
Total			6,246,774	6,819,513	(572,739)			(46,610)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Over / (Under) Collection Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (\$)	<u>Amount</u> (\$)
Reconciliation of over / (under) collection of gas cost for the twelve month period August 2021 through July 2022 originating in PGC 2022		
Estimated amount refunded / (recovered) during the period August 2022 through July 2023		(20,696,467)
Actual amount refunded / (recovered) during the period August 2022 through July 2023		
	<u>Refund / (Surcharge)</u>	
SALES		
August 2022	(145,800)	
September 2022	(354,494)	
October 2022	(860,235)	
November 2022	(1,395,182)	
December 2022	(3,058,624)	
January 2023	(3,663,863)	
February 2023	(3,417,774)	
March 2023	(3,100,828)	
April 2023	(2,333,751)	
May 2023	(1,494,982)	
June 2023	(585,295)	
July 2023	(285,641)	
	<u>(20,696,467)</u>	
(MMNGS & SATC)		
August 2022	0	
September 2022	0	
October 2022	0	
November 2022	0	
December 2022	0	
January 2023	0	
February 2023	0	
March 2023	0	
April 2023	0	
May 2023	0	
June 2023	0	
July 2023	0	
	<u>0</u>	
		<u>(20,696,467)</u>
		<u><u>0</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Over / (Under) Collection Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (\$)	<u>Amount</u> (\$)
Estimated balance of over / (under) collection of gas cost for the twelve month period August 2022 through July 2023 originating in PGC 2023		
Estimated over / (under) collections of gas cost for the twelve month period August 2022 through July 2023		26,585,113
Estimated amount refunded / (recovered) during the period August 2023 through July 2024		
SALES	<u>Rate</u>	<u>Mcf</u>
August 2023		
September 2023		
October 2023		
November 2023		
December 2023	1.2246	2,799,328
January - July 2024	1.2246	15,850,000
		<u>18,649,329</u>
(MMNGS & SATC)		
August 2023		0
September 2023		0
October 2023		0
November 2023		0
December 2023		0
January - July 2024		<u>0</u>
		0
		<u>25,976,493</u>
Amount to be Refunded		608,620

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Over / (Under) Collection Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (\$)	<u>Amount</u> (\$)
Reconciliation of over / (under) collection of gas cost for the twelve month period August 2021 through July 2022 originating in PGC 2022		
Estimated amount refunded / (recovered) during the period August 2022 through July 2023		744,947
Actual amount refunded / (recovered) during the period August 2022 through July 2023		
	<u>Refund / (Surcharge)</u>	
SALES		
August 2022	(10,570)	
September 2022	16,646	
October 2022	37,884	
November 2022	55,987	
December 2022	109,550	
January 2023	131,661	
February 2023	122,795	
March 2023	110,925	
April 2023	83,493	
May 2023	54,027	
June 2023	20,963	
July 2023	9,943	
	<u>743,302</u>	
LBS & NGV		
August 2022	(680)	
September 2022	225	
October 2022	231	
November 2022	229	
December 2022	219	
January 2023	220	
February 2023	212	
March 2023	191	
April 2023	195	
May 2023	173	
June 2023	172	
July 2023	165	
	<u>1,552</u>	
(MMNGS & SATC)		
August 2022	(100)	
September 2022	33	
October 2022	33	
November 2022	33	
December 2022	31	
January 2023	31	
February 2023	31	
March 2023	0	
April 2023	0	
May 2023	0	
June 2023	0	
July 2023	0	
	<u>93</u>	<u>744,947</u>
		<u><u>0</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Over / (Under) Collection Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (\$)	<u>Amount</u> (\$)
Estimated balance of over / (under) collection of gas cost for the twelve month period August 2022 through July 2023 originating in PGC 2023		
Estimated over / (under) collection of gas cost for the twelve month period August 2022 through July 2023		(2,090,857)
Estimated amount refunded / (recovered) during the period August 2023 through July 2024		
	<u>Rate</u>	<u>Mcf</u>
SALES		<u>Refund / (Surcharge)</u>
August 2023		(7,032)
September 2023		(24,907)
October 2023		(39,043)
November 2023		(110,637)
December 2023	(0.0963)	(269,575)
January - July 2024	(0.0963)	(1,526,355)
		<u>18,649,329</u>
		(1,977,550)
LBS & NGV		
August 2023		163
September 2023		(293)
October 2023		(493)
November 2023		(47)
December 2023		0
January - July 2024		0
		<u>0</u>
		(671)
(MMNGS & SATC)		
August 2023		0
September 2023		0
October 2023		0
November 2023		0
December 2023		0
January - July 2024		0
		<u>0</u>
		0
		(1,978,220)
Amount to be Recovered		<u><u>(112,637)</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Over / (Under) Collection Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (\$)	<u>Amount</u> (\$)
Reconciliation of over / (under) collection of gas cost for the twelve month period August 2021 through July 2022 originating in PGC 2022		
Estimated amount refunded / (recovered) during the period August 2022 through July 2023		(482,931)
Actual amount refunded / (recovered) during the period August 2022 through July 2023		
SALES	<u>Refund / (Surcharge)</u>	
August 2022	(4,517)	
September 2022	(7,893)	
October 2022	(20,360)	
November 2022	(30,135)	
December 2022	(65,347)	
January 2023	(77,903)	
February 2023	(70,357)	
March 2023	(66,124)	
April 2023	(49,733)	
May 2023	(30,056)	
June 2023	(11,892)	
July 2023	(5,534)	
	<u>(439,852)</u>	
LBS & NGV		
August 2022	0	
September 2022	0	
October 2022	0	
November 2022	0	
December 2022	0	
January 2023	0	
February 2023	0	
March 2023	0	
April 2023	0	
May 2023	0	
June 2023	0	
July 2023	0	
	<u>0</u>	
SATC		
August 2022	(449)	
September 2022	(791)	
October 2022	(2,073)	
November 2022	(2,940)	
December 2022	(6,462)	
January 2023	(7,654)	
February 2023	(6,831)	
March 2023	(6,401)	
April 2023	(4,774)	
May 2023	(2,916)	
June 2023	(1,205)	
July 2023	(584)	
	<u>(43,079)</u>	
		<u>(482,931)</u>
		<u><u>0</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Over / (Under) Collection Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (\$)	<u>Amount</u> (\$)
Estimated balance of over / (under) collection of gas cost for the twelve month period August 2022 through July 2023 originating in PGC 2023		
Estimated over / (under) collections of gas cost for the twelve month period August 2022 through July 2023		(685,621)
Estimated amount refunded / (recovered) during the period August 2023 through July 2024		
SALES	<u>Rate</u>	<u>Mcf</u>
August 2023		<u>Refund / (Surcharge)</u>
September 2023		(6,715)
October 2023		(9,166)
November 2023		(15,531)
December 2023		(38,146)
January - July 2024	(0.0290)	(81,181)
	(0.0290)	(459,650)
		<u>18,649,329</u>
		(610,389)
LBS & NGV		
August 2023		0
September 2023		0
October 2023		0
November 2023		0
December 2023		0
January - July 2024		0
		<u>0</u>
		0
SATC	<u>SATC Mcf</u>	
August 2023		(674)
September 2023		(904)
October 2023		(1,547)
November 2023		(3,651)
December 2023	(0.0290)	(7,862)
January - July 2024	(0.0290)	(45,540)
		<u>1,841,448</u>
		(60,178)
		<u>(670,567)</u>
Amount to be Recovered		<u>(15,054)</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Refund / (Surcharge) Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (\$)	<u>Amount</u> (\$)
Reconciliation of refund / (surcharge) established in PGC 2022		
Estimated amount refunded / (recovered) during the period August 2022 through July 2023		0
Actual amount refunded / (recovered) during the period August 2022 through July 2023		
	<u>Refund / (Surcharge)</u>	
SALES		
August 2022	0	
September 2022	0	
October 2022	0	
November 2022	0	
December 2022	0	
January 2023	0	
February 2023	0	
March 2023	0	
April 2023	0	
May 2023	0	
June 2023	0	
July 2023	0	
	0	
SATC		
August 2022	0	
September 2022	0	
October 2022	0	
November 2022	0	
December 2022	0	
January 2023	0	
February 2023	0	
March 2023	0	
April 2023	0	
May 2023	0	
June 2023	0	
July 2023	0	
	0	
		0
		0

Pennsylvania Division

Calculation of Refund / (Surcharge) Balances Included in PGC 2024

Description			<u>Amount</u> (\$)	<u>Amount</u> (\$)
Reconciliation of refund / (surcharge) established in PGC 2023				
Estimated amount refunded / (recovered) during the period August 2023 through July 2024				0
Estimated amount refunded / (recovered) during the period August 2023 through July 2024				
	<u>Rate</u>	<u>Mcf</u>	<u>Refund / (Surcharge)</u>	
SALES				
August 2023			0	
September 2023			0	
October 2023			0	
November 2023			0	
December 2023	0.0000	2,799,328	0	
January - July 2024	0.0000	15,850,000	0	
		18,649,329	0	
(MMNGS & SATC)				
August 2023			0	
September 2023			0	
October 2023			0	
November 2023			0	
December 2023			0	
January - July 2024			0	
			0	0
				0
				0
				0
*Due to small amount, amount rolled into Sheet 8 Comm efactor				0
in efactor				0
				0

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Refund / (Surcharge) Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (<u>\$</u>)	<u>Amount</u> (<u>\$</u>)
Reconciliation of refund / (surcharge) established in PGC 2022		
Estimated amount refunded / (recovered) during the period August 2022 through July 2023		785,900
Actual amount refunded / (recovered) during the period August 2022 through July 2023		
	<u>Refund / (Surcharge)</u>	
SALES		
August 2022	6,832	
September 2022	14,493	
October 2022	36,656	
November 2022	55,843	
December 2022	114,853	
January 2023	137,583	
February 2023	128,288	
March 2023	116,451	
April 2023	87,524	
May 2023	55,786	
June 2023	21,526	
July 2023	10,065	
	<u>785,900</u>	
LBS & NGV		
August 2022	0	
September 2022	0	
October 2022	0	
November 2022	0	
December 2022	0	
January 2023	0	
February 2023	0	
March 2023	0	
April 2023	0	
May 2023	0	
June 2023	0	
July 2023	0	
	<u>0</u>	
SATC		
August 2022	0	
September 2022	0	
October 2022	0	
November 2022	0	
December 2022	0	
January 2023	0	
February 2023	0	
March 2023	0	
April 2023	0	
May 2023	0	
June 2023	0	
July 2023	0	
	<u>0</u>	
		<u>785,900</u>
		<u><u>0</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Refund / (Surcharge) Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (<u>\$</u>)	<u>Amount</u> (<u>\$</u>)
Reconciliation of refund / (surcharge) established in PGC 2023		
Estimated amount refunded / (recovered) during the period August 2023 through July 2024		118,690
Actual amount refunded / (recovered) during the period August 2023 through July 2024		
	<u>Rate</u>	<u>Mcf</u>
SALES		<u>Refund / (Surcharge)</u>
August 2023		5,256
September 2023		1,224
October 2023		2,781
November 2023		7,222
December 2023	0.0055	2,799,328
January - July 2024	0.0055	15,850,000
		<u>18,649,329</u>
		119,053
LBS & NGV		
August 2023		0
September 2023		0
October 2023		0
November 2023		0
December 2023		0
January - July 2024		0
		<u>0</u>
		0
SATC	<u>MMNGS Mcf</u>	<u>SATC Mcf</u>
August 2023		0
September 2023		0
October 2023		0
November 2023		0
December 2023		0
January - July 2024		0
		<u>0</u>
		0
		119,053
Amount to be Recovered		<u><u>(363)</u></u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Refund / (Surcharge) Balances Included in the PGC 2024

<u>Description</u>	<u>Amount</u> (\$)	<u>Amount</u> (\$)
Reconciliation of refund / (surcharge) established in PGC 2022		
Estimated amount refunded / (recovered) during the period August 2022 through July 2023		923
Actual amount refunded / (recovered) during the period August 2022 through July 2023		
	<u>Refund / (Surcharge)</u>	
SALES		
August 2022	41	
September 2022	14	
October 2022	7	
November 2022	31	
December 2022	215	
January 2023	224	
February 2023	134	
March 2023	142	
April 2023	76	
May 2023	26	
June 2023	5	
July 2023	8	
	<u>923</u>	
LBS & NGV¹		
August 2022	0	
September 2022	0	
October 2022	0	
November 2022	0	
December 2022	0	
January 2023	0	
February 2023	0	
March 2023	0	
April 2023	0	
May 2023	0	
June 2023	0	
July 2023	0	
	<u>0</u>	
		<u>923</u>
		<u><u>0</u></u>

1 LBS & NGV Supplier refund (if any) included in Sales amount as they share the same line item type within SAP reporting

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Refund or Surcharge Balances Included in the PGC 2024

<u>Description</u>		<u>Amount</u> (\$)	<u>Amount</u> (\$)
Reconciliation of refund / (surcharge) established in PGC 2023			
Estimated amount refunded / (recovered) during the period August 2023 through July 2024			247,991
Actual amount refunded / (recovered) during the period August 2023 through July 2024			
SALES	<u>Rate</u>	<u>Mcf</u>	<u>Refund / (Surcharge)</u>
August 2023			1,982
September 2023			4,287
October 2023			6,812
November 2023			15,709
December 2023	0.0105	2,799,328	29,393
January - July 2024	0.0105	15,850,000	166,425
		<u>18,649,329</u>	<u>224,608</u>
LBS & NGV			
August 2023			0
September 2023			0
October 2023			0
November 2023			0
December 2023			0
January - July 2024			<u>0</u>
			0
			<u>224,608</u>
Amount to be Refunded			<u>23,382</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Refunds From and Payments to Gas Suppliers

<u>Refund From</u>	<u>Date Received</u>	<u>Refund Amount</u> \$	<u>INTEREST</u>			<u>Amount</u> \$	<u>Total Refund Plus Interest</u> \$
			<u>Rate</u>	<u>Weight</u>			
A.		0	0.00%	0	/ 12	0	0
B.		0	0.00%	0	/ 12	0	0
TOTAL							

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Reconciliation of Interest on Storage Injections / Withdrawals

<u>Description</u>	<u>Amount</u> <u>(\$)</u>
Reconciliation of interest expense / (income) due to / (from) customers for the twelve month period August 2021 through July 2022 originating in PGC 2022 (PGC 2023 - Rec. E-factor)	
Estimated amount passed back / (recovered) during the period August 2022 through July 2023 in E Factor	166,074
Actual amount passed back / (recovered) during the period August 2022 through July 2023 in E-Factor	

	<u>Refund / (Surcharge)</u>	
SALES		
August 2022	1,216	
September 2022	3,286	
October 2022	7,894	
November 2022	11,938	
December 2022	24,153	
January 2023	28,927	
February 2023	26,997	
March 2023	24,475	
April 2023	18,411	
May 2023	11,845	
June 2023	4,652	
July 2023	2,281	
	166,074	
SATC		
August 2022	0	
September 2022	0	
October 2022	0	
November 2022	0	
December 2022	0	
January 2023	0	
February 2023	0	
March 2023	0	
April 2023	0	
May 2023	0	
June 2023	0	
July 2023	0	
	0	
		166,074
		0

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Reconciliation of Interest on Storage Injections / Withdrawals

<u>Description</u>	<u>Amount</u> (\$)
Estimated interest expense / (income) due to / (from) customers for the twelve month period August 2022 through July 2023 in C-Factor (PGC 2023 - C Factor)	16,142

Actual amount passed back / (recovered) during the period August 2022 through July 2023 in C Factor

	<u>Refund / (Surcharge)</u>	
SALES		
August 2022	2,088	
September 2022	(140)	
October 2022	(17)	
November 2022	4,400	
December 2022	20,256	
January 2023	24,117	
February 2023	4,466	
March 2023	(13,957)	
April 2023	(10,359)	
May 2023	(8,371)	
June 2023	(4,318)	
July 2023	(2,023)	
	16,142	
		16,142
		0

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Reconciliation of Interest on Storage Injections / Withdrawals

<u>Description</u>	<u>Amount</u> (\$)

Estimated balance of interest expense / (income) due to / (from) customer for the twelve month period August 2022 through July 2023 originating in PGC 2023 (PGC 2024 - Rec. E-factor)

Estimated interest expense / (income) due to / (from) customers for the twelve month period August 2022 through July 2023 in C/E Factor	(487,365)

Estimated amount passed back / (recovered) during the period August 2023 through July 2024 in E Factor

	<u>Rate</u>	<u>Mcf</u>	<u>Refund / (Surcharge)</u>	
SALES				
August 2023			(3,051)	
September 2023			(9,169)	
October 2023			(14,396)	
November 2023			(31,819)	
December 2023	(0.0225)	2,799,328	(62,985)	
January - July 2024	(0.0225)	15,850,000	(356,625)	
		<u>18,649,329</u>	<u>(478,045)</u>	
SATC				
		<u>MMNGS Mcf</u>	<u>SATC Mcf</u>	
August 2023				
September 2023				
October 2023				
November 2023				
December 2023	(0.0225)	0	0	0
January - July 2024	(0.0225)	0	0	0
		<u>0</u>	<u>0</u>	<u>0</u>
				<u>(478,045)</u>
Amount to be Recovered		in PGC 2024		<u>(9,320)</u>

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division

Calculation of Reconciliation of Interest on Storage Injections / Withdrawals

<u>Description</u>	<u>Amount</u> (\$)
Estimated interest expense / (income) due to / (from) customers for the twelve month period August 2023 through July 2024 in C-Factor (PGC 2024 - C factor)	(12,081)

Estimated amount passed back / (recovered) during the period August 2023 through July 2024 in C Factor

	<u>Rate</u>	<u>Mcf</u>	<u>Refund / (Surcharge)</u>	
SALES				
August 2023			(1,628)	
September 2023			(1,892)	
October 2023			(3,116)	
November 2023			(3,395)	
December 2023	(0.0007)	2,799,328	(1,960)	
January - July 2024	(0.0007)	15,850,000	(11,095)	
		<u>18,649,329</u>	<u>(23,085)</u>	
				<u>(23,085)</u>
Amount to be Refunded		in PGC 2024		<u><u>11,004</u></u>

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED NOVEMBER 2023**

DEMAND - NGS

	<u>PGC Revenue</u> \$ (1)	<u>Cost of Fuel</u> \$ (2)	<u>Over / (Under) Collections</u> \$ (3 = 1 - 2)
December (2022)			
Demand	3,682,694		
Standby / Priority	93,941		
Standby Overruns	6,333		
NGV - Demand	8,920		
LBS - Demand	1,276		
Overdelivery / Upstream Cap. Surcharge	105,795		
	3,898,961	4,282,666	(383,705)
January (2023)			
Demand	4,395,497		
Standby / Priority	120,318		
Standby Overruns	21,397		
NGV - Demand	8,984		
LBS - Demand	1,276		
Overdelivery / Upstream Cap. Surcharge	100,892		
	4,648,365	5,238,985	(590,621)
February			
Demand	4,164,605		
Standby / Priority	115,662		
Standby Overruns	92		
NGV - Demand	8,631		
LBS - Demand	1,276		
Overdelivery / Upstream Cap. Surcharge	114,083		
	4,404,350	5,516,509	(1,112,159)
March			
Demand	3,844,032		
Standby / Priority	104,070		
Standby Overruns	612		
NGV - Demand	7,990		
LBS - Demand	0		
Overdelivery / Upstream Cap. Surcharge	95,789		
	4,052,493	5,904,306	(1,851,813)

PGC Exhibit 21A
Schedule 1
Sheet 1
DEMAND - NGS

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED NOVEMBER 2023**

DEMAND - NGS

	<u>PGC Revenue</u> \$ (1)	<u>Cost of Fuel</u> \$ (2)	<u>Over / (Under) Collections</u> \$ (3 = 1 - 2)
April			
Demand	2,888,480		
Standby / Priority	104,371		
Standby Overruns	487		
NGV - Demand	8,152		
LBS - Demand	0		
Overdelivery / Upstream Cap. Surcharge	92,928		
	3,094,418	1,154,713	1,939,706
May			
Demand	1,873,208		
Standby / Priority	68,746		
Standby Overruns	2,217		
NGV - Demand	7,242		
LBS - Demand	0		
Overdelivery / Upstream Cap. Surcharge	114,990		
	2,066,401	605,960	1,460,442
June			
Demand	739,659		
Standby / Priority	46,027		
Standby Overruns	73		
NGV - Demand	7,486		
LBS - Demand	0		
Overdelivery / Upstream Cap. Surcharge	101,415		
	894,661	720,581	174,079
July			
Demand	354,790		
Standby / Priority	27,438		
Standby Overruns	71		
NGV - Demand	7,202		
LBS - Demand	0		
Overdelivery / Upstream Cap. Surcharge	95,992		
	485,493	599,338	(113,845)

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED NOVEMBER 2023**

DEMAND - NGS

	<u>PGC</u> <u>Revenue</u> \$ (1)	<u>Cost of</u> <u>Fuel</u> \$ (2)	<u>Over / (Under)</u> <u>Collections</u> \$ (3 = 1 - 2)
August			
Demand	404,702		
Standby / Priority	24,216		
Standby Overruns	391		
NGV - Demand	7,121		
LBS - Demand	0		
Overdelivery / Upstream Cap. Surcharge	88,622		
	<u>525,052</u>	713,742	(188,691)
September			
Demand	488,557		
Standby / Priority	27,647		
Standby Overruns	684		
NGV - Demand	7,587		
LBS - Demand	0		
Overdelivery / Upstream Cap. Surcharge	82,896		
	<u>607,370</u>	303,844	303,526
October			
Demand	810,447		
Standby / Priority	33,313		
Standby Overruns	2		
NGV - Demand	12,759		
LBS - Demand	0		
Overdelivery / Upstream Cap. Surcharge	83,388		
	<u>939,909</u>	16,878	923,031
November			
Demand	2,215,172		
Standby / Priority	63,466		
Standby Overruns	8,269		
NGV - Demand	1,214		
LBS - Demand	0		
Overdelivery / Upstream Cap. Surcharge	93,690		
	<u>2,381,811</u>	4,839,367	(2,457,556)
Total	27,999,284	29,896,889	(1,897,605)

PGC Exhibit 21A
Schedule 1
Sheet 3
DEMAND - NGS

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED NOVEMBER 2023**

DEMAND - DC

	<u>PGC Revenue</u> \$ (1)	<u>Cost of Fuel</u> \$ (2)	<u>Over / (Under) Collections</u> \$ (3 = 1 - 2)
December (2022)			
Distribution Charge	820,129		
SATC	81,113		
	901,242	582,040	319,202
January (2023)			
Distribution Charge	978,800		
SATC	96,252		
	1,075,051	582,040	493,011
February			
Distribution Charge	915,767		
SATC	88,934		
	1,004,701	582,040	422,661
March			
Distribution Charge	835,341		
SATC	80,865		
	916,206	582,040	334,166
April			
Distribution Charge	627,940		
SATC	60,312		
	688,252	582,040	106,212
May			
Distribution Charge	414,927		
SATC	40,237		
	455,164	582,040	(126,876)

PGC Exhibit 21A
Schedule 2
Sheet 1
DEMAND - DC

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED NOVEMBER 2023**

DEMAND - DC

		<u>PGC Revenue</u> \$ (1)	<u>Cost of Fuel</u> \$ (2)	<u>Over / (Under) Collections</u> \$ (3 = 1 - 2)
June	Distribution Charge	168,805		
	SATC	17,106		
		<u>185,912</u>	582,040	(396,128)
July	Distribution Charge	80,511		
	SATC	8,434		
		<u>88,945</u>	582,040	(493,095)
August	Distribution Charge	85,212		
	SATC	8,576		
		<u>93,788</u>	582,040	(488,252)
September	Distribution Charge	97,326		
	SATC	9,691		
		<u>107,017</u>	582,040	(475,023)
October	Distribution Charge	162,160		
	SATC	16,169		
		<u>178,329</u>	582,040	(403,711)
November	Distribution Charge	438,048		
	SATC	42,065		
		<u>480,113</u>	582,096	(101,983)
Total		6,174,719	6,984,536	(809,817)

PGC Exhibit 21A
Schedule 2
Sheet 2
DEMAND - DC

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED NOVEMBER 2023**

COMMODITY

	<u>PGC Revenue</u>	<u>Cost of Fuel</u>	<u>Over / (Under) Collections</u>
	\$	\$	\$
	(3 = 1 x 2)	(4)	(5 = 3 - 4)
December (2022)			
Commodity	17,951,330		
Storage Inventory Recovery	20,503		
Reimbursement of NFGSC Transfer Fee	27		
Market Rate Differential	0		
City Gate Imbalance	825		
Sales Cashout	39,134		
OFO Penalty	0		
	18,011,820	22,235,283	(4,223,463)
January (2023)			
Commodity	21,453,392		
Storage Inventory Recovery	9,676		
Reimbursement of NFGSC Transfer Fee	31		
Market Rate Differential	0		
City Gate Imbalance	15,317		
Sales Cashout	143,801		
OFO Penalty	189,369		
	21,811,586	13,412,145	8,399,442
February			
Commodity	18,128,152		
Storage Inventory Recovery	3,188		
Reimbursement of NFGSC Transfer Fee	27		
Market Rate Differential	0		
City Gate Imbalance	3,066		
Sales Cashout	2,566		
OFO Penalty	2,823		
	18,139,821	13,030,487	5,109,335
March			
Commodity	14,484,155		
Storage Inventory Recovery	0		
Reimbursement of NFGSC Transfer Fee	0		
Market Rate Differential	0		
City Gate Imbalance	3,835		
Sales Cashout	2,267		
OFO Penalty	0		
	14,490,256	10,817,974	3,672,283

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED NOVEMBER 2023**

COMMODITY

	<u>PGC Revenue</u>	<u>Cost of Fuel</u>	<u>Over / (Under) Collections</u>
	\$	\$	\$
	(3 = 1 x 2)	(4)	(5 = 3 - 4)
April			
Commodity	10,910,726		
Storage Inventory Recovery	0		
Reimbursement of NFGSC Transfer Fee	0		
Market Rate Differential	0		
City Gate Imbalance	40,959		
Sales Cashout	62,630		
OFO Penalty	0		
	<u>11,014,315</u>	(87,508)	11,101,823
May			
Commodity	6,578,205		
Storage Inventory Recovery	4,543		
Reimbursement of NFGSC Transfer Fee	39		
Market Rate Differential	0		
City Gate Imbalance	1,146		
Sales Cashout	23,127		
OFO Penalty	0		
	<u>6,607,059</u>	(571,723)	7,178,782
June			
Commodity	2,332,126		
Storage Inventory Recovery	2,388		
Reimbursement of NFGSC Transfer Fee	27		
Market Rate Differential	0		
City Gate Imbalance	134		
Sales Cashout	76		
OFO Penalty	0		
	<u>2,334,751</u>	(1,046,394)	3,381,144
July			
Commodity	1,157,786		
Storage Inventory Recovery	5,492		
Reimbursement of NFGSC Transfer Fee	23		
Market Rate Differential	0		
City Gate Imbalance	22		
Sales Cashout	0		
OFO Penalty	0		
	<u>1,163,324</u>	(1,231,116)	2,394,440

PGC Exhibit 21A
Schedule 3
Sheet 2
COMMODITY

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
PENNSYLVANIA DIVISION
STATEMENT OF TOTAL OVER / (UNDER) COLLECTIONS
TWELVE MONTHS ENDED NOVEMBER 2023**

COMMODITY

	<u>PGC Revenue</u>	<u>Cost of Fuel</u>	<u>Over / (Under) Collections</u>
	\$	\$	\$
	(3 = 1 x 2)	(4)	(5 = 3 - 4)
August			
Commodity	1,029,459		
Storage Inventory Recovery	16,169		
Reimbursement of NFGSC Transfer Fee	39		
Market Rate Differential	0		
City Gate Imbalance	0		
Sales Cashout	0		
OFO Penalty	0		
	<u>1,045,666</u>	(1,261,058)	2,306,725
September			
Commodity	965,735		
Storage Inventory Recovery	17,162		
Reimbursement of NFGSC Transfer Fee	35		
Market Rate Differential	0		
City Gate Imbalance	7		
Sales Cashout	105		
OFO Penalty	0		
	<u>983,045</u>	(1,253,936)	2,236,980
October			
Commodity	1,646,045		
Reimbursement of NFGSC Transfer Fee	42		
Market Rate Differential	0		
City Gate Imbalance	408		
Sales Cashout	9,558		
OFO Penalty	0		
	<u>1,681,641</u>	442,786	1,238,856
November			
Commodity	3,807,228		
Storage Inventory Recovery	25,415		
Reimbursement of NFGSC Transfer Fee	35		
Market Rate Differential	0		
City Gate Imbalance	10,148		
Sales Cashout	13,653		
OFO Penalty	0		
	<u>3,856,479</u>	5,136,800	(1,280,321)
Total	101,139,764	59,623,739	41,516,025

LINK YEAR - CALCULATION FLOWS TO SCHEDULE 5 - COMMODITY

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Calculation of Interest on Storage Injections / Withdrawals (C Factor Recovery / (Passback))
Twelve Months Ended July 2024

Month	Open / Closed Period	Injections Mcf (1)	Withdrawals Mcf (2)	Rate Differential \$/ Mcf (3)	Cost Charged Through PGC But Not Paid By Distribution \$ (4 = 2 x 3)	Cost Paid By Distribution But Not Charged Through PGC \$ (5 = 1 x 3)	Storage (Net Paid) / Net Charged \$ (6 = 4 + 5)	Interest Weight (7)	Interest Rate ¹ % (8)	Gross Storage Interest Expense / (Revenue) \$ (9 = [6 x (7 x 8)])
August 2023	Closed	975,930	14,830	4.5022	66,768	(4,393,832)	(4,327,064)	12 / 12	8.50%	(367,800)
September	Closed	1,169,912	14,590	4.5022	65,687	(5,267,178)	(5,201,491)	11 / 12	8.50%	(405,283)
October	Closed	1,052,094	7,198	4.1764	30,062	(4,393,959)	(4,363,897)	10 / 12	8.50%	(309,109)
November	Closed	66,929	728,785	4.1764	3,043,693	(279,522)	2,764,171	9 / 12	8.50%	176,216
December	Open	0	899,868	4.1764	3,758,202	0	3,758,202	8 / 12	8.50%	212,965
January 2024	Open	0	1,885,072	4.1764	7,872,805	0	7,872,805	7 / 12	8.50%	390,360
February	Open	0	1,471,206	4.1764	6,144,334	0	6,144,334	6 / 12	8.50%	261,134
March	Open	0	1,683,651	4.1764	7,031,589	0	7,031,589	5 / 12	8.50%	249,035
April	Open	83,636	0	4.1764	0	(349,295)	(349,295)	4 / 12	8.50%	(9,897)
May	Open	1,201,098	0	4.1764	0	(5,016,258)	(5,016,258)	3 / 12	8.50%	(106,595)
June	Open	1,158,886	0	4.1764	0	(4,839,964)	(4,839,964)	2 / 12	8.50%	(68,566)
July	Open	1,167,566	0	4.1764	0	(4,876,216)	(4,876,216)	1 / 12	8.50%	(34,540)
TOTAL		6,876,051	6,705,199		28,013,140	(29,416,224)	(1,403,084)			(12,081)
Estimated Storage Interest Income Due From PGC Customers										<u>(\$12,081)</u>

¹ The storage over / (under) interest rate is based upon the prime interest rate in effect within 60 days of this filing.

RATE YEAR - CALCULATION FLOWS TO SCHEDULE 5 - COMMODITY

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Calculation of Interest on Storage Injections / Withdrawals (C Factor Recovery / (Passback))
Twelve Months Ended July 2025

<u>Month</u>	<u>Open / Closed Period</u>	<u>Injections</u>	<u>Withdrawals</u>	<u>Rate</u>	<u>Cost Charged Through PGC But Not Paid By Distribution</u>	<u>Cost Paid By Distribution But Not Charged Through PGC</u>	<u>Storage (Net Paid) / Net Charged</u>	<u>Interest Weight</u>	<u>Interest Rate ¹</u>	<u>Gross Storage Interest Expense / (Revenue)</u>
		<u>Mcf</u>	<u>Mcf</u>	<u>\$ / Mcf</u>	<u>\$</u>	<u>\$</u>	<u>\$</u>		<u>%</u>	<u>\$</u>
		<u>(1)</u>	<u>(2)</u>	<u>(3)</u>	<u>(4 = 2 x 3)</u>	<u>(5 = 1 x 3)</u>	<u>(6 = 4 + 5)</u>	<u>(7)</u>	<u>(8)</u>	<u>(9 = [6 x (7 x 8)])</u>
August 2024	Open	1,051,167	0	4.1764	0	(4,390,085)	(4,390,085)	12 / 12	8.50%	(373,157)
September	Open	1,129,405	0	4.1764	0	(4,716,842)	(4,716,842)	11 / 12	8.50%	(367,521)
October	Open	1,021,324	0	5.3391	0	(5,452,991)	(5,452,991)	10 / 12	8.50%	(386,254)
November	Open	0	778,698	5.3391	4,157,577	0	4,157,577	9 / 12	8.50%	265,046
December	Open	0	899,868	5.3391	4,804,517	0	4,804,517	8 / 12	8.50%	272,256
January 2025	Open	0	1,885,072	5.3391	10,064,659	0	10,064,659	7 / 12	8.50%	499,039
February	Open	0	1,471,206	5.3391	7,854,967	0	7,854,967	6 / 12	8.50%	333,836
March	Open	0	1,683,651	5.3391	8,989,242	0	8,989,242	5 / 12	8.50%	318,369
April	Open	83,636	0	5.3391	0	(446,542)	(446,542)	4 / 12	8.50%	(12,652)
May	Open	1,201,098	0	5.3391	0	(6,412,826)	(6,412,826)	3 / 12	8.50%	(136,273)
June	Open	1,158,886	0	5.3391	0	(6,187,450)	(6,187,450)	2 / 12	8.50%	(87,656)
July	Open	1,167,566	0	5.3391	0	(6,233,795)	(6,233,795)	1 / 12	8.50%	(44,156)
TOTAL		6,813,082	6,718,495		35,870,962	(33,840,531)	2,030,431			280,878
Estimated Storage Interest Expense Due to PGC Customers										\$280,878
PGC Volumes (Exhibit 22)										<u>21,817,752</u>
PGC (Passback) / Recovery Rate \$/Mcf										<u>(\$0.0129)</u>

1 The storage over / (under) interest rate is based upon the prime interest rate in effect within 60 days of this filing.

Section 53.64 (i) (1) (v)

"

(i) Utilities shall comply with the following:

(1) Concurrent with the filing of a tariff reflecting increases or decreases in purchased gas expenses, gas utilities under 66 Pa. C.S. Section 1307(f) recovering expenses under that section must file a statement for the 12-month period ending 2 months prior to the filing date under 66 Pa. C.S. Section 1307(f) as published in accordance with subsection (b) which shall specify:

. . . "

(v) How these costs are consistent with a least cost procurement policy, as required by 66 Pa. C.S. Section 1318 (relating to determination of just and reasonable natural gas rates).

. . . "

Explanation that Over/Under Collections
for the Twelve Months Ended November 30, 2023
Resulted from a Least-Cost Procurement Policy

As shown on Exhibit No. 21-A Demand - NGS, sheets 1 through 3 and Exhibit No. 21-A Demand – DC sheets 1 and 2, National Fuel Gas Distribution Corporation ("Distribution") under-collected demand gas costs by a net amount of \$2,707,422 during the twelve months ended November 30, 2023. In Exhibit 21-A Commodity sheets 1 through 3, Distribution over-collected commodity gas costs by \$41,516,025 for the twelve months ended November 30, 2023. The total gas cost over-recovery for the period is \$38,808,603.

Distribution under-collected its projected demand gas costs primarily because actual demand costs were higher than projected demand costs. Demand costs were projected for the twelve months ended November 2023 at \$1.7580/Mcf. Actual

1 demand costs for the period were \$1.8972/Mcf. This resulted in an under-recovery of
2 \$0.1392/Mcf or \$2.7 million [$\$0.1392 \times 19,439,464$ Mcf] for the period.

3 Distribution over-collected its commodity costs primarily because actual
4 commodity costs were lower than projected. Projected commodity costs were
5 \$5.2028/Mcf for the period. Actual commodity costs were \$3.0671/Mcf for the period.
6 This resulted in an over-recovery of commodity costs of \$2.1357/Mcf or \$41.5 million
7 [$\$2.1357 \times 19,439,464$ Mcf] for the period.

8 Despite the over-recovery of total gas costs, gas costs would have been
9 higher if not for Distribution's "least cost" fuel procurement practices.

10 Distribution's Pennsylvania Division contracts for pipeline capacity on
11 Tennessee Gas Pipeline Company, LLC ("Tennessee" or "TGP"), Texas Eastern
12 Transmission, LP ("Texas Eastern" or "TETCO") and Columbia Gas Transmission, LLC
13 ("Columbia"). Distribution also contracts for pipeline capacity on National Fuel Gas
14 Supply Corporation's ("Supply" or "NFGSC") transmission system. Supply's transmission
15 lines interconnect facilities of these pipelines with the Pennsylvania gas distribution lines
16 owned and operated by Distribution. Distribution uses this pipeline capacity to acquire
17 gas supplies at the lowest cost that is consistent with maintaining adequate, reliable and
18 reasonably continuous service.

19 Distribution's Pennsylvania Division also contracts for storage capacity in
20 Supply's substantial storage fields and storage capacity on Columbia. Distribution's
21 contracted storage service with Supply permits Distribution to obtain gas supplies at a
22 lower cost than would otherwise be the case. The storage fields enable Distribution to
23 maintain lower interstate pipeline entitlements than would be possible without storage
24 facilities. Distribution can rely upon gas withdrawn from storage, instead of current

1 pipeline deliveries, to meet a substantial portion of its customers' peak day and winter
2 requirements. Storage facilities also afford Distribution the flexibility to take advantage
3 of lower priced gas in the off-season.

4 Distribution's least cost procurement policy is explained in PGC Exhibit
5 8. Distribution capitalizes upon its judicious use of locally produced gas, its contracted
6 storage service, its diversified pipeline capacity and its portfolio of competitively priced
7 gas supply contracts to reduce its purchased gas costs to the lowest practical level that
8 is consistent with providing reliable service.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Statement to show actual retail sales for the twelve months ended November 2023 and projected retail sales for the twenty months ending July 2025.

Page 2 provides actual retail sales for the twelve months ended November 2023.
Pages 3 and 4 provide projected retail sales for the twenty months ending July 2025.

National Fuel Gas Distribution Corporation
Pennsylvania Division
Actual Retail Sales (Mcf)
Twelve Months Ended November 30, 2023

	Mcf
December 2022	2,855,267
January 2023	3,427,933
February 2023	3,192,847
March 2023	2,901,710
April 2023	2,174,149
May 2023	1,318,013
June 2023	590,444
July 2023	345,991
August 2023	326,640
September 2023	376,975
October 2023	616,679
November 2023	1,400,758
Total	19,527,404

National Fuel Gas Distribution Corporation
Pennsylvania Division
Projected Retail Sales (Mcf)
Eight Months Ended July 31, 2024

	Mcf
December 2023	2,799,328
January 2024	3,742,164
February 2024	3,909,889
March 2024	3,390,346
April 2024	2,476,675
May 2024	1,279,705
June 2024	647,700
July 2024	403,521
Total	18,649,329

National Fuel Gas Distribution Corporation
Pennsylvania Division
Projected Retail Sales (Mcf)
Twelve Months Ending July 31, 2025

	Mcf
August 2024	365,471
September 2024	375,657
October 2024	720,719
November 2024	1,608,593
December 2024	2,835,859
January 2025	3,789,541
February 2025	3,864,067
March 2025	3,392,281
April 2025	2,506,734
May 2025	1,295,104
June 2025	655,355
July 2025	408,371
Total	21,817,752

Company	Component	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Total
Columbia	Demand (D1)	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	13,984
	Demand (D2)	0	0	0	0	0	0	0	0	0
	Receipt Vol.	45,471	44,959	39,468	55,937	57,434	93,137	90,132	93,137	519,675
	Delivered Vol.	43,271	42,337	37,091	52,993	104,011	90,701	87,949	90,925	549,278
Texas Eastern	Demand (D1)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	80,000
	Demand (D2)	0	0	0	0	0	0	0	0	0
	Receipt Vol.	310,000	310,000	290,000	342,026	330,993	342,026	330,993	342,026	2,598,064
	Delivered Vol.	306,536	306,536	286,759	338,204	327,294	338,204	327,294	338,204	2,569,031
Tennessee	Demand (D1)	74,000	74,000	74,000	74,000	74,000	74,000	74,000	74,000	592,000
	Demand (D2)	0	0	0	0	0	0	0	0	0
	Receipt Vol.	1,271,875	1,387,500	1,297,984	699,871	1,661,976	1,717,375	1,258,019	1,238,358	10,532,958
	Delivered Vol.	1,251,354	1,365,114	1,277,042	688,579	1,635,161	1,689,666	1,237,722	1,218,378	10,363,016
Total Upstream Purchase Volumes		1,601,161	1,713,987	1,600,892	1,079,776	2,066,466	2,118,571	1,652,965	1,647,507	13,481,325
Total City Gate NFGSC Volumes		676,408	737,899	690,293	307,458	228,368	302,465	0	0	2,942,891
Total Storage Volumes		938,208	1,957,130	1,502,910	1,890,323	(387,426)	(1,237,660)	(1,215,356)	(1,256,732)	2,191,397
Total for NFGDC PAD		3,215,777	4,409,016	3,794,095	3,277,557	1,907,408	1,183,376	437,609	390,775	18,615,613

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Upstream Purchase & Delivered Volume (Dt)
For the Twelve Months Ending July 2024

Company	Component	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Total
Columbia	Demand (D1)	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	20,976
	Demand (D2)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Receipt Vol.	93,000	90,132	93,137	54,132	44,959	44,959	50,524	55,937	90,132	93,137	90,132	93,137	893,318
	Delivered Vol.	42,605	87,918	90,159	51,284	42,337	42,337	47,864	52,993	87,554	90,701	87,949	90,462	814,163
Texas Eastern	Demand (D1)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	120,000
	Demand (D2)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Receipt Vol.	342,026	330,993	342,026	330,993	313,100	313,100	282,800	342,026	330,993	342,026	330,993	342,026	3,943,102
	Delivered Vol.	338,204	327,294	338,204	327,294	309,601	309,601	279,640	338,204	327,294	338,204	327,294	338,204	3,899,038
Tennessee	Demand (D1)	74,000	74,000	74,000	74,000	74,000	74,000	74,000	74,000	74,000	74,000	74,000	74,000	888,000
	Demand (D2)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Receipt Vol.	1,141,693	1,190,168	1,717,375	664,835	1,271,875	1,387,500	1,298,658	843,843	1,642,940	1,717,375	1,227,173	1,218,714	15,322,149
	Delivered Vol.	1,123,273	1,170,965	1,689,666	654,109	1,251,354	1,365,114	1,277,705	830,228	1,616,433	1,689,666	1,207,374	1,199,050	15,074,937
Total Upstream Purchase Volumes		1,504,082	1,586,177	2,118,028	1,032,687	1,603,292	1,717,052	1,605,209	1,221,425	2,031,281	2,118,571	1,622,617	1,627,716	19,788,137
Total City Gate NFGSC Volumes		0	0	91,668	297,540	676,408	737,899	666,490	307,458	0	365,422	0	0	3,142,885
Total Storage Volumes		(1,104,776)	(1,187,005)	(1,073,412)	818,412	945,761	1,981,211	1,546,237	1,769,517	(87,901)	(1,262,354)	(1,217,989)	(1,227,112)	(99,411)
Total for NFGDC PAD		399,306	399,172	1,136,284	2,148,639	3,225,461	4,436,162	3,817,936	3,298,400	1,943,380	1,221,639	404,628	400,604	22,831,611

[illegible]

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Upstream Pipeline Rates (\$/Dt)
For the Twelve Months Ending July 2024

Company	Schedule	Component	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
NFGSC	EFT	Demand	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534
		Commodity	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237
	FG	Demand	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
		Commodity	30.3157	32.5935	30.3157	26.9013	17.7901	23.4824	22.3457	20.0679	25.7602	23.4824	25.7602	25.7602
Columbia	FTS	Demand	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237
		Commodity	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690
Columbia	SST	Demand	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146
		Commodity	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500
Texas Eastern	FT-1	Demand	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146
	CDS	Demand	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600
	STX-M2	Demand	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	ETX-M2	Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	ELA-M2	Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	WLA-M2	Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	M1-M2	Commodity	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	M2-M2	Commodity	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495
Tennessee	FTA-4 (0-4)	Demand	14.8017	14.8017	14.8017	14.8017	14.8017	14.8017	14.8017	14.8017	14.8017	14.8017	14.8017	14.8017
		Commodity	0.2600	0.2600	0.2600	0.2600	0.2600	0.2600	0.2600	0.2600	0.2600	0.2600	0.2600	0.2600
	FTA-4 (1-4)	Demand	12.6232	12.6232	12.6232	12.6232	12.6232	12.6232	12.6232	12.6232	12.6232	12.6232	12.6232	12.6232
		Commodity	0.2212	0.2212	0.2212	0.2212	0.2212	0.2212	0.2212	0.2212	0.2212	0.2212	0.2212	0.2212
	FTA-4 (4-4)	Demand	4.5022	4.5022	4.5022	4.5022	4.5022	4.5022	4.5022	4.5022	4.5022	4.5022	4.5022	4.5022
		Commodity	0.0449	0.0449	0.0449	0.0449	0.0449	0.0449	0.0449	0.0449	0.0449	0.0449	0.0449	0.0449
		Demand												
		Commodity												

Company	Component	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Total
Columbia	Demand (D1)	17,775	17,775	17,775	17,775	17,775	17,775	17,775	17,775	142,200
	Demand (D2)	553	553	517	553	0	0	0	0	2,175
	Gas Cost	122,071	132,159	113,833	149,599	140,196	211,192	199,195	214,081	1,282,326
	Transp. Cost	938	1,078	971	1,235	766	685	546	534	6,753
Tennessee	Demand (D1)	499,564	499,564	499,564	499,564	404,222	404,222	404,222	404,222	3,615,144
	Demand (D2)	59,830	59,830	55,970	59,830	0	0	0	0	235,460
	Gas Cost	3,790,390	4,430,148	4,035,072	2,044,715	4,148,292	4,134,580	2,839,978	2,939,243	28,362,419
	Transp. Cost	56,650	61,800	57,813	31,173	74,026	76,493	56,033	55,157	469,145
Texas Eastern	Demand (D1)	64,600	64,600	64,600	64,600	64,600	64,600	64,600	64,600	516,800
	Demand (D2)	0	0	0	3,100	0	0	0	0	3,100
	Gas Cost	933,488	933,488	873,263	893,276	748,375	705,429	669,433	719,452	6,476,202
	Transp. Cost	15,299	15,299	14,312	16,880	16,335	16,880	16,335	16,880	128,220
NFGSC	Demand (D1)	1,926,779	1,914,589	3,225,366	3,213,175	3,237,556	3,225,366	3,237,556	3,231,473	23,211,860
	Demand (D2)	59,024	59,024	55,216	47,399	0	0	0	0	220,663
	Gas Cost	2,109,677	2,495,037	2,259,099	940,908	594,291	760,128	0	0	9,159,140
	Transp. Cost	52,248	71,582	90,134	77,906	45,971	28,006	10,813	9,731	386,391
Total Purchase	Demand	<u>\$2,628,125</u>	<u>\$2,615,935</u>	<u>\$3,919,008</u>	<u>\$3,905,996</u>	<u>\$3,724,153</u>	<u>\$3,711,963</u>	<u>\$3,724,153</u>	<u>\$3,718,070</u>	<u>\$27,947,402</u>
	Commodity	<u>\$7,081,010</u>	<u>\$8,140,983</u>	<u>\$7,444,763</u>	<u>\$4,155,849</u>	<u>\$5,768,632</u>	<u>\$5,933,786</u>	<u>\$3,792,713</u>	<u>\$3,955,470</u>	<u>\$46,273,208</u>
PAD Storage Rental and Transp. Storage Gas	Demand	1,330,232	1,330,232	1,860,815	1,860,815	1,768,274	1,768,274	1,768,274	1,768,274	13,455,190
	Commodity	41,872	91,072	60,129	75,330	13,781	48,522	47,419	49,119	427,244
PAD Storage Gas	Demand	2,407,171	5,001,701	3,838,551	4,832,937	(979,351)	(3,129,386)	(3,072,818)	(3,177,377)	5,721,428
	Commodity	2,444,301	5,078,852	3,897,758	4,907,483	(994,457)	(3,177,655)	(3,120,214)	(3,226,388)	5,809,680
Total NFGDC PAD	Demand	6,365,528	8,947,868	9,618,374	10,599,748	4,513,076	2,350,851	2,419,609	2,308,967	47,124,020
	Commodity	9,567,183	13,310,907	11,402,650	9,138,662	4,787,956	2,804,653	719,918	778,201	52,510,132
	Total	<u>\$15,932,711</u>	<u>\$22,258,775</u>	<u>\$21,021,024</u>	<u>\$19,738,410</u>	<u>\$9,301,032</u>	<u>\$5,155,504</u>	<u>\$3,139,527</u>	<u>\$3,087,168</u>	<u>\$99,634,152</u>

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Upstream Purchase and Storage Cost
For the Twelve Months Ending July 2024

Note for next update - totals were not matching due to hidden cells, rows 15 to row 22.
TLW - 12/22/22

Company	Component	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Total
Columbia	Demand (D1)	17,775	17,775	17,775	17,775	17,775	17,775	17,775	17,775	17,775	17,775	17,775	17,775	213,300
	Demand (D2)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Gas Cost	221,619	173,098	171,225	136,716	143,452	172,439	194,572	197,325	284,231	264,323	270,126	292,404	2,521,531
	Transp. Cost	538	567	1,052	1,195	1,078	1,078	1,115	1,235	813	685	546	847	10,749
Tennessee	Demand (D1)	404,222	404,222	404,222	404,222	404,222	404,222	404,222	404,222	404,222	404,222	404,222	404,222	4,850,664
	Demand (D2)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Gas Cost	2,800,573	2,461,267	3,384,946	1,822,238	4,390,294	5,602,968	5,236,990	3,183,613	5,398,701	5,384,829	3,864,981	4,094,270	47,625,671
	Transp. Cost	50,852	53,011	76,493	29,612	56,650	61,800	57,843	37,585	73,178	76,493	54,659	54,282	682,458
Texas Eastern	Demand (D1)	64,600	64,600	64,600	64,600	64,600	64,600	64,600	64,600	64,600	64,600	64,600	64,600	775,200
	Demand (D2)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Gas Cost	729,541	564,509	534,758	769,636	994,875	1,237,997	1,115,222	1,222,823	951,936	915,946	909,238	1,046,429	10,992,909
	Transp. Cost	16,880	16,335	16,880	16,335	15,452	15,452	13,957	16,880	16,335	16,880	16,335	16,880	194,601
NFGSC	Demand (D1)	3,249,747	3,261,937	3,249,747	3,231,473	3,182,710	3,213,175	3,207,091	3,194,900	3,225,366	3,213,175	3,225,366	3,225,366	38,680,053
	Demand (D2)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Gas Cost	0	0	190,028	846,750	2,426,465	3,084,650	2,779,408	1,210,146	0	1,186,571	0	0	11,724,017
	Transp. Cost	9,733	9,733	27,209	50,915	76,911	105,386	90,707	78,414	46,272	28,201	10,885	9,793	544,159
Total Purchase	Demand	<u>\$3,736,344</u>	<u>\$3,748,534</u>	<u>\$3,736,344</u>	<u>\$3,718,070</u>	<u>\$3,669,307</u>	<u>\$3,699,772</u>	<u>\$3,693,688</u>	<u>\$3,681,497</u>	<u>\$3,711,963</u>	<u>\$3,699,772</u>	<u>\$3,711,963</u>	<u>\$3,711,963</u>	<u>\$44,519,217</u>
	Commodity	<u>\$3,830,179</u>	<u>\$3,278,951</u>	<u>\$4,403,036</u>	<u>\$3,673,829</u>	<u>\$8,105,623</u>	<u>\$10,282,215</u>	<u>\$9,490,216</u>	<u>\$5,948,466</u>	<u>\$6,771,897</u>	<u>\$7,874,372</u>	<u>\$5,127,201</u>	<u>\$5,515,349</u>	<u>\$74,301,334</u>
PAD Storage Rental and Transp. Storage Gas	Demand	1,768,274	1,768,274	1,860,815	1,860,815	1,860,815	1,860,815	1,860,815	1,860,815	1,768,274	1,768,274	1,768,274	1,768,274	21,774,534
	Commodity	45,169	46,371	42,022	32,075	37,646	78,656	61,544	70,353	3,017	49,721	47,807	48,471	562,852
PAD Storage Gas	Demand	(2,809,847)	(3,018,433)	(3,067,276)	2,322,241	2,743,411	5,695,125	4,444,183	5,083,515	(252,502)	(3,606,703)	(3,479,720)	(3,505,639)	548,355
	Commodity	(2,853,525)	(3,065,353)	(3,608,661)	2,732,125	3,227,632	6,700,335	5,228,597	5,980,774	(297,069)	(4,243,300)	(4,093,904)	(4,124,398)	1,583,253
Total NFGDC PAD	Demand	2,694,771	2,498,375	2,529,883	7,901,126	8,273,533	11,255,712	9,998,686	10,625,827	5,227,735	1,861,343	2,000,517	1,974,598	66,842,106
	Commodity	1,021,823	259,969	836,397	6,438,029	11,370,901	17,061,206	14,780,357	11,999,593	6,477,845	3,680,793	1,081,104	1,439,422	76,447,439
	Total	<u>\$3,716,594</u>	<u>\$2,758,344</u>	<u>\$3,366,280</u>	<u>\$14,339,155</u>	<u>\$19,644,434</u>	<u>\$28,316,918</u>	<u>\$24,779,043</u>	<u>\$22,625,420</u>	<u>\$11,705,580</u>	<u>\$5,542,136</u>	<u>\$3,081,621</u>	<u>\$3,414,020</u>	<u>\$143,289,545</u>

Storage Volume (Dt)			Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Total	
Col. - FSS	Storage Rental	Demand	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	147,336	
		Capacity	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	4,512,248	
		Injection	0	0	0	0	12,977	74,088	79,690	84,432	251,187	
	Storage Transp.	Withdrawal	189,693	84,605	28,202	112,806	0	0	0	0	415,306	
		Demand	18,417	18,417	18,417	18,417	9,209	9,209	9,209	9,209	110,504	
		Injection	0	0	0	0	3,770	74,088	79,690	84,432	241,980	
	Gas Cost	Withdrawal	185,649	82,801	27,600	110,401	0	0	0	0	406,451	
		Injection	0	0	0	0	(51,444)	(74,015)	(79,612)	(84,350)	(289,421)	
		Withdrawal	189,693	84,605	28,202	112,806	0	0	0	0	415,306	
	NFGSC - ESS	Storage Rental	Demand	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	1,500,504
Capacity			8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	70,040,800	
Injection			0	0	0	0	247,872	1,074,110	991,486	1,074,110	3,387,578	
Gas Cost		Withdrawal	691,676	1,561,384	1,337,808	1,652,477	0	0	0	0	5,243,345	
		Injection	0	0	0	0	(247,872)	(1,074,110)	(991,486)	(1,074,110)	(3,387,578)	
		Withdrawal	691,676	1,561,384	1,337,808	1,652,477	0	0	0	0	5,243,345	
NFGSC - FSS		Storage Rental	Demand	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	85,328
			Capacity	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	1,600,000
			Injection	0	0	0	0	26,000	0	66,366	13,634	106,000
		Gas Cost	Withdrawal	65,814	46,000	44,000	0	0	0	0	0	155,814
	Injection		0	0	0	0	(26,000)	0	(66,366)	(13,634)	(106,000)	
	Withdrawal		65,814	46,000	44,000	0	0	0	0	0	155,814	
NFGSC - FSS (New) Storage Rental	Storage Rental	Demand	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	112,000	
		Capacity	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	5,210,192	
		Injection	0	0	0	0	60,043	83,238	71,640	78,153	293,074	
	Gas Cost	Withdrawal	0	276,100	100,398	136,400	0	0	0	0	512,898	
		Injection	0	0	0	0	(60,043)	(83,238)	(71,640)	(78,153)	(293,074)	
		Withdrawal	0	276,100	100,398	136,400	0	0	0	0	512,898	

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Summary of Storage Volume (Dt)

Storage Volume (Dt)			Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Total
Col. - FSS	Storage Rental	Demand	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	221,004
		Capacity	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	6,768,372
		Injection	74,649	78,274	48,949	0	0	0	0	0	61,426	74,088	79,690	62,993	480,069
	Storage Transp.	Withdrawal	0	0	0	40,883	31,623	153,106	112,806	101,526	0	0	0	0	439,944
		Demand	9,209	9,209	18,417	18,417	18,417	18,417	18,417	18,417	9,209	9,209	9,209	9,209	165,756
		Injection	83,857	78,274	48,949	0	0	0	0	0	61,426	74,088	79,690	62,993	489,277
	Gas Cost	Withdrawal	0	0	0	50,049	20,911	149,842	110,401	99,361	0	0	0	0	430,564
		Injection	(36,121)	(78,197)	(48,904)	0	0	0	0	0	(62,394)	(74,015)	(79,612)	(62,712)	(441,955)
		Withdrawal	0	0	0	40,883	31,623	153,106	112,806	101,526	0	0	0	0	439,944
	NFGSC - ESS	Demand	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	2,250,756
	Storage Rental	Capacity	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	105,061,200
		Injection	991,486	1,074,110	991,486	0	0	0	0	0	0	1,086,475	1,002,900	1,086,475	6,232,932
		Withdrawal	0	0	0	742,540	919,325	1,671,499	1,253,625	1,587,924	0	0	0	0	6,174,913
	Gas Cost	Injection	(991,486)	(1,074,110)	(991,486)	0	0	0	0	0	0	(1,086,475)	(1,002,900)	(1,086,475)	(6,232,932)
		Withdrawal	0	0	0	742,540	919,325	1,671,499	1,253,625	1,587,924	0	0	0	0	6,174,913
	NFGSC - FSS	Demand	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	127,992
		Capacity	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	2,400,000
		Injection	0	16,000	34,000	0	0	0	0	0	0	24,695	64,707	598	140,000
	Gas Cost	Withdrawal	0	0	0	30,000	10,000	40,000	60,000	0	0	0	0	0	140,000
		Injection	0	(16,000)	(34,000)	0	0	0	0	0	0	(24,695)	(64,707)	(598)	(140,000)
		Withdrawal	0	0	0	30,000	10,000	40,000	60,000	0	0	0	0	0	140,000
	NFGSC - FSS (Ne Storage Rental)	Demand	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	168,000
		Capacity	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	7,815,288
		Injection	78,153	19,538	0	0	0	0	0	0	26,051	78,153	71,640	78,153	351,688
	Gas Cost	Withdrawal	0	0	0	0	0	130,255	130,255	91,178	0	0	0	0	351,688
		Injection	(78,153)	(19,538)	0	0	0	0	0	0	(26,051)	(78,153)	(71,640)	(78,153)	(351,688)
		Withdrawal	0	0	0	0	0	130,255	130,255	91,178	0	0	0	0	351,688

[illegible]

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Summary of Storage Unit Cost

Storage Unit Cost (\$/Dt)			Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
Col. - FSS	Storage Rental	Demand	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230
		Capacity	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513
		Injection	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153
		Withdrawal	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153
	Storage Transp.	Demand	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500
		Injection	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146
		Withdrawal	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180
	Gas Cost	Demand	2.5411	2.5411	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549
		Commodity	2.5806	2.5806	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588
NFGSC - ESS	Storage Rental	Demand	4.2337	4.2337	4.2337	4.2337	4.2337	4.2337	4.2337	4.2337	4.2337	4.2337	4.2337	4.2337
		Capacity	0.0748	0.0748	0.0748	0.0748	0.0748	0.0748	0.0748	0.0748	0.0748	0.0748	0.0748	0.0748
		Injection	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396
		Withdrawal	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396	0.0396
	Gas Cost	Demand	2.5411	2.5411	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549
		Commodity	2.5806	2.5806	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588
NFGSC - FSS	Storage Rental	Demand	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694
		Capacity	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713	0.0713
		Injection	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381
		Withdrawal	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381
	Gas Cost	Demand	2.5411	2.5411	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549
		Commodity	2.5806	2.5806	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588
NFGSC - FSS (N Storage Rental)	Storage Rental	Demand	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694	4.0694
		Capacity	0.0479	0.0479	0.0479	0.0479	0.0479	0.0479	0.0479	0.0479	0.0479	0.0479	0.0479	0.0479
		Injection	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453
		Withdrawal	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453	0.0453
	Gas Cost	Demand	2.5411	2.5411	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549	2.8549
		Commodity	2.5806	2.5806	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588	3.3588

Storage Cost (\$)			Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Total	
Col. - FSS	Storage Rental	Demand	51,991	51,991	51,991	51,991	51,991	51,991	51,991	51,991	415,928	
		Capacity	28,935	28,935	28,935	28,935	28,935	28,935	28,935	28,935	231,480	
		Injection	0	0	0	0	199	1,134	1,219	1,292	3,844	
	Storage Transp.	Withdrawal	2,902	1,294	431	1,726	0	0	0	0	6,353	
		Demand	185,091	185,091	185,091	185,091	92,550	92,550	92,550	92,550	1,110,564	
		Injection	0	0	0	0	55	1,082	1,163	1,233	3,533	
	Injection	Withdrawal	3,342	1,490	497	1,987	0	0	0	0	7,316	
		Demand	0	0	0	0	(130,740)	(188,102)	(202,326)	(214,367)	(735,535)	
		Commodity	0	0	0	0	(132,756)	(191,003)	(205,447)	(217,674)	(746,880)	
	Withdrawal	Demand	482,086	215,015	71,673	286,685	0	0	0	0	1,055,459	
		Commodity	489,522	218,332	72,778	291,107	0	0	0	0	1,071,739	
NFGSC - ESS	Storage Rental	Demand	518,480	518,480	794,085	794,085	794,085	794,085	794,085	794,085	5,801,470	
		Capacity	439,506	439,506	654,881	654,881	654,881	654,881	654,881	654,881	4,808,298	
		Injection	0	0	0	0	9,816	42,535	39,263	42,535	134,149	
	Injection	Withdrawal	32,647	73,697	52,977	65,438	0	0	0	0	224,759	
		Demand	0	0	0	0	(629,942)	(2,729,743)	(2,519,763)	(2,729,743)	(8,609,191)	
		Commodity	0	0	0	0	(639,658)	(2,771,848)	(2,558,629)	(2,771,848)	(8,741,983)	
	Withdrawal	Demand	1,757,825	3,968,101	3,399,905	4,199,605	0	0	0	0	13,325,436	
		Commodity	1,784,939	4,029,308	3,452,347	4,264,382	0	0	0	0	13,530,976	
	NFGSC - FSS	Storage Rental	Demand	28,303	28,303	43,404	43,404	43,404	43,404	43,404	43,404	317,030
			Capacity	9,580	9,580	14,260	14,260	14,260	14,260	14,260	14,260	104,720
			Injection	0	0	0	0	991	0	2,529	519	4,039
Injection		Withdrawal	2,981	2,084	1,676	0	0	0	0	0	6,741	
		Demand	0	0	0	0	(66,076)	0	(168,663)	(34,649)	(269,388)	
		Commodity	0	0	0	0	(67,096)	0	(171,264)	(35,184)	(273,544)	
Withdrawal		Demand	167,260	116,904	111,822	0	0	0	0	0	395,986	
		Commodity	169,840	118,708	113,546	0	0	0	0	0	402,094	
NFGSC - FSS (Net)		Storage Rental	Demand	37,150	37,150	56,972	56,972	56,972	56,972	56,972	56,972	416,132
			Capacity	31,196	31,196	31,196	31,196	31,196	31,196	31,196	31,196	249,568
			Injection	0	0	0	0	2,720	3,771	3,245	3,540	13,276
	Injection	Withdrawal	0	12,507	4,548	6,179	0	0	0	0	23,234	
		Demand	0	0	0	0	(152,593)	(211,541)	(182,066)	(198,618)	(744,818)	
		Commodity	0	0	0	0	(154,947)	(214,804)	(184,874)	(201,682)	(756,307)	
	Withdrawal	Demand	0	701,681	255,151	346,647	0	0	0	0	1,303,479	
		Commodity	0	712,504	259,087	351,994	0	0	0	0	1,323,585	
	Total Cost			\$6,223,576	\$11,501,857	\$9,657,253	\$11,676,565	(\$191,753)	(\$4,490,245)	(\$4,377,339)	(\$4,586,372)	\$25,413,542
	Summary	Storage Rental	Demand	\$1,145,141	\$1,145,141	\$1,675,724	\$1,675,724	\$1,675,724	\$1,675,724	\$1,675,724	\$1,675,724	\$12,344,626
			Commodity	\$38,530	\$89,582	\$59,632	\$73,343	\$13,726	\$47,440	\$46,256	\$47,886	\$416,395
Storage Transp.		Demand	\$185,091	\$185,091	\$185,091	\$185,091	\$92,550	\$92,550	\$92,550	\$92,550	\$1,110,564	
		Commodity	\$3,342	\$1,490	\$497	\$1,987	\$55	\$1,082	\$1,163	\$1,233	\$10,849	
Gas Cost		Demand	\$2,407,171	\$5,001,701	\$3,838,551	\$4,832,937	(\$979,351)	(\$3,129,386)	(\$3,072,818)	(\$3,177,377)	\$5,721,428	
		Commodity	\$2,444,301	\$5,078,852	\$3,897,758	\$4,907,483	(\$994,457)	(\$3,177,655)	(\$3,120,214)	(\$3,226,388)	\$5,809,680	
Total Cost		\$6,223,576	\$11,501,857	\$9,657,253	\$11,676,565	(\$191,753)	(\$4,490,245)	(\$4,377,339)	(\$4,586,372)	\$25,413,542		

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Summary of Storage Cost

Storage Cost (\$)			Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Total
Col. - FSS	Storage Rental	Demand	51,991	51,991	51,991	51,991	51,991	51,991	51,991	51,991	51,991	51,991	51,991	51,991	623,892
		Capacity	28,935	28,935	28,935	28,935	28,935	28,935	28,935	28,935	28,935	28,935	28,935	28,935	347,220
		Injection	1,142	1,198	749	0	0	0	0	0	940	1,134	1,219	964	7,346
	Storage Transp.	Withdrawal	0	0	0	626	484	2,343	1,726	1,553	0	0	0	0	6,732
		Demand	92,550	92,550	185,091	185,091	185,091	185,091	185,091	185,091	92,550	92,550	92,550	92,550	1,665,846
		Injection	1,224	1,143	715	0	0	0	0	0	897	1,082	1,163	920	7,144
	Injection	Withdrawal	0	0	0	901	376	2,697	1,987	1,788	0	0	0	0	7,749
		Demand	(91,787)	(198,706)	(139,616)	0	0	0	0	0	(178,129)	(211,305)	(227,284)	(179,036)	(1,225,863)
		Commodity	(93,214)	(201,795)	(164,259)	0	0	0	0	0	(209,569)	(248,602)	(267,401)	(210,637)	(1,395,477)
	Withdrawal	Demand	0	0	0	116,717	90,281	437,102	322,050	289,847	0	0	0	0	1,255,997
		Commodity	0	0	0	137,318	106,215	514,252	378,893	341,006	0	0	0	0	1,477,684
NFGSC - ESS	Storage Rental	Demand	794,085	794,085	794,085	794,085	794,085	794,085	794,085	794,085	794,085	794,085	794,085	794,085	9,529,020
		Capacity	654,881	654,881	654,881	654,881	654,881	654,881	654,881	654,881	654,881	654,881	654,881	654,881	7,858,572
		Injection	39,263	42,535	39,263	0	0	0	0	0	0	43,024	39,715	43,024	246,824
	Injection	Withdrawal	0	0	0	29,405	36,405	66,191	49,644	62,882	0	0	0	0	244,527
		Demand	(2,519,465)	(2,729,421)	(2,830,593)	0	0	0	0	0	0	(3,101,777)	(2,863,179)	(3,101,777)	(17,146,212)
		Commodity	(2,558,629)	(2,771,848)	(3,330,203)	0	0	0	0	0	0	(3,649,252)	(3,368,541)	(3,649,252)	(19,327,725)
	Withdrawal	Demand	0	0	0	2,119,877	2,624,581	4,771,962	3,578,974	4,533,364	0	0	0	0	17,628,758
		Commodity	0	0	0	2,494,043	3,087,829	5,614,231	4,210,676	5,333,519	0	0	0	0	20,740,298
NFGSC - FSS	Storage Rental	Demand	43,404	43,404	43,404	43,404	43,404	43,404	43,404	43,404	43,404	43,404	43,404	43,404	520,848
		Capacity	14,260	14,260	14,260	14,260	14,260	14,260	14,260	14,260	14,260	14,260	14,260	14,260	171,120
		Injection	0	610	1,295	0	0	0	0	0	0	941	2,465	23	5,334
	Injection	Withdrawal	0	0	0	1,143	381	1,524	2,286	0	0	0	0	0	5,334
		Demand	0	(40,658)	(97,067)	0	0	0	0	0	0	(70,502)	(184,732)	(1,707)	(394,666)
		Commodity	0	(41,290)	(114,199)	0	0	0	0	0	0	(82,946)	(217,338)	(2,009)	(457,782)
	Withdrawal	Demand	0	0	0	85,647	28,549	114,196	171,294	0	0	0	0	0	399,686
		Commodity	0	0	0	100,764	33,588	134,352	201,528	0	0	0	0	0	470,232
NFGSC - FSS (New)	Storage Rental	Demand	56,972	56,972	56,972	56,972	56,972	56,972	56,972	56,972	56,972	56,972	56,972	56,972	683,664
		Capacity	31,196	31,196	31,196	31,196	31,196	31,196	31,196	31,196	31,196	31,196	31,196	31,196	374,352
		Injection	3,540	885	0	0	0	0	0	0	1,180	3,540	3,245	3,540	15,930
	Injection	Withdrawal	0	0	0	0	0	5,901	5,901	4,130	0	0	0	0	15,932
		Demand	(198,595)	(49,648)	0	0	0	0	0	0	(74,373)	(223,119)	(204,525)	(223,119)	(973,379)
		Commodity	(201,682)	(50,420)	0	0	0	0	0	0	(87,500)	(262,500)	(240,624)	(262,500)	(1,105,226)
	Withdrawal	Demand	0	0	0	0	0	371,865	371,865	260,304	0	0	0	0	1,004,034
		Commodity	0	0	0	0	0	437,500	437,500	306,249	0	0	0	0	1,181,249
Summary	Storage Rental	Demand	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	1,675,724	20,108,688
		Commodity	\$43,945	\$45,228	\$41,307	\$31,174	\$37,270	\$75,959	\$59,557	\$68,565	\$2,120	\$48,639	\$46,644	\$47,551	\$547,959
	Storage Transp.	Demand	\$92,550	\$92,550	\$185,091	\$185,091	\$185,091	\$185,091	\$185,091	\$185,091	\$92,550	\$92,550	\$92,550	\$92,550	\$1,665,846
		Commodity	\$1,224	\$1,143	\$715	\$901	\$376	\$2,697	\$1,987	\$1,788	\$897	\$1,082	\$1,163	\$920	\$14,893
	Gas Cost	Demand	(\$2,809,847)	(\$3,018,433)	(\$3,067,276)	\$2,322,241	\$2,743,411	\$5,695,125	\$4,444,183	\$5,083,515	(\$252,502)	(\$3,606,703)	(\$3,479,720)	(\$3,505,639)	\$548,355
		Commodity	(\$2,853,525)	(\$3,065,353)	(\$3,608,661)	\$2,732,125	\$3,227,632	\$6,700,335	\$5,228,597	\$5,980,774	(\$297,069)	(\$4,243,300)	(\$4,093,904)	(\$4,124,398)	\$1,583,253
	Total Cost		(3,849,929)	(4,269,141)	(4,773,100)	6,947,256	7,869,504	14,334,931	11,595,139	12,995,457	1,221,720	(6,032,008)	(5,757,543)	(5,813,292)	24,468,994

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Unit Storage Gas Cost (\$/Dt)
For the Twelve Months Ending September 2024

	Oct-23*	Nov-23*	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Total
<u>Unit Storage Demand Gas Cost (\$/Dt)</u>													
Upstream Purchased Gas Cost	\$2,462,681	\$2,470,796	\$2,628,125	\$2,615,935	\$3,919,008	\$3,905,996	\$3,724,153	\$3,711,963	\$3,724,153	\$3,718,070	\$3,736,344	\$3,748,534	\$40,365,757
Appalachian Gas Cost	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Local Production Gas Cost	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Storage Rental & Transp. Cost	\$1,066,510	\$1,069,129	\$1,330,232	\$1,330,232	\$1,860,815	\$1,860,815	\$1,768,274	\$1,768,274	\$1,768,274	\$1,768,274	\$1,768,274	\$1,768,274	\$19,127,377
Total Demand Cost	\$3,529,190	\$3,539,926	\$3,958,357	\$3,946,167	\$5,779,823	\$5,766,811	\$5,492,427	\$5,480,237	\$5,492,427	\$5,486,344	\$5,504,618	\$5,516,808	\$59,493,134
Less: Offsystem Sales Purchase	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Net Demand Cost	\$3,529,190	\$3,539,926	\$3,958,357	\$3,946,167	\$5,779,823	\$5,766,811	\$5,492,427	\$5,480,237	\$5,492,427	\$5,486,344	\$5,504,618	\$5,516,808	\$59,493,134
Total Receipt Volume (Dt)	2,214,916	1,507,679	2,318,398	2,495,511	2,331,920	1,416,886	2,289,419	2,466,556	1,687,904	1,682,573	1,585,771	1,620,053	23,617,586
Less: Total Shrinkage (Dt)	32,622	22,902	26,806	25,372	22,164	17,727	18,254	13,432	7,315	7,056	7,051	6,938	207,639
Less: Offsystem Sales Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Volume (Dt)	2,182,294	1,484,777	2,291,592	2,470,139	2,309,756	1,399,159	2,271,165	2,453,124	1,680,589	1,675,517	1,578,720	1,613,115	23,409,947
Unit Storage Demand Gas Cost													\$2.5414
<u>Unit Storage Commodity Gas Cost (\$/Dt)</u>													
Upstream Purchased Gas Cost	\$3,462,610	\$2,726,518	\$7,081,010	\$8,140,983	\$7,444,763	\$4,155,849	\$5,768,632	\$5,933,786	\$3,792,713	\$3,955,470	\$3,830,179	\$3,278,951	\$59,571,467
Appalachian Gas Cost	\$0	\$0	\$22,129	\$23,631	\$20,921	\$19,920	\$17,061	\$17,440	\$17,184	\$19,123	\$20,364	\$19,093	\$196,866
Local Production Gas Cost	\$23,464	\$29,131	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$52,596
Storage Rental & Transp. Cost	\$47,484	\$29,021	\$41,872	\$91,072	\$60,129	\$75,330	\$13,781	\$48,522	\$47,419	\$49,119	\$45,169	\$46,371	\$595,290
Total Commodity Cost	\$3,533,559	\$2,784,671	\$7,145,011	\$8,255,686	\$7,525,813	\$4,251,099	\$5,799,474	\$5,999,748	\$3,857,316	\$4,023,712	\$3,895,712	\$3,344,415	\$60,416,218
Less: Offsystem Sales Purchase	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Net Commodity Cost	\$3,533,559	\$2,784,671	\$7,145,011	\$8,255,686	\$7,525,813	\$4,251,099	\$5,799,474	\$5,999,748	\$3,857,316	\$4,023,712	\$3,895,712	\$3,344,415	\$60,416,218
Total Receipt Volume (Dt)	2,214,916	1,507,679	2,318,398	2,495,511	2,331,920	1,416,886	2,289,419	2,466,556	1,687,904	1,682,573	1,585,771	1,620,053	23,617,586
Less: Total Shrinkage (Dt)	32,622	22,902	26,806	25,372	22,164	17,727	18,254	13,432	7,315	7,056	7,051	6,938	207,639
Less: Offsystem Sales Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Volume (Dt)	2,182,294	1,484,777	2,291,592	2,470,139	2,309,756	1,399,159	2,271,165	2,453,124	1,680,589	1,675,517	1,578,720	1,613,115	23,409,947
Unit Storage Commodity Gas Cost (\$/Dt)													\$2.5806

* per Books.

National Fuel Gas Distribution Corporation
 Pennsylvania Division - 1307(f) 2024
 Unit Storage Gas Cost (\$/Dt)
 For the Twelve Months Ending September 2025

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Total
<u>Unit Storage Demand Gas Cost (\$/Dt)</u>													
Upstream Purchased Gas Cost	\$3,736,344	\$3,718,070	\$3,669,307	\$3,699,772	\$3,693,688	\$3,681,497	\$3,711,963	\$3,699,772	\$3,711,963	\$3,711,963	\$3,730,236	\$3,742,427	\$44,507,002
Appalachian Gas Cost	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Local Production Gas Cost	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Storage Rental & Transp. Cost	\$1,860,815	\$1,860,815	\$1,860,815	\$1,860,815	\$1,860,815	\$1,860,815	\$1,768,274	\$1,768,274	\$1,768,274	\$1,768,274	\$1,768,274	\$1,768,274	\$21,774,534
Total Demand Cost	\$5,597,159	\$5,578,885	\$5,530,122	\$5,560,587	\$5,554,503	\$5,542,312	\$5,480,237	\$5,468,046	\$5,480,237	\$5,480,237	\$5,498,510	\$5,510,701	\$66,281,536
Less: Offsystem Sales Purchase	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Net Demand Cost	\$5,597,159	\$5,578,885	\$5,530,122	\$5,560,587	\$5,554,503	\$5,542,312	\$5,480,237	\$5,468,046	\$5,480,237	\$5,480,237	\$5,498,510	\$5,510,701	\$66,281,536
Total Receipt Volume (Dt)	1,620,053	2,254,016	1,358,720	2,320,986	2,498,611	2,312,158	1,560,858	2,072,825	2,530,033	1,657,058	1,662,929	1,551,395	23,399,642
Less: Total Shrinkage (Dt)	13,153	15,050	22,403	27,416	24,676	18,568	19,685	13,500	7,340	7,077	7,077	6,962	182,907
Less: Offsystem Sales Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Volume (Dt)	1,606,900	2,238,966	1,336,317	2,293,570	2,473,935	2,293,590	1,541,173	2,059,325	2,522,693	1,649,981	1,655,852	1,544,433	23,216,735
Unit Storage Demand Gas Cost													\$2.8549
<u>Unit Storage Commodity Gas Cost (\$/Dt)</u>													
Upstream Purchased Gas Cost	\$4,403,036	\$3,673,829	\$8,105,623	\$10,282,215	\$9,490,216	\$5,948,466	\$6,771,897	\$7,874,372	\$5,127,201	\$5,515,349	\$5,122,542	\$4,786,702	\$77,101,447
Appalachian Gas Cost	\$20,074	\$23,009	\$27,488	\$31,597	\$27,820	\$27,759	\$23,675	\$24,528	\$25,436	\$28,230	\$28,700	\$28,449	\$316,765
Local Production Gas Cost	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Storage Rental & Transp. Cost	\$42,022	\$32,075	\$37,646	\$78,656	\$61,544	\$70,353	\$3,017	\$49,721	\$47,807	\$48,471	\$44,341	\$46,860	\$562,513
Total Commodity Cost	\$4,465,132	\$3,728,913	\$8,170,757	\$10,392,468	\$9,579,580	\$6,046,578	\$6,798,589	\$7,948,621	\$5,200,444	\$5,592,050	\$5,195,583	\$4,862,011	\$77,980,725
Less: Offsystem Sales Purchase	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Net Commodity Cost	\$4,465,132	\$3,728,913	\$8,170,757	\$10,392,468	\$9,579,580	\$6,046,578	\$6,798,589	\$7,948,621	\$5,200,444	\$5,592,050	\$5,195,583	\$4,862,011	\$77,980,725
Total Receipt Volume (Dt)	1,620,053	2,254,016	1,358,720	2,320,986	2,498,611	2,312,158	1,560,858	2,072,825	2,530,033	1,657,058	1,662,929	1,551,395	23,399,642
Less: Total Shrinkage (Dt)	13,153	15,050	22,403	27,416	24,676	18,568	19,685	13,500	7,340	7,077	7,077	6,962	182,907
Less: Offsystem Sales Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Volume (Dt)	1,606,900	2,238,966	1,336,317	2,293,570	2,473,935	2,293,590	1,541,173	2,059,325	2,522,693	1,649,981	1,655,852	1,544,433	23,216,735
Unit Storage Commodity Gas Cost (\$/Dt)													\$3.3588

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Summary of Appalachian & Local Production Cost

Revenue Month	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24
<u>NFGSC</u>												
Appalachian - PA (Dt)	9,052	9,052	8,468	9,052	8,760	9,052	8,760	9,052	9,052	8,760	9,052	8,760
Appalachian - PA (Mcf)	8,613	8,613	8,057	8,613	8,335	8,613	8,335	8,613	8,613	8,335	8,613	8,335
Amount (\$)	\$22,129	\$23,631	\$20,921	\$19,920	\$17,061	\$17,440	\$17,184	\$19,123	\$20,364	\$19,093	\$20,074	\$23,009
EFT Shrinkage (Dt)	74	74	69	74	72	74	72	74	74	72	74	72
EFT Shrinkage (Mcf)	71	71	66	71	68	71	68	71	71	68	71	68
<u>NFGDC</u>												
Appalachian - PA (Dt)	8,978	8,978	8,399	8,978	8,688	8,978	8,688	8,978	8,978	8,688	8,978	8,688
Appalachian - PA (Mcf)	8,542	8,542	7,991	8,542	8,267	8,542	8,267	8,542	8,542	8,267	8,542	8,267
Amount (\$)	\$22,129	\$23,631	\$20,921	\$19,920	\$17,061	\$17,440	\$17,184	\$19,123	\$20,364	\$19,093	\$20,074	\$23,009
<u>NFGDC</u>												
Local Production - PA (Dt)	0	0	0	0	0	0	0	0	0	0	0	0
Local Production - PA (Mcf)	0	0	0	0	0	0	0	0	0	0	0	0
Amount (\$)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<u>NFGDC</u>												
Total PA (Dt)	8,978	8,978	8,399	8,978	8,688	8,978	8,688	8,978	8,978	8,688	8,978	8,688
Total PA (Mcf)	8,542	8,542	7,991	8,542	8,267	8,542	8,267	8,542	8,542	8,267	8,542	8,267
Total Amount (\$)	\$22,129	\$23,631	\$20,921	\$19,920	\$17,061	\$17,440	\$17,184	\$19,123	\$20,364	\$19,093	\$20,074	\$23,009

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Summary of Appalachian & Local Production Cost

Revenue Month	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25
<u>NFGSC</u>												
Appalachian - PA (Dt)	9,052	9,052	8,176	9,052	8,760	9,052	8,760	9,052	9,052	8,760	9,052	9,052
Appalachian - PA (Mcf)	8,613	8,613	7,779	8,613	8,335	8,613	8,335	8,613	8,613	8,335	8,613	8,613
Amount (\$)	\$27,488	\$31,597	\$27,820	\$27,759	\$23,675	\$24,528	\$25,436	\$28,230	\$28,700	\$28,449	\$29,524	\$31,968
EFT Shrinkage (Dt)	74	74	67	74	72	74	72	74	74	72	74	74
EFT Shrinkage (Mcf)	71	71	64	71	68	71	68	71	71	68	71	71
<u>NFGDC</u>												
Appalachian - PA (Dt)	8,978	8,978	8,109	8,978	8,688	8,978	8,688	8,978	8,978	8,688	8,978	8,978
Appalachian - PA (Mcf)	8,542	8,542	7,715	8,542	8,267	8,542	8,267	8,542	8,542	8,267	8,542	8,542
Amount (\$)	\$27,488	\$31,597	\$27,820	\$27,759	\$23,675	\$24,528	\$25,436	\$28,230	\$28,700	\$28,449	\$29,524	\$31,968
<u>NFGDC</u>												
Local Production - PA (Dt)	0	0	0	0	0	0	0	0	0	0	0	0
Local Production - PA (Mcf)	0	0	0	0	0	0	0	0	0	0	0	0
Amount (\$)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<u>NFGDC</u>												
Total PA (Dt)	8,978	8,978	8,109	8,978	8,688	8,978	8,688	8,978	8,978	8,688	8,978	8,978
Total PA (Mcf)	8,542	8,542	7,715	8,542	8,267	8,542	8,267	8,542	8,542	8,267	8,542	8,542
Total Amount (\$)	\$27,488	\$31,597	\$27,820	\$27,759	\$23,675	\$24,528	\$25,436	\$28,230	\$28,700	\$28,449	\$29,524	\$31,968

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Pricing of Appalachian & Local Production - Dt

Revenue Month	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24
Appalachian - PA (Dt)	9,052	9,052	8,468	9,052	8,760	9,052	8,760	9,052	9,052	8,760	9,052	8,760
Vol. @ Production Rate 1	9,052	9,052	8,468	9,052	8,760	9,052	8,760	9,052	9,052	8,760	9,052	8,760
Supply Production Rate 1	\$2.4446	\$2.6106	\$2.4706	\$2.2006	\$1.9476	\$1.9266	\$1.9616	\$2.1126	\$2.2496	\$2.1796	\$2.2176	\$2.6266
<u>Amount</u>												
@ Production Rate 1	\$22,129	\$23,631	\$20,921	\$19,920	\$17,061	\$17,440	\$17,184	\$19,123	\$20,364	\$19,093	\$20,074	\$23,009
Total Appalachian	\$22,129	\$23,631	\$20,921	\$19,920	\$17,061	\$17,440	\$17,184	\$19,123	\$20,364	\$19,093	\$20,074	\$23,009

Revenue Month	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24
Local Production - PA (Dt)	0	0	0	0	0	0	0	0	0	0	0	0
Vol. @ Production Rate 1	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Production Rate 1	\$2.207	\$2.373	\$2.233	\$1.963	\$1.710	\$1.689	\$1.724	\$1.875	\$2.012	\$1.942	\$1.980	\$2.389
<u>Amount</u>												
@ Production Rate 1	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0

National Fuel Gas Distribution Corporation
Pennsylvania Division - 1307(f) 2024
Pricing of Appalachian & Local Production

Revenue Month	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25
Appalachian - PA (Dt)	9,052	9,052	8,176	9,052	8,760	9,052	8,760	9,052	9,052	8,760	9,052	9,052
Vol. @ Production Rate 1	9,052	9,052	8,176	9,052	8,760	9,052	8,760	9,052	9,052	8,760	9,052	9,052
Supply Production Rate 1	\$3.0366	\$3.4906	\$3.4026	\$3.0666	\$2.7026	\$2.7096	\$2.9036	\$3.1186	\$3.1706	\$3.2476	\$3.2616	\$3.5316
Amount												
@ Production Rate 1	\$27,488	\$31,597	\$27,820	\$27,759	\$23,675	\$24,528	\$25,436	\$28,230	\$28,700	\$28,449	\$29,524	\$31,968
Total Appalachian	\$27,488	\$31,597	\$27,820	\$27,759	\$23,675	\$24,528	\$25,436	\$28,230	\$28,700	\$28,449	\$29,524	\$31,968

Revenue Month	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25
Local Production - PA (Dt)	0	0	0	0	0	0	0	0	0	0	0	0
Vol. @ Production Rate 1	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Production Rate 1	\$2.7989	\$3.2529	\$3.1649	\$2.8289	\$2.4649	\$2.4719	\$2.6659	\$2.8809	\$2.9329	\$3.0099	\$3.0239	\$3.2939
Amount												
@ Production Rate 1	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
@ Production Rate 2	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0

National Fuel Gas Distribution Corporation
1307(f) 2024 Filing
Upstream Pipeline Rates

Pipeline	Service	Component	12/1/2023	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024
Columbia	FTS	Reservation	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748
		Reservation Rate	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690
		Commodity - base	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132
		Commodity - ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Commodity - Total	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146
		Fuel Retention	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%
	SST	Reservation	18,417	18,417	18,417	18,417	9,209	9,209	9,209	9,209	9,209	9,209	18,417
		Reservation Rate	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500
		Inj. Commodity-base	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132
		Inj. Commodity-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Inj. Commodity-Total	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146
		Withdr. Commodity	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180
		Fuel Retention	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%
	FSS	Reservation	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417
		Capacity	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031
		Reservation Rate	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230
		Capacity Rate	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513
		Injection Rate	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153
		Withdrawal Rate	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153
		Fuel Retention	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%

Notes: (latest rates)

1. V1 - FTS Rates - Version 85.0.0 updated
2. V8 - SST Rates - Version 85.0.0 updated
3. V9 - FSS Rates - Version 10.0.0
4. V17 - Retainage Rates - Version 16.0.0

National Fuel Gas Distribution Corporation
1307(f) 2024 Filing
Upstream Pipeline Rates

Pipeline	Service	Component	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025
Columbia	FTS	Reservation	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748
		Reservation Rate	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690	\$10.1690
		Commodity - base	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132
		Commodity - ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Commodity - Total	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146
		Fuel Retention	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%
	SST	Reservation	18,417	18,417	18,417	18,417	18,417	9,209	9,209	9,209	9,209	9,209	9,209	18,417
		Reservation Rate	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500	\$10.0500
		Inj. Commodity-base	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132
		Inj. Commodity-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Inj. Commodity-Total	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146	\$0.0146
		Withdr. Commodity	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180	\$0.0180
		Fuel Retention	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%	2.132%
	FSS	Reservation	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417	18,417
		Capacity	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031	564,031
		Reservation Rate	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230	\$2.8230
		Capacity Rate	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513	\$0.0513
		Injection Rate	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153
		Withdrawal Rate	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153	\$0.0153
		Fuel Retention	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%

Notes: (latest rates)

1. V1 - FTS Rates - Version 85.0.0 updated
2. V8 - SST Rates - Version 85.0.0 updated
3. V9 - FSS Rates - Version 10.0.0
4. V17 - Retainage Rates - Version 16.0.0

National Fuel Gas Distribution Corporation
1307(f) 2024 Filing
Upstream Pipeline Rates

Pipeline	Service	Component	12/1/2023	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024
Texas Eastern	FT-1 Reservation Volumes	Demand (STX)	0	0	0	0	0	0	0	0	0	0	0
		Demand (WLA)	0	0	0	0	0	0	0	0	0	0	0
		Demand (ELA)	0	0	0	0	0	0	0	0	0	0	0
		Demand (ETX)	0	0	0	0	0	0	0	0	0	0	0
		Demand (M1 - M2)	0	0	0	0	0	0	0	0	0	0	0
		Demand (M2 - M2)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	FT-1 Reservation Rates	Demand (STX)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (WLA)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (ELA)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (ETX)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (M1- M2)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (M2 - M2)	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600
	Commodity Base	STX-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		WLA-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		ELA-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		ETX-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		M1-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		M2-M2	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481
		ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
	Commodity Total	STX-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		WLA-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		ELA-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		ETX-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		M1-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		M2-M2	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495
	Shrinkage	STX-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		WLA-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		ELA-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		ETX-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		M1-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		M2-M2	0.46%	0.46%	0.46%	0.46%	0.33%	0.33%	0.33%	0.33%	0.33%	0.33%	0.33%

Notes: (latest rates)

1. Part 4 Statements of Rates - 2. Rate Sch. FT-1 - Version 117.0 Page 1
2. Part 4 Statements of Rates - 2. Rate Sch. FT-1 - Version 117.0 Page 2
3. Part 4 Statements of Rates - 16. Percentages for Applicable Shrinkage - Version 20.0 Page 3
4. Part 4 Statements of Rates - 16. Percentages for Applicable Shrinkage - Version 20.0 Page 5

National Fuel Gas Distribution Corporation
1307(f) 2024 Filing
Upstream Pipeline Rates

Pipeline	Service	Component	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025
Texas Eastern	FT-1 Reservation Volumes	Demand (STX)	0	0	0	0	0	0	0	0	0	0	0	0
		Demand (WLA)	0	0	0	0	0	0	0	0	0	0	0	0
		Demand (ELA)	0	0	0	0	0	0	0	0	0	0	0	0
		Demand (ETX)	0	0	0	0	0	0	0	0	0	0	0	0
		Demand (M1 - M2)	0	0	0	0	0	0	0	0	0	0	0	0
		Demand (M2 - M2)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	FT-1 Reservation Rates	Demand (STX)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (WLA)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (ELA)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (ETX)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (M1- M2)	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		Demand (M2 - M2)	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600	\$6.4600
	Commodity Base	STX-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		WLA-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		ELA-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		ETX-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		M1-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		M2-M2	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481	\$0.0481
		ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
	Commodity Total	STX-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		WLA-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		ELA-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		ETX-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		M1-M2	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
		M2-M2	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495	\$0.0495
	Shrinkage	STX-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		WLA-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		ELA-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		ETX-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		M1-M2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		M2-M2	0.33%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%

Notes: (latest rates)

1. Part 4 Statements of Rates - 2. Rate Sch. FT-1
2. Part 4 Statements of Rates - 2. Rate Sch. FT-1
3. Part 4 Statements of Rates - 16. Percentages for
4. Part 4 Statements of Rates - 16. Percentages for

National Fuel Gas Distribution Corporation
1307(f) 2024 Filing
Upstream Pipeline Rates

Pipeline	Service	Component	12/1/2023	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024
Tennessee	FTA-4 (0-4)	Reservation	11,147	11,147	11,147	11,147	0	0	0	0	0	0	0
		Reservation Rate	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017
		Commodity-base	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279
		Commodity-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Commodity-EPCR	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>
		Commodity-Total	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600
		Fuel Retention	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%
	FTA-4 (1-4)	Reservation	6,353	6,353	6,353	6,353	8,750	8,750	8,750	8,750	8,750	8,750	8,750
		Reservation Rate	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232
		Commodity-base	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941
		Commodity-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Commodity-EPCR	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>
		Commodity-Total	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212
		Fuel Retention	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%
	FTA-4 (4-4)	Reservation	56,500	56,500	56,500	56,500	65,250	65,250	65,250	65,250	65,250	65,250	65,250
		Reservation Rate	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022
		Commodity-base	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403
		Commodity-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Commodity-EPCR	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>
		Commodity-Total	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449
		Fuel Retention	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%

Notes:

1. Twenty Second Revised Sheet No.14
2. Twenty Fourth Revised Sheet No. 15
3. Twenty Second Revised Sheet No. 23
4. Twenty Fourth Revised Sheet No. 24

National Fuel Gas Distribution Corporation
1307(f) 2024 Filing
Upstream Pipeline Rates

Pipeline	Service	Component	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025
Tennessee	FTA-4 (0-4)	Reservation	0	0	0	0	0	0	0	0	0	0	0	0
		Reservation Rate	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017	\$14.8017
		Commodity-base	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279	\$0.2279
		Commodity-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Commodity-EPCR	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>	<u>\$0.0307</u>
		Commodity-Total	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600	\$0.2600
		Fuel Retention	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%
	FTA-4 (1-4)	Reservation	8,750	8,750	8,750	8,750	8,750	8,750	8,750	8,750	8,750	8,750	8,750	8,750
		Reservation Rate	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232	\$12.6232
		Commodity-base	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941	\$0.1941
		Commodity-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Commodity-EPCR	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>	<u>\$0.0257</u>
		Commodity-Total	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212	\$0.2212
		Fuel Retention	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%	3.39%
	FTA-4 (4-4)	Reservation	65,250	65,250	65,250	65,250	65,250	65,250	65,250	65,250	65,250	65,250	65,250	65,250
		Reservation Rate	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022	\$4.5022
		Commodity-base	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403	\$0.0403
		Commodity-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Commodity-EPCR	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>	<u>\$0.0032</u>
		Commodity-Total	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449
		Fuel Retention	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%

Notes:

1. Twenty Second Revised Sheet No.14
2. Twenty Fourth Revised Sheet No. 15
3. Twenty Second Revised Sheet No. 23
4. Twenty Fourth Revised Sheet No. 24

National Fuel Gas Distribution Corporation
1307(f) 2024 Filing
Upstream Pipeline Rates exclusive of GSR & Stranded Cost

Pipeline	Service	Component	12/1/2023	1/1/2024	<u>2/1/2024</u>	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024
NFGSC	EFT	Reservation	314,778	314,778	314,778	314,778	314,778	314,778	314,778	314,778	314,778	314,778	314,778
		Reservation Rate	\$5.1512	\$5.1512	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534
		Commodity-base	\$0.0148	\$0.0148	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223
		Commodity-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Commodity-Total	\$0.0162	\$0.0162	<u>\$0.0237</u>	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237
		Fuel Retention-base	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%
		Fuel Retention-LAUF	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>
		Fuel Retention-total	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%
	FT	Reservation	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000
		Reservation Rate	\$5.0076	\$5.0076	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827
		Commodity-base	\$0.0140	\$0.0140	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068
		Commodity-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Commodity-Total	\$0.0154	\$0.0154	<u>\$0.0082</u>	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082
		Fuel Retention-base	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%
		Fuel Retention-LAUF	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>
		Fuel Retention-total	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%
	FG	Reservation	5,352	5,352	5,352	5,352	5,352	5,352	5,352	5,352	5,352	5,352	5,352
		Reservation Rate	Exh23Scch3SH9	Exh23Scch3SH9	Exh23Scch3SH9	Exh23Scch3SH9	Exh23Scch3SH9	Exh23Scch3SH9	Exh23Scch3SH9	Exh23Scch3SH9	Exh23Scch3SH9	Exh23Scch3SH9	Exh23Scch3SH9
		Commodity-base	\$0.0148	\$0.0148	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223
		Commodity-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Commodity-Total	\$0.0162	\$0.0162	<u>\$0.0237</u>	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237
		Fuel Retention-base	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%
		Fuel Retention-LAUF	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>	<u>0.10%</u>
		Fuel Retention-total	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%
ESS		Reservation	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563
		Capacity	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100
		Reservation Rate	\$2.7643	\$2.7643	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337
		Capacity Rate	\$0.0502	\$0.0502	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748
		Injection Rate-base	\$0.0458	\$0.0458	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382
		Injection Rate-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Injection Rate-Total	\$0.0472	\$0.0472	<u>\$0.0396</u>	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396
		Withdrawal Rate-base	\$0.0458	\$0.0458	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382
		Withdrawal Rate-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Withdrawal Rate-Total	\$0.0472	\$0.0472	<u>\$0.0396</u>	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396
		Fuel Retention-LAUF	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%
	FSS	Reservation (19-day)	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666
		Capacity	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
		Reservation Rate	\$2.6536	\$2.6536	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694
		Capacity Rate	\$0.0479	\$0.0479	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713
		Injection Rate-base	\$0.0439	\$0.0439	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367
		Injection Rate-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Injection Rate-Total	\$0.0453	\$0.0453	<u>\$0.0381</u>	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381
		Withdrawal Rate-base	\$0.0439	\$0.0439	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367
		Withdrawal Rate-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
FSS		Reservation (63-day)	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
		Capacity	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274
		Reservation Rate	\$2.6536	\$2.6536	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694
		Capacity Rate	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479
		Injection Rate-base	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439
		Injection Rate-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Injection Rate-Total	\$0.0453	\$0.0453	<u>\$0.0453</u>	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453
		Withdrawal Rate-base	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439
		Withdrawal Rate-ACA	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>	<u>\$0.0014</u>
		Withdrawal Rate-Total	\$0.0453	\$0.0453	<u>\$0.0453</u>	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453
		Fuel Retention-LAUF	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%
	FST (Discount)	Reservation	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
		Capacity	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274
		Reservation Rate	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000

Notes:

1. Part 4 - Applicable Rates, Section 4.010 Transportation Rates - Version 39.0.0 - Updated 11/20/23
2. Part 4 - Applicable Rates, Section 4.020 Storage Rates - Version 32.0, Page 1 - Updated 11/20/23
3. Part 4 - Applicable Rates, Section 4.040 Gathering Rates - Version 35.0.0

National Fuel Gas Distribution Corporation
1307(f) 2024 Filing
Upstream Pipeline Rates exclusive of GSR & Stranded Cost

Pipeline	Service	Component	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025
NFGSC	EFT	Reservation	314,778	314,778	314,778	314,778	314,778	314,778	314,778	314,778	314,778	314,778	314,778	314,778
		Reservation Rate	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534	\$8.9534
		Commodity-base	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223
		Commodity-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Commodity-Total	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237
		Fuel Retention-base	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%
		Fuel Retention-LAUF	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
		Fuel Retention-total	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%
	FT	Reservation	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000	31,000
		Reservation Rate	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827	\$8.6827
		Commodity-base	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068	\$0.0068
		Commodity-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Commodity-Total	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082	\$0.0082
		Fuel Retention-base	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%
		Fuel Retention-LAUF	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
		Fuel Retention-total	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%
	FG	Reservation	5,352	5,352	5,352	5,352	5,352	5,352	5,352	5,352	5,352	5,352	5,352	5,352
		Reservation Rate	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9	Exh23Sch3SH9
		Commodity-base	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223	\$0.0223
		Commodity-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Commodity-Total	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237	\$0.0237
		Fuel Retention-base	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%
		Fuel Retention-LAUF	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
		Fuel Retention-total	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%
	ESS	Reservation	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563	187,563
		Capacity	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100	8,755,100
		Reservation Rate	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337	\$4.2337
		Capacity Rate	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748	\$0.0748
		Injection Rate-base	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382
		Injection Rate-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Injection Rate-Total	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396
		Withdrawal Rate-base	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382	\$0.0382
		Withdrawal Rate-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Withdrawal Rate-Total	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396	\$0.0396
		Fuel Retention-LAUF	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%
	FSS	Reservation (19-day)	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666	10,666
		Capacity	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
		Reservation Rate	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694
		Capacity Rate	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713	\$0.0713
		Injection Rate-base	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367
		Injection Rate-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Injection Rate-Total	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381
		Withdrawal Rate-base	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367	\$0.0367
		Withdrawal Rate-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Withdrawal Rate-Total	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381	\$0.0381
		Fuel Retention-LAUF	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%
	FSS	Reservation (63-day)	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
		Capacity	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274
		Reservation Rate	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694	\$4.0694
		Capacity Rate	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479	\$0.0479
		Injection Rate-base	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439
		Injection Rate-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Injection Rate-Total	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453
		Withdrawal Rate-base	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439	\$0.0439
		Withdrawal Rate-ACA	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014	\$0.0014
		Withdrawal Rate-Total	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453	\$0.0453
		Fuel Retention-LAUF	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%
	FST (Discount)	Reservation	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
		Capacity	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274	651,274
		Reservation Rate	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000

Notes:

1. Part 4 - Applicable Rates, Section 4.010 Transportation f
2. Part 4 - Applicable Rates, Section 4.020 Storage Rates -
3. Part 4 - Applicable Rates, Section 4.040 Gathering Rates

National Fuel Gas Distribution Corporation
Pennsylvania Division
Calculation of Firm Gathering Rate
\$/Dth
1307(f) 2024 Filing

Exhibit 23
Schedule 3
Page 9

Historical	Actual NYMEX ^(A)	Columbia Apalachian	Difference	%
	(1)	(2)	(3 = 2 - 1)	(4 = 3 / 1)
December 2022	\$6.3290	\$5.8900	(0.439)	0.9306
January 2023	\$6.0120	\$3.9600	(2.052)	0.6587
February	\$3.6110	\$2.4800	(1.131)	0.6868
March	\$2.4250	\$2.0800	(0.345)	0.8577
April	\$2.4580	\$1.7200	(0.738)	0.6998
May	\$2.1740	\$1.7700	(0.404)	0.8142
June	\$2.3070	\$1.5300	(0.777)	0.6632
July	\$2.4310	\$1.5900	(0.841)	0.6541
August	\$2.6480	\$1.3500	(1.298)	0.5098
September	\$2.6320	\$1.0800	(1.552)	0.4103
October	\$2.6820	\$1.3800	(1.302)	0.5145
November 2023	\$3.1010	\$1.9500	(1.151)	0.6288

Forecast	Projected NYMEX ^(B)	Forecasted Index Price	FG rate ^(C)
	(5)	(6 = 4 x 5)	(7)
December 2023			\$28.0379
January 2024	3.7180	2.45	25.7602
February	3.6480	2.51	25.7602
March	3.3510	2.87	23.4824
April	3.1300	2.19	28.0379
May	3.1480	2.56	25.7602
June	3.2550	2.16	28.0379
July	3.3680	2.20	26.9013
August	3.3980	1.73	30.3157
September	3.3770	1.39	32.5935
October	3.4520	1.78	30.3157
November	3.8080	2.39	26.9013
December	4.2510	3.96	17.7901
January 2025	4.5190	2.98	23.4824
February	4.4150	3.03	22.3457
March	4.0430	3.47	20.0679
April	3.6440	2.55	25.7602
May	3.6300	2.96	23.4824
June	3.7500	2.49	25.7602
July	3.8750	2.53	25.7602
August	3.9110	1.99	29.1746
September	3.8810	1.59	31.4524
October	3.9490	2.03	28.0379
November	4.2700	2.68	24.6235

(A) NYMEX Actual

(B) PGC Exhibit 25

(C) From FG Index Price table Part 4 - Applicable Rates, Section 4.040 Gathering Rates - Version 35.0

Summary of Modifications to
National Fuel Gas Distribution Corporation's
Transportation Service Rates

A) Background

Since August 1, 1993, National Fuel Gas Distribution Corporation ("Distribution") has included gas costs associated with providing imbalance services to its transportation customers within the transportation service rates that Distribution charges. Over the last thirty one Distribution 1307(f) proceedings (R-922499, R-932885, R-943207, R-953487, R-963779, R-974167, R-984497, R-994898, R-005832, R-016789, R-038101, R-049108, R-050216, R-061246 R-072043, R-2008-2012502, R-2009-2083181, R-2010-2150861, R-2011-2218386, R-2012-2281465, R-2013-2341534 R-2014-2399610, R-2015-2461373, R-2016-2521819, R-2017-2582461, R-2018-2641577, R-2019-3006858, R-2020-3015251, R-2021-3023541, R-2022-3030235, and 2023-3037428), the Commission has consistently recognized that transportation customers should be responsible for paying the costs of service which can be fairly determined as having been incurred for the benefit of transportation customers.

The Commission has determined that

1 transportation customers cause Distribution to incur
2 costs associated with storage and transportation
3 service contracted by Distribution with National Fuel
4 Gas Supply Corporation ("Supply"). Such costs have
5 been recovered from transportation customers through a
6 number of services offered to transportation customers
7 including: (1) Monthly Metered Transportation ("MMT")
8 charges, (2) overdelivery charges for Daily Metered
9 Transportation ("DMT") customers, (3) sales service to
10 MMT and DMT customers, and (4) the release of firm
11 capacity on Supply to transportation customers.

12 The allocation of purchased gas costs to
13 transportation customers, as well as the design of
14 transportation rates, are explained in greater detail
15 below.

16 B) Purchased Gas Costs Associated
17 with Transportation Service
18

19 Purchased gas costs associated with
20 transportation service relate to the costs incurred by
21 Distribution in order to support the differences
22 between what transportation customers use on a daily
23 basis and what the transportation customers deliver to
24 Distribution's system on a daily basis.

25 In the previous 1307(f) proceedings

1 addressing the issue, the Commission recognized that
2 the Federal Energy Regulatory Commission's ("FERC")
3 Order 636 imposed additional costs on Distribution in
4 order to provide MMT and DMT transportation services.
5 Distribution determined the level of additional costs
6 after a review of Distribution's design peak day
7 requirements and supply sources. The term "design
8 peak day" refers to the practice that is standard in
9 the natural gas industry under which pipeline
10 capacity, storage capacity and natural gas supply
11 planning are based upon customers' requirements on the
12 coldest winter day reasonably expected to be
13 experienced. For this proceeding, Distribution has
14 updated this review for the design peak day
15 requirements forecasted during the twelve months
16 ending July 2025. This updated review has lead to the
17 conclusion that Distribution requires that 157,902
18 Mcf of gas be delivered into its system to meet MMT
19 and DMT transportation service customers' design peak
20 day (at 74 heating degree days) requirements, but only
21 122,156 Mcf are delivered on that day. This
22 difference, 35,746 Mcf (157,902 Mcf less 122,156 Mcf),
23 must come from somewhere. In fact, this difference is

1 made up by increased withdrawals of gas from Supply's
2 storage facilities, in excess of volumes required for
3 sales service customers. This conclusion is
4 inescapable irrespective of whether the transportation
5 service customer moves gas supplies only on
6 Distribution's system or whether it moves gas supplies
7 on both Distribution's system and Supply's system.
8 Based on the foregoing, in order for Distribution's
9 rates to be fair to all customers, Distribution must
10 recover from transportation service customers costs
11 associated with use of Supply's storage facilities,
12 including costs for injection and withdrawal of gas
13 into and from storage, storage capacity costs, storage
14 deliverability costs and shrinkage.

15 In designing an appropriate form of
16 transportation rate which will include a provision for
17 recovery of costs associated with use of Supply's
18 storage and deliverability capacity to meet design
19 peak day requirements of transportation service
20 customers, realities of measurement of customer's gas
21 use and gas delivered to Distribution for customer's
22 accounts must be recognized. Presently, it is
23 impossible to determine the extent to which all

1 transportation customers individually place demands on
2 Supply's storage capacity. In order to make such
3 determination for an individual transportation service
4 customer, it would be necessary to have daily metering
5 facilities both at the premises where the customer
6 receives service from Distribution and at the point of
7 delivery of the customer's gas supplies to
8 Distribution for transportation to the customer. Only
9 by having daily data concerning amounts delivered to
10 Distribution for the customer's account and amounts
11 used by the customer could the actual shortfall, which
12 must be made up on peak day utilizing Supply's storage
13 services, be quantified.

14 Installation of such metering facilities,
15 together with communication facilities to transmit
16 daily metering information to Distribution for
17 analysis, for all transportation service customers
18 would be exceedingly expensive, since Distribution
19 presently has approximately 3,800 MMT and DMT
20 transportation service customers in Pennsylvania and
21 receives gas supplies for customers' accounts at
22 hundreds of points of delivery.

23 The total purchased gas costs associated

1 with transportation customer imbalances are provided
2 on PGC Exhibit No.24A. Tables I through V on PGC
3 Exhibit No.24A present the calculation of purchased
4 gas costs associated with transportation customer
5 imbalances. Purchased gas costs associated with
6 transportation imbalances can be segregated into two
7 general components: (1) costs associated with storage
8 requirements (Tables I through IV), and (2)
9 transportation costs associated with moving such gas
10 from storage (Table V).

11 The storage costs associated with
12 transportation customer imbalances (Tables I through
13 IV) were calculated using Supply's Enhanced Storage
14 Service ("ESS") rates. Four rate components are
15 included in Supply's ESS Rate Schedule: (1)
16 deliverability, (2) capacity, (3) injection and
17 withdrawal, and (4) shrinkage.

18 The deliverability cost component is
19 summarized in Table I of PGC Exhibit No.24A. The
20 storage deliverability requirement in Table I of
21 29,589 Mcf is equal to the MMT design peak day
22 deficiency of 27,010 Mcf calculated in PGC Exhibit No.
23 26-B, plus a local production amount of 1,932 Mcf

1 which is a balancing requirement for monthly metered
2 local production deliveries that MMNGS customers rely
3 on during a winter period, plus an amount of 647 Mcf
4 of allocated contingency capacity. Contingency
5 capacity assures reliability in the event a marketer
6 fails to deliver its required supplies, as well as to
7 protect the sales customers should there be a capacity
8 or supplier failure, or should the system experience
9 load requirements that exceed current peak day
10 projections. The total deliverability requirement is
11 29,589 Mcf (27,010 Mcf + 1,932 Mcf + 647 Mcf).

12 The design peak day deficiency requirements
13 of DMT customers are excluded from the MMT storage
14 deliverability calculation, because, in a previous
15 Distribution 1307(f) proceeding (R-953487), the
16 Commission modified the DMT service so that, during
17 critical supply situations, a DMT customer's access to
18 overdelivered gas supplies is extremely limited. In
19 effect, a DMT customer's access to peak day storage
20 deliverability is interruptible. Since such access is
21 interruptible, it is not appropriate to allocate such
22 costs to transportation customers.

23 Table II of PGC Exhibit No.24A calculates

1 the ESS capacity costs associated with total
2 overdeliveries of transportation customers. The
3 capacity charged to transportation customers is equal
4 to the average monthly balancing storage inventories
5 the 12 months ended July 2023.

6 The storage injection and withdrawal costs
7 associated with balancing transportation customers'
8 usage and deliveries are provided in Table III of PGC
9 Exhibit No.24A.

10 Supply's ESS rate is also subject to a
11 shrinkage factor of 0.92%. The cost of shrinkage for
12 storage services related to transportation customers
13 is the average storage capacity reserved for
14 transportation service multiplied by the shrinkage
15 factor times Distribution's average commodity cost of
16 purchased gas. Table IV of PGC Exhibit No.24A shows
17 the shrinkage cost calculation.

18 In addition to storage service, it is
19 necessary for such gas to be moved from storage
20 fields. In order to move gas from ESS storage,
21 Enhanced Firm Transportation ("EFT") is required also.
22 Supply's ESS service does not include the associated
23 costs of transportation service. Table V of PGC

Exhibit No.24A summarizes costs of Supply's EFT capacity which must be used by Distribution in order to move gas from storage to meet monthly metered transportation customers' design peak day deficiency requirements.

The total purchased gas costs associated with transportation customer imbalances is the sum of the costs identified on Tables I through V of PGC Exhibit No.24A.

C) MMT Rate Proposed By Distribution

The unit MMT rate resulting from the costs incurred to support transportation imbalances is \$0.5792/Mcf ($\$0.5792/\text{Mcf} = \$5,048,613$ divided by 8,716,345 Mcf). The current MMT rate is \$0.37/Mcf. The Company is proposing an increase to the rate to \$0.58/Mcf.

D) Charges for Transportation

Overdeliveries and Underdeliveries for
Daily Metered Transportation Customers

Distribution established its DMT rate schedule in the first 1307(f) proceeding affected by Order 636. Distribution implemented substantial changes to its banking/balancing services for transportation customers in that proceeding. These

1 changes were due to the fact that, following Supply's
2 restructuring proceeding under FERC Order 636,
3 Distribution in fact provided banking/balancing
4 service by use of Supply's storage facilities and
5 upstream pipeline capacity - not by changes in levels
6 of gas purchases from Supply at different times.
7 Following restructuring, Distribution scheduled
8 deliveries of gas to it and for its account into
9 storage. All differences between the volume of gas
10 scheduled by Distribution from gas producers and the
11 volume of gas delivered to Distribution's customers,
12 including transportation imbalances, other than
13 shrinkage, will cause increases or decreases in the
14 volumes of gas injected into or withdrawn from storage
15 facilities. Therefore, banking and balancing charges
16 were based on costs incurred to provide the service,
17 primarily storage-related costs and costs of upstream
18 pipeline capacity on Supply.

19 DMT service includes a 2% tolerance level
20 for imbalance charges to recognize the potential for
21 measurement errors of the DMT customer's consumption.
22 A balancing tolerance of 2% is reasonable and should
23 be achievable by most DMT customers. Therefore, so

1 long as a customer has a banked balance which does not
2 exceed 2% of the volume of gas transported by
3 Distribution to it in the billing month, there will be
4 no additional charge for banking/balancing service.

5 If, however, the customer has an
6 overdelivery imbalance in excess of 2% of the volume
7 of gas transported to the customer by Distribution
8 during the billing month, but less than 37% of the
9 volume transported, the customer will incur an
10 additional charge. The amount of the additional
11 charge is currently \$0.6351 per Mcf. Distribution is
12 not proposing to change this rate at this time.

13 A greater charge will be applied to
14 transportation service customers using Distribution's
15 banking/balancing service when volumes in storage
16 exceed 37% of the volume of gas Distribution delivered
17 to the customer during the billing month.

18 Historically, approximately thirty-seven percent of
19 sales customers' normal winter requirements are met
20 with gas from storage. The remainder of sales
21 customers' requirements are met by gas transported on
22 upstream pipelines. Therefore, to the extent that a
23 transportation customer has banked more than 37% of

1 its requirements, it is using storage to a greater
2 degree than are sales customers. The transportation
3 customer is, therefore, preventing the use of storage
4 for sales customers and requiring the use of upstream
5 capacity. It is only fair that when a transportation
6 customer meets more than 37% of its requirements
7 through storage it should contribute to recovery of
8 the costs of upstream capacity. The additional rate
9 for use of banking/balancing service in excess of 37%
10 of volumes delivered to transportation service
11 customers during a billing month is designed to
12 provide a contribution to recovery of costs of
13 upstream pipeline capacity and to provide a further
14 incentive for transportation customers and their
15 suppliers to match customer usage with deliveries. All
16 banked volumes exceeding 37% of monthly transportation
17 deliveries are currently billed at a \$0.7624 per Mcf
18 rate. Distribution is not proposing to change this
19 rate at this time.

20 It is important to recognize that
21 Distribution did not design its charges for
22 overdeliveries to be a gas storage service.
23 Distribution has designed the overdelivery rates to

1 provide an incentive to its transportation customers
2 and their marketers to match as closely as possible a
3 customer's gas usage with the customer's
4 transportation deliveries. Distribution believes its
5 overdelivery charge achieves this incentive while at
6 the same time providing a mechanism that recovers the
7 costs of overdelivery services.

8 When a DMT customer on any day uses gas
9 supplies in excess of current deliveries and prior
10 "banked" volumes, the customer is using Distribution's
11 gas supplies for which it must, under the
12 restructuring procedures pursuant to FERC Order 636,
13 contract directly with producers or other gas
14 suppliers. When a DMT service customer is truly
15 drawing upon Distribution's gas supplies, it is only
16 fair that the customer compensate Distribution, and
17 Distribution's sales customers, for use of such gas
18 supply.

19 Therefore, in its first 1307(f) proceeding
20 affected by Order 636, Distribution proposed, and the
21 Commission accepted (with the exception of a 2% daily
22 delivery tolerance for DMT underdeliveries), that
23 transportation customer's use of Distribution's gas

1 supplies be considered a sale of gas by Distribution
2 to the customer, which cannot be eliminated by
3 subsequent overdeliveries. Distribution is not
4 proposing to change this requirement for DMT customers
5 in this proceeding.

Table I

MMT Storage Deliverability Requirement (Mcf)	29,589	
Multiplied by:		
Dth Conversion Factor	<u>1.0500</u>	
Equals:		
Storage Deliverability Requirement (Dth)	31,069	
Multiplied by:		
Monthly ESS Deliverability Charge (\$ per Dth)	<u>\$ 4.2337</u>	
Equals:		
Monthly Deliverability Cost	\$ 131,536	
Multiplied by:		
Number of Months in the Year	<u>12</u>	
Equals:		
Total Annual Deliverability Costs		\$ 1,578,434

Table II

Capacity Requirement (Mcf)	130,151	
Multiplied by:		
Dth Conversion Factor	<u>1.0500</u>	
Equals:		
Capacity Requirement (Dth)	136,659	
Multiplied by:		
Monthly ESS Capacity Charge (\$ per Dth)	<u>\$ 0.0748</u>	
Equals:		
Monthly Capacity Cost	\$ 10,222	
Multiplied by:		
Number of Months in the Year	<u>12</u>	
Equals:		
Total Annual Capacity Cost		\$ 122,665

Table III

Capacity Requirement (Mcf)	130,151	
Multiplied by:		
Dth Conversion Factor	<u>1.0500</u>	
Equals:		
Capacity Requirement (Dth)	136,659	
Multiplied by:		
ESS Injection/Withdrawal Charge (\$ per Dth)	<u>\$ 0.0396</u>	
Equals:		
Total ESS Injection/Withdrawal Charge		\$ 5,412

Table IV

Capacity Requirement (Mcf)	130,151	
Multiplied by:		
Shrinkage Factor	<u>0.92%</u>	
Equals:		
Amount of Shrinkage (Mcf)	1,197	
Multiplied by:		
Average Upstream Commodity Gas Cost (\$/Mcf)	<u>\$ 3.3764</u>	
Equals:		
Shrinkage Cost		\$ 4,043

Table V

Storage Deliverability Requirement (Mcf)	29,589	
Multiplied by:		
Dth Conversion Factor	<u>1.0500</u>	
Equals:		
Storage Deliverability Requirement (Dth)	31,069	
Multiplied by:		
Monthly EFT Reservation Charge (\$ per Dth)	<u>\$ 8.9534</u>	
Equals:		
Monthly EFT Reservation Cost	\$ 278,172	
Multiplied by:		
Number of Months in the Year	<u>12</u>	
Equals:		
Total Annual EFT Reservation Costs		<u>\$ 3,338,060</u>
Total Cost		\$ 5,048,613
MMT Volumes		8,716,345
MMT Unit Costs		<u>\$ 0.5792</u>
Current MMT Rate		<u>\$0.3700</u> effective 8/1/2023
Proposed MMT Rate		<u>\$0.5800</u>

MMT Volumes - Actual TME Consumption (Mcf)

Source: PA Revenue Report - EFACT Volumes tab. Use the "DUAL" Total

Billed Revenue Month	
Dec 22	921,910
Jan 23	1,221,302
Feb	1,157,483
Mar	1,067,072
Apr	1,056,128
May	669,731
Jun	481,045
Jul	379,666
Aug	352,471
Sep	364,813
Oct	415,660
Nov 23	629,066
	8,716,345

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Statement to show Wellhead Price Projection for December 2023 through December 2025.

Page 2 of this Exhibit provides the Wellhead Price Projection for December 2023 through December 2025.

As shown on pages 3-5, the following sources were used to calculate the Wellhead Projection Price:

1. EIA Short Term Energy Outlook for Henry Hub Spot Natural Gas Price – Page 3
 - Most recent published data for Natural Gas Variable NGHHUUS
2. NYMEX Settle and Calculated Average of Trading Days for Prompt Month – Page 4
 - November 2023 Close @ October 27, 2023
3. PIRA Price Projections at Henry Hub (PIRA is formerly known as BENTEK Energy, LLC) – Page 5
 - Most recent forecast data from S&P Global Platts PIRA North American Gas

An arithmetic average was determined from these three sources to calculate the Projected Wellhead Price.

National Fuel Gas Distribution Corporation
2024 1307(f) Filing
Wellhead Price Projection

		Note 1	Note 2	Note 3	Projected NFG Receipt Price
		EIA Henry Hub Spot Natural Gas Price (\$/Dth)	NYMEX Settle/Average (\$/Dth)	PIRA Henry Hub (\$/Dth)	Price (\$/Dth)
Projected Month		(A)	(B)	(C)	(D)
November	2023	\$3.190	\$3.164	\$2.800	\$3.051
December	2023	\$3.600	\$3.483	\$3.337	\$3.473
January	2024	\$3.650	\$3.718	\$3.548	\$3.639
February	2024	\$3.410	\$3.648	\$3.439	\$3.499
March	2024	\$3.220	\$3.351	\$3.115	\$3.229
April	2024	\$2.940	\$3.130	\$2.858	\$2.976
May	2024	\$2.890	\$3.148	\$2.826	\$2.955
June	2024	\$2.980	\$3.255	\$2.735	\$2.990
July	2024	\$3.190	\$3.368	\$2.865	\$3.141
August	2024	\$3.260	\$3.398	\$3.175	\$3.278
September	2024	\$3.260	\$3.377	\$2.986	\$3.208
October	2024	\$3.280	\$3.452	\$3.005	\$3.246
November	2024	\$3.390	\$3.808	\$3.767	\$3.655
December	2024	\$3.600	\$4.251	\$4.345	\$4.065
January	2025		\$4.519	\$4.519	\$4.519
February	2025		\$4.415	\$4.447	\$4.431
March	2025		\$4.043	\$4.148	\$4.095
April	2025		\$3.644	\$3.818	\$3.731
May	2025		\$3.630	\$3.845	\$3.738
June	2025		\$3.750	\$4.113	\$3.932
July	2025		\$3.875	\$4.420	\$4.147
August	2025		\$3.911	\$4.488	\$4.199
September	2025		\$3.881	\$4.670	\$4.276
October	2025		\$3.949	\$4.631	\$4.290
November	2025		\$4.270	\$4.850	\$4.560
December	2025		\$4.652	\$5.273	\$4.962
Average		<u>\$3.280</u>	<u>\$3.757</u>	<u>\$3.810</u>	<u>\$3.769</u>
August 2023-July 2024		<u>\$3.360</u>	<u>\$3.847</u>	<u>\$3.880</u>	<u>\$3.837</u>

Footnote:

1. EIA Short-Term Energy Outlook for Henry Hub Spot Natural Gas Price as of November 7, 2023
2. NYMEX Settle as of October 27, 2023
3. US Gas Short-Term Forecast projection at Henry Hub from S&P Global Platts/PIRA North American Gas (formerly known as BENTEK Energy, LLC) as of November 17, 2023

National Fuel Gas Distribution Corporation
2024 1307(f) Filing



U.S. Energy Information
Administration

SHORT-TERM ENERGY OUTLOOK

Variable	Description	Units	Data History	Data Forecast
NGHHUUS	Henry Hub Spot natural gas price	\$/MMBTU	---	EIA's Short-Term Integrated Forecasting System

Note: Data history sources refers to database supporting publication noted.
All forecasts are from the November 7, 2023 Short-Term Energy Outlook.

Date	NGHHUUS
Nov-23	3.19
Dec-23	3.60
Jan-24	3.65
Feb-24	3.41
Mar-24	3.22
Apr-24	2.94
May-24	2.89
Jun-24	2.98
Jul-24	3.19
Aug-24	3.26
Sep-24	3.26
Oct-24	3.28
Nov-24	3.39

National Fuel Gas Distribution Corporation
2024 1307(f) Filing

New York Mercantile Exchange (NYMEX)
Prompt Month = November 2023 Close @ October 27, 2023

		(\$/Dth)	
November	2023	\$3.164	Settle
December	2023	\$3.483	
January	2024	\$3.718	
February	2024	\$3.648	
March	2024	\$3.351	
April	2024	\$3.130	
May	2024	\$3.148	
June	2024	\$3.255	
July	2024	\$3.368	
August	2024	\$3.398	
September	2024	\$3.377	
October	2024	\$3.452	
November	2024	\$3.808	
December	2024	\$4.251	
January	2025	\$4.519	
February	2025	\$4.415	
March	2025	\$4.043	
April	2025	\$3.644	
May	2025	\$3.630	
June	2025	\$3.750	
July	2025	\$3.875	
August	2025	\$3.911	
September	2025	\$3.881	
October	2025	\$3.949	
November	2025	\$4.270	
December	2025	\$4.652	

National Fuel Gas Distribution Corporation
2024 1307(f) Filing

S&P Global

Platts

PIRA North American Gas

Date: 10/24/2023

**Henry Hub
(\$/MMBtu)**

Nov-23	\$2.80
Dec-23	\$3.34
Jan-24	\$3.55
Feb-24	\$3.44
Mar-24	\$3.11
Apr-24	\$2.86
May-24	\$2.83
Jun-24	\$2.73
Jul-24	\$2.86
Aug-24	\$3.18
Sep-24	\$2.99
Oct-24	\$3.00
Nov-24	\$3.77
Dec-24	\$4.34
Jan-25	\$4.52
Feb-25	\$4.45
Mar-25	\$4.15
Apr-25	\$3.82
May-25	\$3.85
Jun-25	\$4.11
Jul-25	\$4.42
Aug-25	\$4.49
Sep-25	\$4.67
Oct-25	\$4.63
Nov-25	\$4.85
Dec-25	\$5.27

National Fuel Gas Distribution Corporation
Pennsylvania Division

Extreme Peak Day

National Fuel Gas Distribution Corporation (“Distribution” or the “Company”) identifies peak day requirements for capacity planning purposes on pages 2 and 3 of this Exhibit.

With respect to page 2, Column A contains total requirements on a throughput basis in Mcf. Columns B and C contain the Monthly Metered Transportation (“MMT”) imbalance requirement in Mcf, at 52 and 22 degree days respectively. It should be noted that the MMT imbalance requirement at 22 degree days is the difference between 74 degree days and 52 degree days. Column D contains the Daily Metered Transportation (“DMT”) imbalance requirement in Mcf, which is calculated as 2% of DMT requirements.

Page 3 provides a calculation of the MMT requirements in Mcf, at 52 degree days. For heat sensitive customer classes (residential, commercial and public authority), Distribution utilizes a method of extracting a base load volume and computing a daily heating volume for 52 degree days. The daily base load volume is added to the daily heating volume to determine the base case peak day requirements at 52 degree days. Gas usage of customers in the industrial classes (i.e., Small Volume Industrial Service, Intermediate Volume Industrial Service, Large Volume Industrial Service, and Large Industrial Service) represents an average day.

National Fuel Gas Distribution Corporation
Pennsylvania Division
2025 Extreme Peak Day for Capacity Allocation
Volumes in Mcf

	(A)	(B)	(C)	(D)
	74 Degree Days	52 Degree Days	22 Degree Days	Daily Metered Transportation (DMT) Imbalance
Retail Sales				
Residential	220,297			
Commercial	39,720			
Industrial - SVIS and IVIS ⁽¹⁾	2,644			
Public Authority	3,335			
Company Use	74			
Total Retail Sales	266,070			
Retail Shrinkage (0.15%)	400			
Total Retail Sales Requirements	266,470			
Transportation Service				
Small Aggregation Transportation (SATC)				
Residential	21,237			
Commercial	2,875			
Industrial - SVIS and IVIS ⁽¹⁾	294			
Public Authority	196			
Small Aggregation Transportation (SATC) Service	24,602			
Small Aggregation Transportation (SATC) Shrinkage (0.15%)	37			
Small Aggregation Transportation (SATC) Requirements	24,639			
Monthly Metered Transportation (MMT)				
Residential	1,554	1,115	439	
Commercial	43,984	31,530	12,454	
Industrial - SVIS and IVIS ⁽¹⁾	21,555	14,602	6,953	
Industrial - LVIS ⁽²⁾	2,613	2,047	566	
Industrial - LIS ⁽³⁾	1,002	1,038	-36	
Public Authority	23,292	16,697	6,595	
Monthly Metered Transportation (MMT) Service	94,000	67,029	26,971	
Monthly Metered Transportation (MMT) Shrinkage (0.15%)	141	101	40	
Monthly Metered Transportation (MMT) Requirements	94,141	67,130	27,011	
Daily Metered Transportation (DMT)				
Commercial	4,216			
Industrial - IVIS ⁽⁴⁾	7,449			
Industrial - LVIS ⁽²⁾	7,112			
Industrial - LIS ⁽³⁾	37,376			
Industrial - DMLMTS ⁽⁵⁾	6,018			
Public Authority	1,494			
Daily Metered Transportation (DMT) Service	63,665			
Daily Metered Transportation (DMT) Shrinkage (0.15%)	96			
Daily Metered Transportation (DMT) Requirements	63,761			
Daily Metered Transportation (DMT) Imbalance (2% of DMT Requirements)				1,275
Total Transportation Service	182,266			
Total Transportation Service Shrinkage (0.15%)	274			
Total Transportation Service Requirements	182,540			
Total Throughput	448,336			
Total Throughput Shrinkage (0.15%)	674			
Total Requirements	449,010			

Footnotes:

- (1) SVIS is Small Volume Industrial Service and IVIS is Intermediate Volume Industrial Service.
- (2) LVIS is Large Volume Industrial Service.
- (3) LIS is Large Industrial Service.
- (4) IVIS is Intermediate Volume Industrial Service.
- (5) DMLMTS is Daily Metered Large Manufacturing Transportation Service.

National Fuel Gas Distribution Corporation
Pennsylvania Division
2025 Extreme Peak Day for Capacity Allocation
Volumes in Mcf
Shrinkage 0.15%

BASE CASE

JANUARY NORMAL DEGREE DAYS =	1,116						2025
	Jan-25	Monthly Base Load	Monthly Heat Load	Heat Load/ Normal DD	Daily Heat Load @ 52 DD	Daily Base Load @ Normal DD	52 DEG DAYS
Transportation Service							
Monthly Metered Transportation (MMT)							
Residential	24,623	2,289	22,334	20	1,041	74	1,114
Commercial	696,581	64,755	631,827	566	29,440	2,089	31,529
Industrial - SVIS and IVIS ⁽¹⁾	452,669						14,602
Industrial - LVIS ⁽²⁾	63,460						2,047
Industrial - LIS ⁽³⁾	32,185						1,038
Public Authority	368,881	34,292	334,590	300	15,590	1,106	16,696
MMT Transportation Service	1,638,398						67,026
MMT Transportation Shrinkage	2,461						101
MMT Transportation Requirements	1,640,859						67,127

Footnotes:

- (1) SVIS is Small Volume Industrial Service and IVIS is Intermediate Volume Industrial Service.
(2) LVIS is Large Volume Industrial Service.
(3) LIS is Large Industrial Service.

National Fuel Gas Distribution Corporation
Pennsylvania Division

Capacity Allocation

2025 Design Peak Day (74 DD) Citygate Requirements
BTU factor: 1.05

Capacity:	Capacity Requirements (Mcf)	Capacity Requirements (Dth)
Distribution's Capacity Requirement		
- Retail	266,470	279,794
- Small Aggregation Transportation Customers (SATC)	24,639	25,871
- Monthly Metered Transportation (MMT) Imbalance	27,010	28,361
- Daily Metered Transportation (DMT) Imbalance (2% of DMT)	1,275	1,339
- Priority Standby Requirement	5,529	5,805
- Local Production Balancing	1,932	2,029
Total	326,855	343,199
Non-SATC Transportation Capacity Requirement		
- MMT Customers	94,141	98,848
- DMT Customers	63,761	66,949
Sub-Total	157,902	165,797
- Less Priority Standby Requirement from Distribution	(5,529)	(5,805)
- Less MMT Balancing from Distribution	(27,010)	(28,361)
- Less DMT Balancing from Distribution	(1,275)	(1,339)
- Less Local Production Balancing from Distribution	(1,932)	(2,029)
Total Non-SATC Transportation Capacity Requirement	122,156	128,263
Sub-Total Capacity Requirement	449,011	471,462
Plus:		
Contingency Capacity Requirement	7,311	7,677
Total Capacity Requirement	456,322	479,139

**NATIONAL FUEL GAS DISTRIBUTION CORPORATION
BUFFALO, NEW YORK
RATES, RULES AND REGULATIONS
GOVERNING THE FURNISHING
OF
NATURAL GAS SERVICE
IN
TERRITORY DESCRIBED HEREIN**

Issued: January 31, 2024

Effective: August 1, 2024

D. L. DeCAROLIS, PRESIDENT
BUFFALO, NEW YORK

This Supplement includes increases and decreases to existing rates.
See page 2.

NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9
Two-Hundred-Thirty-Sixth Revised Page No. 2
Canceling Two-Hundred-Thirty-Fifth Revised Page No. 2

LIST OF CHANGES MADE BY THIS TARIFF

INCREASE:

1. Distribution Charge for Residential, Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial Service Classes increase.
Pages 36, 36A, 41, 41A, 42, 53, 55, 65, 66, 76
2. Gas Adjustment Charges increase for Residential, Commercial and Public Authority, Small Volumes Industrial, Intermediate Volume Industrial, and Large Industrial Service
Pages 36, 41, 41A, 42, 53, 55, 65, 76
3. The Natural Gas Supply Charge for Residential, Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial Service Classes increase.
Pages 36A, 41, 41A, 42, 53, 55, 66 and 76A.
4. Demand Charges for Load Balancing Service increase.
Pages 48, 61, 72, 79, 82
5. Commodity Charges for Sales Services increase.
Pages 50, 62, 73, 80
6. Commodity Charges for Transportation Service increase.
Page 50, 63, 74, 81
7. Components of Natural Gas Vehicle rates increase.
Pages 83 and 84.
8. Priority Standby Service monthly rate increase.
Pages 93, 95
9. The price for purchase of gas by Distribution from a transportation service customer in the event of a curtailment or interruption will increase.
Pages 106, 117 and 146G.
10. Purchased gas costs in Rider A increase.
Page 147
11. The Price to Compare shown in Rider H increases.
Page 169.
12. MMT Service Rates increased for Residential, "Small" Commercial/ Public Authority >25,000, "Large" Commercial/ Public Authority, Intermediate Volume Industrial, Large Volume Industrial, and Large Industrial Service Classes.
Pages 100 and 101

LIST OF CHANGES MADE BY THIS TARIFF

INCREASE:

13. SATC Transportation Service rates increase for Residential and Small Volume Industrial.
Page 119A, 120, 121
14. Certain Demand Transfer Recovery Rates ("DTR") increase.
Page 127.
15. SATC Alternative Capacity Release Rate increase.
Page 131.
16. The Merchant Function Charge in Rider G increase.
Page 168.

DECREASE:

17. Weighted average demand cost of upstream capacity increases.
Page 131.

NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

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Gas - Pa. P.U.C. No. 9

Two-Hundred-Thirty-Sixth Revised Page No. 4

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One-Hundred-Thirtieth Revised Page No. 5
Canceling One-Hundred-Twenty-Ninth Revised Page No. 5

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DISTRIBUTION CORPORATION

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RESIDENTIAL SERVICE RATE SCHEDULE

RESIDENTIAL CLASSIFICATION

This classification shall include gas supplied for residential purposes such as a private dwelling, apartment house with a single meter supplying four or less dwelling units, separately metered apartments of a multiple dwelling, accessory buildings to dwellings or apartment houses such as garages, except at residences receiving service under Rate Schedule LIRAS for Low Income Residential Assistance Service and other places of residence where gas is used for residential purposes.

Churches and missions (places of worship) shall be entitled to Service under the Residential service rate schedule.

AVAILABILITY OF SERVICE

Gas Service shall be available at one location, except as otherwise provided, for residential customers.

APPLICABILITY

Applicable in all areas served under this tariff.

MONTHLY RATE

Basic Service Charge		
\$14.00	per Month	
Distribution Charges		
34.036¢	per 100 cubic feet	(I)
Gas Adjustment Charge		
(0.479)¢	per 100 cubic feet	Purchased Gas Cost Component (I)
		(Rider A)
<u>(0.009)¢</u>	per 100 cubic feet	Merchant Function Charge (I)
		(Rider G)
(0.488)¢	Per 100 cubic feet	Total Gas Adjustment Charge (I)

(D) Indicates Decrease

(I) Indicates Increase

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RESIDENTIAL SERVICE RATE SCHEDULE (cont.)

Natural Gas Supply Charge			
55.335¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.998¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
<u>1.149¢</u>	per 100 cubic feet	Gas Procurement Charge (Rider H)	
57.482¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 1.8032% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223. The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge. Residential rate classes shall be subject to Rider F - LIRA Discount Charge as set forth in this tariff.

RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9
One-Hundred-Seventeenth Revised Page No. 41
Canceling One-Hundred-Sixteenth Revised Page No.41

COMMERCIAL AND PUBLIC AUTHORITY SERVICE RATE SCHEDULE (cont.)

APPLICABILITY

Applicable in all areas served under this tariff.

MONTHLY RATE

For "Small" Commercial/Public Authority Customers using not more than 250,000 cubic feet per year:

Basic Service Charge		
\$27.00	per Month	
Distribution Charges		
27.419¢	per 100 cubic feet	(I)
Gas Adjustment Charge		
(0.479)¢	per 100 cubic feet	Purchased Gas Cost Component (I)
		(Rider A)
<u>(0.002)¢</u>	per 100 cubic feet	Merchant Function Charge (I)
		(Rider G)
(0.481)¢	per 100 cubic feet	Total Gas Adjustment Charge (I)
Natural Gas Supply Charge		
55.335¢	per 100 cubic feet	Purchased Gas Cost Component (I)
		(Rider A)
0.188¢	per 100 cubic feet	Merchant Function Charge (I)
		(Rider G)
<u>1.149¢</u>	per 100 cubic feet	Gas Procurement Charge (Rider H)
56.672¢	per 100 cubic feet	Total Natural Gas Supply Charge (I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non=purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

Seventy-First Revised Page No. 41A
Canceling Seventieth Revised Page No. 41A

COMMERCIAL AND PUBLIC AUTHORITY SERVICE RATE SCHEDULE (Cont'd)

For "Small" Commercial/Public Authority Customers using greater than 250,000 cubic feet but not more than 1,000,000 cubic feet per year:

Basic Service Charge			
\$37.00	per Month		
Distribution Charges			
24.980¢	per 100 cubic feet		(I)
Gas Adjustment Charge			
(0.479)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
<u>(0.002)¢</u>	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(0.481)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)
Natural Gas Supply Charge			
55.335¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.188¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
<u>1.149¢</u>	per 100 cubic feet	Gas Procurement Charge (Rider H)	
56.672¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

One-Hundred-Seventeenth Revised Page No. 42
Canceling One-Hundred-Sixteenth Revised Page No. 42

Commercial and Public Authority Service Rate Schedule (Cont'd)

For "Large" Commercial/Public Authority Customers:

Basic Service Charge			
\$151.00	per Month		
Distribution Charges			
21.047¢	per 100 cubic feet		(I)
Gas Adjustment Charge			
(0.479)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
<u>(0.002)¢</u>	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(0.481)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)
Natural Gas Supply Charge			
55.335¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.188¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
<u>1.149¢</u>	per 100 cubic feet	Gas Procurement Charge (Rider H)	
56.672¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

APPLICATION PERIOD

The Application Period shall be the twelve months beginning March 1 of each year.

RULES AND REGULATIONS

The Rules and Regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

One-Hundred-Second Revised Page No. 48
Canceling One-Hundred-First Revised Page No. 48

1. The purchased gas demand costs applicable to the Residential, Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial classes, the "DC", shall be obtained from Rider "A" - Section 1307(f) Purchased Gas Costs.
2. The number 12 shall be multiplied by the sum of (a) the volume of gas (expressed in Mcf) purchased from the Company by all Residential, Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial customers, during the Company peak Sales Month and (b) the volume of service (expressed in Mcf) to all customers under the "Monthly Volume" provisions of Rate Schedule SB, during the Company Peak Sales Month.
 - (a) "Company Peak Sales Month" is defined as the calendar month within which the Company experienced the System-Wide Peak Sales Day, such month being December, January or February preceding the Section 1307(f) Application Period for which the determination of the rate per Gas BDU is being made.
 - (b) "System-Wide Peak Sales Day" is defined as the day of maximum gas purchased by the Company, including all volumes of gas purchased from the Company throughout its entire system in the states of Pennsylvania and New York.
3. The amount determined in Item 1 above shall be divided by the amount determined in Item 2 above to determine the amount included in the rate for recovery of purchased gas costs.
4. The rate per Gas BDU shall be the amount for purchased gas demand costs (Item 3).

The current rate per Gas BDU is as follows:

Purchased Gas Demand Cost	\$1.2315/BDU	(I)

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made, under Items 1, 2 and 3, above, of the component to be included in the rate for purchased gas demand costs and the rate per Gas BDU shall be changed accordingly.

(D) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9
One-Hundred-Ninth Revised Page No. 50
Canceling One-Hundred-Eighth Revised Page No. 50

B. COMMODITY CHARGES FOR SALES AND FOR TRANSPORTATION SERVICE

1. Commodity Charge for Sales Service

The monthly Commodity Charge for Sales Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas sold to the Customer by the Company during the applicable billing cycle.

The rate per Mcf shall be determined as follows and shall be \$3.8678 (I)
per Mcf, subject to revision as provided below:

The current components of the rate are as follows:

Purchased Gas Commodity		
Costs, set forth in Rider "A"	\$3.3112/Mcf	(I)
Non Gas Costs	\$0.5566/Mcf	

a. Determination of Rate per Mcf

The rate per Mcf shall be the sum of:

1. The net amount per Mcf for recovery of the commodity component of purchased gas costs and for recovery or refund of "E" factor amounts, the "PGCC", as determined in Rider "A" - Section 1307(f) Purchased Gas Costs of this tariff; plus
2. The amount of \$0.5566 per Mcf for recovery of non-gas costs.

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made of the commodity component of purchased gas costs (Item 1, above) and the rate per Mcf shall be changed accordingly. The component included in the rate for recovery of non-gas costs shall remain constant until changed in accordance with a procedure, other than a proceeding pursuant to Section 1307(f) of the Public Utility Code, 66 Pa.C.S. Section 1307(f).

2. Commodity Charge for Transportation Service

The monthly Commodity Charge for Transportation Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas transported by the Company to the Customer's load balancing facilities.

The rate per Mcf for transportation of gas under this rate schedule (I)
shall be \$1.1366 per Mcf, which includes \$0.5566 for recovery of non-gas costs
and \$0.5800 for recovery of purchased gas.

(I)

(D) Indicates Decrease

(I) Indicates Increase

NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9
One-Hundred-Fourteenth Revised Page No. 53
Canceling One-Hundred-Thirteenth Revised Page No. 53

SVIS
Small Volume Industrial Service Rate Schedule (Cont'd)

MONTHLY RATE

Basic Service Charge			
\$82.00	per Month		
Distribution Charges			
25.147¢	per 100 cubic feet		(I)
Gas Adjustment Charge			
(0.479)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
<u>(0.002)¢</u>	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(0.481)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)
Natural Gas Supply Charge			
55.335¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.188¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
<u>1.149¢</u>	per 100 cubic feet	Gas Procurement Charge (Rider H)	
56.672¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge.

APPLICATION PERIOD

The Application Period shall be the twelve months beginning March 1 of each year.

RULES AND REGULATIONS

The Rules and Regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

One-Hundred-Fourteenth Revised Page No. 55

Canceling One-Hundred-Thirteenth Revised Page No. 55

IVIS

INTERMEDIATE VOLUME INDUSTRIAL SERVICE RATE SCHEDULE (Cont'd)
MONTHLY RATE

Basic Service Charge			
\$252.00	per Month		
Distribution Charges			
17.772¢	per 100 cubic feet		(I)
Gas Adjustment Charge			
(0.479)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
<u>(0.002)¢</u>	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(0.481)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)
Natural Gas Supply Charge			
55.335¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.188¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
<u>1.149¢</u>	per 100 cubic feet	Gas Procurement Charge (Rider H)	
56.672¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

APPLICATION PERIOD

The Application Period shall be the twelve months beginning March 1 of each year.

RULES AND REGULATIONS

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

One-Hundred-Second Revised Page No. 61
Canceling One-Hundred-First Revised Page No. 61

Industrial and Large Industrial customers, during the Company peak Sales Month defined in Rate Schedule CPA-LBS and (b) the volumes of service (expressed in Mcf) to all customers under the "Monthly Volume" provisions of Rate Schedule SB, during the Company Peak Sales Month defined in Rate Schedule CPA-LBS.

3. The amount determined in Item 1 above shall be divided by the amount determined in Item 2 above to determine the amount included in the rate for recovery of purchased gas costs.
4. The rate per Gas BDU shall be the amount for purchased gas demand costs (Item 3).

The current rate per Gas BDU is as follows:

Purchased Gas Demand Cost	\$1.2315/BDU	(I)

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made, under Items 1, 2 and 3, above, of the component to be included in the rate for purchased gas demand costs and the rate per Gas BDU shall be changed accordingly.

b. Determination of Customer's Gas BDUs

The Customer's Gas BDUs shall be determined as follows: The actual volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Gas BDUs applicable to Customer shall be zero (0).

(D) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

One-Hundred-Fifth Revised Page No. 62

Canceling One-Hundred-Fourth Revised Page No. 62

2. Margin Demand Charge

a. The rate per Margin BDU shall be \$.5122 per Margin BDU.

b. Determination of Customer's Margin BDUs

The Customer's Margin BDUs shall be determined as follows: The actual deliveries of gas to the Customer by Company, including not only volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities but also volumes of Customer-owned gas transported to the Customer's load balancing facilities through the Company's facilities, during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Margin BDUs applicable to Customer shall be zero (0).

B. COMMODITY CHARGES FOR SALES AND FOR TRANSPORTATION SERVICE

1. Commodity Charge for Sales Service

The monthly Commodity Charge for Sales Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas sold to the Customer by the Company during the applicable billing cycle.

The rate per Mcf shall be determined as follows and shall be \$3.6920 per Mcf, subject to revision as provided below: (I)

The current components of the rate are as follows:

Purchased Gas Commodity		
Costs, set forth in Rider "A"	\$3.3112/Mcf	(I)
Non Gas Costs	\$0.3808/Mcf	

a. Determination of Rate per Mcf

The rate per Mcf shall be the sum of:

1. The net amount per Mcf for recovery of the commodity component of purchased gas costs and for recovery or refund of "E" factor amounts, the "PGCC", as determined in Rider "A" - Section 1307(f) Purchased Gas Costs of this tariff; plus

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9
Forty-Third Revised Page No. 63
Canceling Forty-Second Revised Page No. 63

2. The amount of \$0.3808 per Mcf for recovery of non-gas costs.

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made of the commodity component of purchased gas costs (Item 1, above) and the rate per Mcf shall be changed accordingly. The component included in the rate for recovery of non-gas costs shall remain constant until changed in accordance with a procedure, other than a proceeding pursuant to Section 1307(f) of the Public Utility Code, 66 Pa.C.S. Section 1307(f).

2. Commodity Charge for Transportation Service

The monthly Commodity Charge for Transportation Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas transported by the Company to the Customer's load balancing facilities.

The rate per Mcf for transportation of gas under this rate schedule shall be \$0.9608 per Mcf, which includes \$0.3808 for recovery of non-gas costs and \$0.5800 for recovery of purchased gas. (I)

V. SURCHARGE

The non-purchased gas cost Demand Charges and the non-purchased gas cost Commodity Charge for Sales Service and the non-purchased gas cost Commodity Charge for Transportation Service shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge.

VI. AMOUNTS TO BE INCLUDED IN OVER/UNDERCOLLECTION OF GAS COSTS

Purchased gas cost revenues billed under this rate schedule shall be included as revenues for recovery of gas costs for purposes of computing Factor "E" of Company's 1307(f) rate in accordance with procedures set forth in Rider "A" - Section 1307(f) Purchased Gas Costs.

VII. SPECIAL PROVISIONS

Monthly metered Special Provisions A through J contained in the Company's Rate Schedule for Transportation Service shall apply to transportation service under this rate schedule.

VIII. RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

One-Hundred-Fourteenth Revised Page No. 65
Canceling One-Hundred-Thirteenth Revised Page No. 65

LVIS

Large Volume Industrial Service (Cont'd)

- C. An Industrial Customer, for which the Company estimates that the total volumes of gas purchased from the Company or transported by the Company during the next succeeding twelve months will be not less than 50,000 Mcf, if the Industrial Customer has used total volumes of gas in at least one billing month of not less than 4,167 Mcf, even if the Customer disagrees with the Company's estimate.
- D. An Industrial Customer for which the Company estimates that total volumes of gas to be used by the customer during the next succeeding twelve months will not be less than 50,000 Mcf of gas per year whether the gas is purchased by the Industrial Customer from the Company, delivered by the Company to the Industrial Customer, or obtained by the customer from another source.

An Industrial Customer that meets the above criteria under this rate schedule at the beginning of an Application Period is required to continue to be subject to this rate schedule during all months of such Application Period. An Industrial Customer that meets the above criteria under this rate schedule during an Application Period is required to continue to be subject to this rate schedule during all or remaining months of such Application Period.

MONTHLY RATE

Basic Service Charge			
\$1,023.00	per Month		
Distribution Charges			
14.668¢	per 100 cubic feet		(I)
Gas Adjustment Charge			
(0.479)¢	per 100 cubic feet	Purchased Gas Cost Component	(I)
		(Rider A)	
<u>(0.002)¢</u>	per 100 cubic feet	Merchant Function Charge	(I)
		(Rider G)	
(0.481)¢	Per 100 cubic feet	Total Gas Adjustment Charge	(I)

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9
Sixty-Eighth Revised Page No. 66
Canceling Sixty-Seventh Revised Page No. 66

LVIS
Large Volume Industrial Service (Cont'd)

Natural Gas Supply Charge				
55.335¢	per 100 cubic feet	Purchased Gas Cost Component	(I)	
		(Rider A)		
0.188¢	per 100 cubic feet	Merchant Function Charge	(I)	
		(Rider G)		
<u>1.149¢</u>	per 100 cubic feet	Gas Procurement		
		Charge (Rider H)		
56.672¢	per 100 cubic feet	Total Natural Gas Supply	(I)	
	Charge			

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge.

RULES AND REGULATIONS

The Rules and Regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

APPLICABLE PERIOD

The Application Period shall be the twelve months beginning March 1 of each year.

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

One-Hundred-Second Revised Page No.72
Canceling One-Hundred-First Revised Page No.72

Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial customers, during the Company Peak Sales Month defined in Rate Schedule CPA-LBS and (b) the volume of service (expressed in Mcf) to all customers under the "Monthly Volume" provisions of Rate Schedule SB, during the Company Peak Sales Month defined in Rate Schedule CPA-LBS.

3. The amount determined in Item 1 above shall be divided by the amount determined in Item 2 above to determine the amount included in the rate for recovery of purchased gas costs.
4. The rate per Gas BDU shall be the amount for purchased gas demand costs (Item 3).

The current rate per Gas BDU is as follows:

Purchased Gas Demand Cost	\$1.2315/BDU	(I)

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made, under Items 1, 2 and 3, above, of the component to be included in the rate for purchased gas demand costs and the rate per Gas BDU shall be changed accordingly.

b. Determination of Customer's Gas BDUs

The Customer's Gas BDUs shall be determined as follows: The actual volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered qualifying load balancing facilities during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered qualifying load balancing facilities that ended during on of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Gas BDUs applicable to Customer shall be zero (0).

(D) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

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2. Margin Demand Charge

a. The rate per Margin BDU shall be \$.3182 per Margin BDU.

b. Determination of Customer's Margin BDUs

The Customer's Margin BDUs shall be determined as follows: The actual deliveries of gas to the Customer by Company, including not only volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities but also volumes of Customer-owned gas transported to the Customer's load balancing facilities through the Company's facilities, during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Margin BDUs applicable to Customer shall be zero (0).

B. COMMODITY CHARGES FOR SALES AND FOR TRANSPORTATION SERVICE

1. Commodity Charge for Sales Service

The monthly Commodity Charge for Sales Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas sold to the Customer by the Company during the applicable billing cycle.

The rate per Mcf shall be determined as follows and shall be \$3.5585 per Mcf, subject to revision as provided below: (I)

The current components of the rate are as follows:

Purchased Gas Commodity		
Costs, set forth in Rider "A"	\$3.3112/Mcf	(I)
Non Gas Costs	\$0.2473/Mcf	

a. Determination of Rate per Mcf

The rate per Mcf shall be the sum of:

1. The net amount per Mcf for recovery of the commodity component of purchased gas costs and for recovery or refund of "E" factor amounts, the "PGCC", as determined in Rider "A" - Section 1307(f) Purchased Gas Costs of this tariff; plus

D) Indicates Decrease

(I) Indicates Increase

NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9
Forty-Third Revised Page No. 74
Canceling Forty-Second Revised Page No.74

2. The amount of \$0.2473 per Mcf for recovery of non-gas costs.

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made of the commodity component of purchased gas costs (Item 1, above) and the rate per Mcf shall be changed accordingly. The component included in the rate for recovery of non-gas costs shall remain constant until changed in accordance with a procedure, other than a proceeding pursuant to Section 1307(f) of the Public Utility Code, 66 Pa.C.S. Section 1307(f).

2. Commodity Charge for Transportation Service

The monthly Commodity Charge for Transportation Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas transported by the Company to the Customer's load balancing facilities.

The rate per Mcf for transportation of gas under this rate schedule shall be \$0.8273 per Mcf, which includes \$0.2473 for recovery of non-gas costs and \$0.5800 for recovery of purchased gas. (I)

V. SURCHARGE

The non-purchased gas cost Demand Charges and the non-purchased gas cost Commodity Charge for Sales Service and the non-purchased gas cost Commodity Charge for Transportation Service shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

VI. AMOUNTS TO BE INCLUDED IN OVER/UNDERCOLLECTION OF GAS COSTS

Purchased gas cost revenues billed under this rate schedule shall be included as revenues for recovery of gas costs for purposes of computing Factor "E" of Company's 1307(f) rate in accordance with procedures set forth in Rider "A" - Section 1307(f) Purchased Gas Costs.

VII. SPECIAL PROVISIONS

Monthly metered Special Provisions A through J contained in the Company's Rate Schedule for Transportation Service shall apply to transportation service under this rate schedule.

VIII. RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9
One-Hundred-Eleventh Revised Page No. 76
Canceling One-Hundred-Twelfth Revised Page No. 76

LIS

Large Industrial Service (Cont'd)

- C. An Industrial Customer, for which the Company estimates that the total volumes of gas purchased from the Company or transported by the Company during the next succeeding twelve months will be not less than 200,000 Mcf, if the Industrial Customer has used total volumes of gas in at least one billing month of not less than 17,000 Mcf, even if the Customer disagrees with the Company's estimate.

An Industrial Customer that meets the above criteria under this rate schedule at the beginning of an Application Period is required to continue to be subject to this rate schedule during all months of such Application Period. An Industrial Customer that meets the above criteria under this rate schedule during an Application Period is required to continue to be subject to this rate schedule during all or remaining months of such Application Period.

MONTHLY RATE

Basic Service Charge			
\$1,165.00 per Month			
Distribution Charges			
10.418¢ per 100 cubic feet			(I)
Gas Adjustment Charge			
(0.479)¢ per 100 cubic feet	Purchased Gas Cost Component		(I)
	(Rider A)		
(0.002)¢ per 100 cubic feet	Merchant Function Charge		(I)
	(Rider G)		
(0.481)¢ per 100 cubic feet	Total Gas Adjustment Charge		(I)

(D) Indicates Decrease

(I) Indicates Increase

NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

Fifty-Third Revised Page No. 76A

Canceling Fifty-Second Revised Page No. 76A

LIS

Large Industrial Service (Cont'd)

Natural Gas Supply Charge			
55.335¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.188¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
<u>1.149¢</u>	per 100 cubic feet	Gas Procurement Charge (Rider H)	
56.672¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge.

GAS SHORTAGE CURTAILMENT

Service under this schedule to an LIS Industrial Customer is subject to curtailment and excess consumption penalty as set forth in Rule 26 of this tariff.

RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

Effective: August 1, 2024

LBS and (b) volume of service (expressed in Mcf) to all customers under the "Monthly Volume" provisions of Rate Schedule SB, during the Company Peak Sales Month defined in Rate Schedule CPA-LBS.

3. The amount determined in Item 1 above shall be divided by the amount determined in Item 2 above to determine the amount included in the rate for recovery of purchased gas costs.
4. The rate per Gas BDU shall be the amount for purchased gas demand costs (Item 3).

The current rate per Gas BDU is as follows:

Purchased Gas Demand Cost	\$1.2315/BDU	(I)

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made, under Items 1, 2 and 3, above, of the component to be included in the rate for purchased gas demand costs and the rate per Gas BDU shall be changed accordingly.

b. Determination of Customer's Gas BDUs

The Customer's Gas BDUs shall be determined as follows: The actual volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Gas BDUs applicable to Customer shall be zero (0).

(D) Indicates Decrease

(I) Indicates Increase

NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

One-Hundred-Fifth Revised Page No. 80
Canceling One-Hundred-Fourth Revised Page No. 80

2. Margin Demand Charge

a. The rate per Margin BDU shall be \$.2517 per Margin BDU.

b. Determination of Customer's Margin BDUs

The Customer's Margin BDUs shall be determined as follows: The actual deliveries of gas to the Customer by Company, including not only volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities but also volumes of Customer-owned gas transported to the Customer's load balancing facilities through the Company's facilities, during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Margin BDUs applicable to Customer shall be zero (0).

B. COMMODITY CHARGES FOR SALES AND FOR TRANSPORTATION SERVICE

1. Commodity Charge for Sales Service

The monthly Commodity Charge for Sales Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas sold to the Customer by the Company during the applicable billing cycle.

The rate per Mcf shall be determined as follows and shall be \$3.5036 per Mcf, subject to revision as provided below: (I)

The current components of the rate are as follows:

Purchased Gas Commodity		
Costs, set forth in Rider "A"	\$3.3112/Mcf	(I)
Non Gas Costs	\$0.1924/Mcf	

a. Determination of Rate per Mcf

The rate per Mcf shall be the sum of:

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

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Canceling Forty-Third Revised Page No. 81

1. The net amount per Mcf for recovery of the commodity component of purchased gas costs and for recovery or refund of "E" factor amounts, the "PGCC", as determined in Rider "A" - Section 1307(f) Purchased Gas Costs of this tariff; plus

2. The amount of \$.1924 per Mcf for recovery of non-gas costs.

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made of the commodity component of purchased gas costs (Item 1, above) and the rate per Mcf shall be changed accordingly. The component included in the rate for recovery of non-gas costs shall remain constant until changed in accordance with a procedure, other than a proceeding pursuant to Section 1307(f) of the Public Utility Code, 66 Pa.C.S. Section 1307(f).

2. Commodity Charge for Transportation Service

The monthly Commodity Charge for Transportation Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas transported by the Company to the Customer's load balancing facilities.

The rate per Mcf for transportation of gas under this rate schedule shall be \$0.7724 per Mcf, which includes \$0.1924 for recovery of non-gas costs and \$0.5800 for recovery of purchased gas. (I)

V. SURCHARGE

The non-purchased gas cost Demand Charges and the non-purchased gas cost Commodity Charge for Sales Service and the non-purchased gas cost Commodity Charge for Transportation Service shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff. (I)

VI. AMOUNTS TO BE INCLUDED IN OVER/UNDERCOLLECTION OF GAS COSTS

Purchased gas cost revenues billed under this rate schedule shall be included as revenues for recovery of gas costs for purposes of computing Factor "E" of Company's 1307(f) rate in accordance with procedures set forth in Rider "A" - Section 1307(f) Purchased Gas Costs.

VII. SPECIAL PROVISIONS

Monthly metered Special Provisions A through J contained in the Company's Rate Schedule for Transportation Service shall apply to transportation service under this rate schedule.

VIII. RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease

(I) Indicates Increase

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DISTRIBUTION CORPORATION

Supplement No. 269 to
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One-Hundred-Third Revised Page No. 82
Canceling One-Hundred-Second Revised Page No. 82

RATE SCHEDULE - NGV

NATURAL GAS VEHICLE SERVICE

I. APPLICABILITY

Throughout the territory served under this tariff.

II. AVAILABILITY

Sales Service under this rate schedule is available for use of natural gas by a customer directly in a natural gas motor vehicle ("NGV").

III. NATURE OF SERVICE

Service provided in this rate schedule shall be firm service subject to the curtailment priorities of Rule 26. For curtailment purposes, service under this rate schedule shall be defined as curtailment priority number (6), firm large noncritical commercial and industrial requirements other than requirement for boiler fuel use.

IV. RATE

Rates per 100 cu. Ft. shall be established by the Company on the first day of each calendar month for each of the categories set forth below to compete with alternative vehicle fuels. The rates shall not be less than the 100% load factor base cost of gas, plus the take-or-pay surcharge, plus the surcharge for Transition Cost, plus the incremental operating cost incurred by the Company for operating Company owned NGV compression equipment on a per Ccf basis, if any, plus \$0.01 per cu. ft., plus the state tax adjustment surcharge, and not more than the tailblock rate of the Commercial and Public Authority Service Rate Schedule, including all applicable surcharges, plus the incremental operating cost incurred by the Company for operating Company owned NGV compression equipment on a per Ccf basis, if any.

The 100% load factor base cost of gas shall be \$0.26631 per 100 cu. ft. (I)
(as calculated by adding the purchase gas components of the Load Balancing Service Rates).

Purchased Gas 100% Load Factor Demand	\$0.12315/Ccf	(I)
Cost		
plus		
Purchased Gas Commodity Cost	<u>\$0.33112/Ccf</u>	(I)
Equals		
100% Load Factor Base Cost of Gas	\$0.45427/Ccf	(I)

The incremental operating cost for compression shall be \$0.13436/Ccf.

(D) Indicates Decrease

(I) Indicates Increase

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Canceling One-Hundred-Twenty-Fifth Revised Page No. 83

Natural gas vehicle customers are classified into the following categories:

NGV(1) All natural gas vehicle customers utilizing Company owned filling facilities. A uniform rate shall be established each month within the parameters set forth above, for customers utilizing Company-owned filling facilities.

The minimum NGV(1) rate shall be: \$0.59863/Ccf (I)

The current components of the minimum NGV(1) rate are as follows:

100% load factor base cost of gas:	\$0.45427/Ccf	(I)
Incremental operating cost of Company owned NGV compression equipment:	\$0.13436/Ccf	
Transition Cost Surcharge	\$0.00000/Ccf	
State Tax Adjustment Surcharge	\$0.00000/Ccf	
Minimum allowable Non-Gas cost	\$0.01000/Ccf	

The maximum NGV(1) rate shall be: \$0.90674/Ccf (I)

The current components of the maximum NGV(1) rate are as follows:

Tailblock rate of the Commercial and Public Authority Service Rate schedule:	\$0.77238/Ccf	(I)
Incremental operating cost of Company owned NGV compression equipment:	\$0.13436/Ccf	
State Tax Adjustment Surcharge	\$0.00000/Ccf	

NGV(2) Natural gas vehicle customers utilizing customer owned filling facilities. A uniform rate will be established each month within the parameters set forth above, to customers utilizing customer owned filling facilities.

The minimum NGV(2) rate shall be: \$0.46427/Ccf (I)

The current components of the minimum NGV(2) rate are as follows:

100% load factor base cost of gas:	\$0.45427/Ccf	(I)
Transition Cost Surcharge	\$0.00000/Ccf	
State Tax Adjustment Surcharge	\$0.00000/Ccf	
Minimum allowable Non-Gas cost	\$0.01000/Ccf	

The maximum NGV(2) rate shall be: \$0.77238/Ccf (I)

(D) Indicates Decrease

(I) Indicates Increase

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Canceling One-Hundred-Nineteenth Revised Page No. 84

The current components of the maximum NGV(2) rate are
as follows:

Tailblock rate of the Commercial and Public Authority	
Service Rate schedule:	\$0.77238 /Ccf (I)
State Tax Adjustment Surcharge	\$0.00000/Ccf

V. SURCHARGE

All non-purchased gas cost charges under this rate schedule will be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

VI. AMOUNTS TO BE INCLUDED IN OVER/UNDERCOLLECTION OF GAS COSTS

Purchased gas cost revenues billed under this rate schedule shall be included as revenues for recovery of gas costs for purposes of computing Factor "E" of Company's 1307(f) rate in accordance with procedures set forth in Rider "A" - section 1307(f) Purchased Gas Costs. Purchased gas cost revenues recovered under this rate schedule shall be the 100% load factor base cost of gas as defined above.

VII. RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease

(I) Indicates Increase

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Seventy-Eighth Revised Page No. 93
Canceling Seventy-Seventh Revised Page No. 93

RATE SCHEDULE PSB

PRIORITY STANDBY SERVICE

APPLICABILITY

Throughout the territory served under this tariff.

AVAILABILITY OF SERVICE

Service under this rate schedule is available to all customers under the Residential, Commercial and Public Authority, and SVIS Rate Schedules which enter into a contract for service under this Rate Schedule. A customer will be permitted to enter into a contract, prepared by the Company, for service under this rate schedule, however, only if the Company projects that sufficient volumes of gas will be available to the Company during the period of the customer's contract for Priority Standby Service.

Service under this rate schedule is mandatory for all customers categorized as Priority 1 under the curtailment priorities of Rule 26 who enter into contracts with the Company to receive Transportation Service and who do not have dual or alternate fuel equipment on site which is installed and operable with sufficient amounts of alternate fuel available on site during each winter period of each year commencing on December 1 and ending on March 31 of the following year. Service under this rate schedule is voluntary for all other customers.

NATURE OF SERVICE

Priority standby service shall permit the customer to purchase gas on a firm basis subject to curtailment priorities of Rule 26. The Company will take all reasonable steps to obtain or to maintain gas supplies sufficient to enable the Company to provide reasonably continuous service to each Customer receiving Priority Standby Service.

MONTHLY RATE

The monthly rate shall be \$1.3432 per Mcf, which shall be applied to the total monthly volumes transported by the customer during the month. (I)

The rate shall equal the PGDC portion of the commodity rate applicable to the corresponding sales rate classification.

(D) Indicates Decrease

(I) Indicates Increase

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MONTHLY RATE

The monthly rate shall be \$0.6326 per Mcf, which shall be applied to the (I)
Monthly Volume, as defined below.

MONTHLY VOLUME

The Mcf volume of gas to which the Monthly Rate set forth above shall be
applied, shall be determined for each billing cycle, as set forth below;

1. The volume of gas specified in the Service Agreement under this rate schedule shall be adjusted for each billing cycle by, multiplying such volume, expressed in Mcf, by a fraction. The numerator of the fraction shall be the number of days in the billing cycle applicable to the customer and the denominator shall be thirty (30).
2. If the volume determined under item 1, above, is greater than the sum of the Mcf volume of gas purchased by the customer under rate schedules other than load balancing rate schedules during the billing cycle, the Monthly Rate shall be applied to the difference between: (a) the volume determined under item 1, above, and (b) the Mcf volume of gas purchased by the customer under the rate schedules other than load balancing rate schedules during such billing cycle.
3. If the volume determined under item 1, above, is equal to or less than the Mcf volume of gas purchased by the customer under rate schedules other than load balancing rate schedules during the billing cycle, then the Monthly Volume shall be zero (0) Mcf.

(D) Indicates Decrease

(I) Indicates Increase

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Fifty-Fourth Revised Page No. 100
Canceling Fifty-Third Revised Page No. 100

RATE SCHEDULE FOR MONTHLY METERED TRANSPORTATION SCHEDULE (cont'd)

MONTHLY RATES

Commodity Rates

The commodity rates set forth below contain a component, presently \$0.5800 per Mcf, for recovery of purchased gas costs.

For transportation of gas to Residential Customers, the monthly rate for transportation of gas both within and outside the Commonwealth of Pennsylvania shall be:

\$3.5411 Mcf (I)

For transportation of gas to Commercial and Public Authority Customers, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:

\$2.8794 per Mcf for Small Commercial/Public Authority using not more than 250 Mcf per year (I)

\$2.6355 per Mcf for Small Commercial/Public Authority using greater than 250 Mcf but not more than 1,000 Mcf per year (I)

\$2.2422 per Mcf for Large Commercial/Public Authority (I)

For transportation of gas to Commercial and Public Authority Customers, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

\$2.8794 per Mcf for Small Commercial/Public Authority using not more than 250 Mcf per year (I)

\$2.6355 per Mcf for Small Commercial/Public Authority using greater than 250 Mcf but not more than 1,000 Mcf per year (I)

\$2.2422 per Mcf for Large Commercial/Public Authority (I)

For transportation of gas to Small Volume Industrial Customers, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:

\$2.6522 per Mcf for SVIS Customers (I)

For transportation of gas to Small Volume Industrial Customers, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

\$2.6522 per Mcf for SVIS Customers (I)

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(I) Indicates Increase

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DISTRIBUTION CORPORATION

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RATE SCHEDULE FOR MONTHLY METERED TRANSPORTATION SCHEDULE (cont'd)

For transportation of gas to Intermediate Volume Industrial Customers, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:

\$1.9147 per Mcf for IVIS Customers (I)

For transportation of gas to Intermediate Volume Industrial Customers, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

\$1.9147 per Mcf for IVIS Customers (I)

For transportation of gas to Large Volume Industrial Customers and any entity that is not a Gas Service Customer, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:

\$1.6043 per Mcf (I)

For transportation of gas to Large Volume Industrial Customers and any entity that is not a Gas Service Customer, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

\$1.6043 per Mcf (I)

For transportation of gas to Large Industrial Customers, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:

\$1.1793 per Mcf (I)

For transportation of gas to Large Industrial Customers, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

\$1.1793 per Mcf (I)

Provided, however, that the Company, in its sole discretion, may reduce by contract the portion of the above rates applicable to the Customer that are for recovery of gas or the portion of the rate for recovery of non-gas costs of service if it is reasonably necessary to do so to meet competition from another supplier of energy including gas from another supplier of gas that has constructed, or could construct, facilities to deliver supplies of gas to a MMT Customer of the Company without use of the Company's facilities or another transportation of gas. The Company may also reduce or eliminate the compensation for line losses provided for in Special Provisions paragraph B of this rate schedule in order to meet the competitive circumstances for alternate fuels or bypass situations cited above excluding competition from other Pennsylvania local distribution companies. The Company will reduce the applicable rate only if:

- (a) Either (1) the MMT Customer has facilities in place and operable to use an alternative fuel or obtain gas from an alternative supplier or (2) in the Company's judgment, such facilities would be constructed;

(D) Indicates Decrease

(I) Indicates Increase

E. In the event of interruption or curtailment of transportation service, pursuant to items C and D, above, and during such period of interruption or curtailment, the MMT Customer must sell to the Company all or a portion of the MMT Customer's supply of gas at the higher of (1) the Transportation Service Customer's cost of purchased gas at the point of delivery to the Company or (2) the Company's average cost of purchased gas per Mcf, as determined based upon the Company's Section 1307(f) Rate, which is \$5.9879.

(I)

F. If for any reason (including the default of an MMNGS Supplier), the MMNGS Supplier fails to provide sufficient daily deliveries of natural gas supplies to meet the MMT Customers DDQ pursuant to the terms of MMNGS supply service, and/or MMT Customer's MMNGS Supplier does not provide complete compensation to the Company for services provided under Rate Schedule MMNGS, Special Provision D.3, the Company shall charge the MMT Customer for the deficient daily deliveries under the applicable gas sales rate schedule plus applicable surcharge as set forth in Rate Schedule SB Special Provisions.

(D) Indicates Decrease

(I) Indicates Increase

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Canceling One-Hundred-Sixth Revised Page No.117

E. In the event of interruption or curtailment of transportation service, pursuant to items C and D, above, and during such period of interruption or curtailment, the DMT Service Customer must sell to the Company all or a portion of the DMT Service Customer's supply of gas at the higher of (1) the Transportation Service Customer's cost of purchased gas at the point of delivery to the Company or (2) the Company's average cost of purchased gas per Mcf, as determined based upon the Company's Section 1307(f) Rate, which is \$5.9879. (I)

F. If a Gas Service Customer receiving gas transported by the Company uses less than the amount of gas delivered into the Company's system for transportation to such Customer ("excess deliveries"), the Gas Service Customer receiving gas transported by the Company may use such gas during the banking/balancing period defined below, following which the Company shall have the right, but not the obligation, to purchase remaining excess deliveries of gas from the DMT service Customer at a rate equal to the lowest of (1) the cost at which it was acquired by the DMT Service Customer, including pipeline transportation charges, or (2) the Company's average commodity delivered cost of gas to National Fuel Gas Supply Corporation, or (3) the Company's average commodity cost of locally produced gas during the month when excess deliveries were received by the Company. The cost at which the DMT Service Customer acquired the gas will be determined from such Customer's contract with the supplier or by a sworn affidavit setting forth the Customer's cost of gas, including cost of delivery of such gas to the Company's system. Upon request by the Company, the DMT Service Customer will be required to furnish to the Company the DMT service Customer's choice of (1) a copy of this contract or (2) an affidavit. The banking/balancing period shall be the three billing months after the billing month in which the Company received excess deliveries in behalf of the Customer.

G. "Underdeliveries" are volumes of gas taken from the Company by a Gas Service Customer in excess of the sum of (1) any excess deliveries of the customer at the beginning of the day and (2) the volume of gas delivered to the Company for the customer's account, after adjustment for line losses less volumes of volumes of gas determined to be sales by the Company to the customer. Cumulative underdeliveries, as determined each day, in excess of two percent of the volume of gas delivered by the Company to the customer that day, shall be a sale of gas by the Company to the customer under the applicable rate schedule plus applicable surcharges as set forth in Rate Schedule SB Special Provisions and shall not be recharacterized as transportation service under any circumstances. Cumulative underdeliveries of not more than two percent of the volume of gas delivered to a customer by the Company on any day may be offset by volumes of gas delivered to the Company for the customer's account, after adjustment for line losses, in excess of the volume of gas taken by the customer from the Company on subsequent days within the same billing month.

(D) Indicates Decrease

(I) Indicates Increase

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DISTRIBUTION CORPORATION

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Canceling Sixtieth Revised Page No. 119A

RATE SCHEDULE SATC
SMALL AGGREGATION TRANSPORTATION CUSTOMER SERVICE (Cont'd)

RATES AND CHARGES

A. Customer Transportation Service Rates

The Company will provide transportation services to deliver gas supplies to the SATC Customer(s). The Customer shall be billed the charges for the transportation services rendered for it at the appropriate charges provided herein for which service the SATC Customer qualifies.

The SATC Customer shall pay the following transportation charges for the transportation of gas. The commodity rates set forth below contain a component, presently \$0.04425 per Ccf, for the recovery of purchased gas demand costs and shall be adjusted pursuant to Rider A of the tariff. Such purchased gas costs collected through these rates shall be included as revenues for the recovery of purchased gas costs as specified in Rider A of this tariff. (I)

(D) Indicates Decrease

(I) Indicates Increase

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RATE SCHEDULE SATC
SMALL AGGREGATION TRANSPORTATION CUSTOMER SERVICE (Cont.)

1. Residential Transportation Rates

SATC Customers that meet the qualifications under the Residential Service Rate Schedule classification:

Rates per Residential SATC Customer per Month:

\$14.00

\$0.34036

Basic Service Charge

per 100 cubic feet (I)

(I)

2. Commercial and Public Authority Transportation Rates

SATC Customers that meet the qualifications under the Commercial and Public Authority Service Rate Schedule classification:

a. Rates per Commercial/Public Authority customer per month for "Small" Commercial/Public Customers using not more than 250,000 cubic feet per year:

\$27.00

\$0.27419

Basic Service Charge

per 100 cubic feet

(I)

b. Rates per Commercial/Public Authority customer per month for "Small" Commercial/Public Customers using greater than 250,000 cubic feet but not more than 1,000,000 cubic feet per year:

\$37.00

\$0.24980

Basic Service Charge

per 100 cubic feet

(I)

c. Rates per Commercial/Public Authority customer per month for "Large" Commercial/Public Customers:

\$151.00

\$0.21047

Basic Service Charge

per 100 cubic feet

(I)

(D) Indicates Decrease

(I) Indicates Increase

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Canceling One-Hundred-Seventeenth Revised Page No. 121

RATE SCHEDULE SATC
SMALL AGGREGATION TRANSPORTATION CUSTOMER SERVICE (Cont.)

3. Small Volume Industrial Service Transportation Rates

SATC Customers that meet the qualifications under the Small Volume Industrial Service Rate Schedule classification:

Rates per Small Volume Industrial Service SATC Customer per Month:

\$82.00	Basic Service Charge	
\$0.25147	per 100 cubic feet	(I)

4. Intermediate Volume Industrial Service Transportation Rates

SATC Customers that meet the qualifications under the Intermediate Volume Industrial Service Rate Schedule classification:

Rates per Intermediate Volume Industrial Service SATC Customer per Month:

\$252.00	Basic Service Charge	
\$0.17772	per 100 cubic feet	(I)

B. Miscellaneous Customer Surcharges

1. Residential rate classes shall be subject to surcharges in accordance with Rider F - LIRA Discount Charge as set forth in this tariff.

2. The above non-purchased gas cost SATC rates shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge.

(C) Indicates Change

(D) Indicates Decrease

(I) Indicates Increase

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Canceling Thirty-Sixth Revised Page No. 126

RATE SCHEDULE SATS
SMALL AGGREGATION TRANSPORTATION SUPPLIER SERVICE (Cont.)

C. Total Upstream Capacity Requirements for SATS Suppliers

SATS Suppliers shall be required to provide sufficient firm pipeline transportation and storage capacity to meet the estimated extreme day requirements of their SATC Customer groups as further described below. The SATS Suppliers' estimated extreme day requirements of their SATC Customer Group used for Supplier capacity allocations and requirements shall be based on a sixty-two (62) degree day extreme peak day calculation. The Company shall utilize peaking and temperature swing storage capacity retained by the Company and recovered through SATC rates to provide for any variances between actual and forecasted usage and for any peak delivery requirements for days colder than sixty-two (62) degree days.

Such sufficient pipeline transportation and storage capacity shall be provided through the following means:

1. Released ESS Storage Capacity and Associated EFT Capacity

a. Requirements To Be Met Through ESS Storage

55% of extreme peak day requirements shall be provided through the Company's ESS storage and associated EFT transportation capacity on NFGSC. (I)
Such NFGSC Storage and transmission capacity shall be released to SATS Suppliers at the maximum rate under the pipeline's FERC gas tariff.

b. Initial Assignment of ESS Storage Capacity

In a month a SATS Supplier begins to serve SATC customers, it shall be provided with an initial assignment of storage capacity, based on the percentage set forth at C.1.a. above, to meet the Supplier's requirements for the upcoming winter period. Approximately fifteen days prior to the close of nominations for the month, the Company will calculate the quantity of storage capacity released to match the SATS Supplier's winter requirements based on the number of SATC Customers aggregated by the Supplier. If the initial assignment takes place in a month other than April, the Company will transfer storage gas to the Supplier pursuant to C.1.c below. The SATS Supplier shall be responsible for all taxes and pipeline fees associated with moving or transferring the storage gas to the Company.

(D) Indicates Decrease

(I) Indicates Increase

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Seventy-First Revised Page No. 127
Canceling Seventieth Revised Page No. 127

RATE SCHEDULE SATS
SMALL AGGREGATION TRANSPORTATION SUPPLIER SERVICE (Cont.)

c. Additional Assignments of ESS Storage Capacity

Approximately fifteen days prior to the close of nominations for each month, the Company will recalculate the quantity of storage capacity released to match the SATS Supplier's revised winter requirements based on the number of SATC Customers aggregated by the Supplier. If additional SATC Customers join a SATS Supplier's SATC Customer Group, the Company will release additional capacity as required, based on the percentage set forth at C.1.a. above. In addition, the SATS Supplier will be required to pay the Company for storage gas transferred and all taxes and pipeline fees associated with moving or transferring the storage gas to the Supplier. The storage gas transfer rate shall be the sum of (1) the higher of the Company's average cost of gas based upon the Company's Section 1307f rate, or the DMI for the first day of month in which gas is transferred plus all transportation costs to the Company's City Gate, plus (2) the demand Transfer Recovery Rate ("DTR Rate"). The DTR rate shall equal the per Mcf System Average Unrecovered Demand Charge revenue beginning in the month of April through the initial month that storage capacity is released to the Supplier. The System Average Unrecovered demand Charge Revenue shall equal the sum of the differences between the average demand charge revenues and the average fixed demand costs beginning the month of April through the initial month that storage capacity is released to the Supplier.

The DTR by month shall be as follows:

Capacity Transfer <u>Month</u>	DTR <u>\$/Mcf</u>	
April	\$0.00	
May	\$0.00	
June	\$0.00	
July	\$0.00	
August	\$0.00	
September	\$0.00	
October	\$0.00	
November	\$0.64	(I)
December	\$1.05	(I)
January	\$0.94	(I)
February	\$0.49	(I)
March	\$0.00	

(D) Indicates Decrease

(I) Indicates Increase

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Canceling Seventy-Third Revised Page No. 131

RATE SCHEDULE SATS
SMALL AGGREGATION TRANSPORTATION SUPPLIER SERVICE (Cont.)

2. Released Transmission Capacity Not Included in SATC
Transportation Rates

45% of extreme peak day requirements is to be provided by the release of pipeline capacity upstream of NFGSC and the release of associated EFT transportation capacity on NFGSC which is not included in transportation rates. All such capacity shall be released to SATS Suppliers, and SATS Suppliers shall take such released capacity, at the maximum rate under the pipeline's FERC gas tariff. The actual pipeline capacity path upstream of NFGSC to be released to the Supplier by the Company shall be designated by the Company from its available capacity. The Company will attempt to accommodate a Supplier's request for particular capacity on a first-come first-serve basis. (D)

As an alternative to the above, the Company may designate an alternative capacity path(s) from its available capacity. The capacity release rate for the pipeline capacity path released to the Supplier shall be \$7.0946/Dth which equals the weighted average demand cost of upstream capacity, however, capacity released on NFGSC will be released at the maximum rate under NFGSC's FERC gas tariff. The Company will post a listing of the alternative capacity path(s) designated, including the associated quantity of capacity, on its web site. (D)

For capacity termination notices, prior to the termination notice date of any capacity contract in this Section C.2., the Company will issue a request for proposals to qualified Suppliers under this tariff to determine if the Company should terminate, renew, or replace such contract, in whole or in part. The Company will terminate a proportionate share of the capacity contract if: (1) Suppliers demonstrate that they will provide comparable firm capacity to serve the Company's core customers, (2) the Suppliers agree to assign such comparable capacity at the contracted price to the Company upon Company request if such capacity is required to meet supply requirements of SATC Customers due to the termination of the SATS Supplier pursuant to Section H.1. or if the Supplier has reduced the level of delivery requirements from the previous periods requirements, and 3) the Commission approves such comparable capacity. Comparable capacity must have firm rights for at least the seven (7) winter months, and such capacity must have primary delivery rights into available primary receipt rights on NFGSC held by the Company. Comparable capacity must have firm capacity rights sufficient in volume and duration (with renewal rights) to serve the customers to be served by the SATS Supplier. The Company will post a listing of capacity contracts, including the associated quantity of capacity, that it determines to be of critical status on its web site.

(D) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

Effective: August 1, 2024

NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

Seventy-Seventh Revised Page No. 146G
Canceling Seventy-Sixth Revised Page No. 146G

E. In the event of interruption or curtailment of transportation service, pursuant to items C and D, above, and during such period of interruption or curtailment, the DMLMT Service customer must sell to the Company all or a portion of the DMLMT Service Customer's supply of gas at the higher of (1) the Transportation Service Customer's cost of purchased gas at the point of delivery to the Company or (2) the Company's average cost of purchased gas per Mcf, as determined based upon the Company's Section 1307(f) Rate which is \$5.9879.

(I)

F. If a Gas Service Customer receiving gas transported by the Company uses less than the amount of gas delivered into the Company's system for transportation to such Customer ("excess deliveries"), the Gas Service Customer receiving gas transported by the Company may use such gas during the banking/balancing period defined below, following which the Company shall have the right, but not the obligation, to purchase remaining excess deliveries of gas from the DMLMT Service Customer at a rate equal to the lowest of (1) the cost at which it was acquired by the DMLMT Service Customer, including pipeline transportation charges, or (2) the Company's average commodity delivered cost of gas to National Fuel Gas Supply Corporation, or (3) the Company's average commodity cost of locally-produced gas during the month when excess deliveries were received by the Company. The cost at which the DMLMT Service Customer acquired the gas will be determined from such Customer's contract with the supplier or by a sworn affidavit setting forth the Customer's cost of gas, including cost of delivery of such gas to the Company's system. Upon request by the Company, the DMLMT service Customer will be required to furnish to the Company the DMLMT Service Customer's choice of (1) a copy of this contract or (2) an affidavit. The banking/balancing period shall be the three billing months after the billing month in which the Company received excess deliveries in behalf of the Customer.

G. "Underdeliveries" are volumes of gas taken from the Company by a Gas Service Customer in excess of the sum of (1) any excess deliveries of the customer at the beginning of the day and (2) the volume of gas delivered to the Company for the customer's account, after adjustment for line losses less volumes of gas determined to be sales by the Company to the customer. Cumulative underdeliveries, as determined each day, in excess of two percent of the volume of gas delivered by the Company to the customer that day, shall be a sale of gas by the Company to the customer under the applicable rate schedule plus applicable surcharges as set forth in Rate Schedule SB Special Provisions and shall not be recharacterized as transportation service under any circumstances. Cumulative underdeliveries of not more than two percent of the volume of gas delivered to a customer by the Company on any day may be offset by volumes of gas delivered to the Company for the customer's account, after adjustment for line losses, in excess of the volume of gas taken by the customer from the Company on subsequent days within the same billing month.

(D) Indicates Decrease

(I) Indicates Increase

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9

One-Hundred-Fourth Revised Page No. 147
Canceling One-Hundred-Third Revised Page No. 147

RIDER A
SECTION 1307(F) PURCHASED GAS COSTS
PROVISION FOR RECOVERY OF PURCHASED GAS COSTS

Rates for each Mcf (1,000 cubic feet) of gas supplied under Residential, Low Income Residential Assistance Service, Commercial and Public Authority, Commercial and Public Authority Load Balancing Service ("LBS"), Small Volume Industrial, Intermediate Volume Industrial, Intermediate Volume Industrial LBS, Large Industrial, Large Industrial LBS, Large Volume Industrial, Large Volume Industrial LBS and Natural Gas Vehicle Service rate schedules of this tariff, shall include \$3.3112 per Mcf for recovery of purchased gas commodity costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. (I)

Rates for each Mcf (1,000 cubic feet) of gas supplied under Residential, Commercial and Public Authority, Small Volume Industrial Service, Intermediate Volume Industrial, Large Volume Industrial Service, Large Industrial Service and Standby Service rate schedules of this tariff, shall include \$2.1744 per Mcf for recovery of purchased gas demand costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. (I)

Rates for each Mcf (1,000 cubic feet) of gas transported under the Small Aggregation Transportation Customer Rate Schedule shall include \$0.4425 per Mcf for the recovery of purchased gas demand costs. (I)

Such rates for gas service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of purchased gas costs.

The amounts per Mcf for recovery of purchased gas costs (commodity and demand) included in rates under each rate schedule of the tariff are as follows:

	Distribution		Gas Adjustment	Natural Gas	
	<u>Total</u>	<u>Charges</u>	<u>Charge</u>	<u>Supply Charge</u>	
Residential	\$5.9281	\$0.4425	\$ (0.0479)	\$5.5335	(I)
Low Income Residential Assistance Service	\$5.9281	\$0.4425	\$ (0.0479)	\$5.5335	(I)
Commercial/Public Authority	\$5.9281	\$0.4425	\$ (0.0479)	\$5.5335	(I)
Small Volume Industrial	\$5.9281	\$0.4425	\$ (0.0479)	\$5.5335	(I)
Intermediate Volume Industrial	\$5.9281	\$0.4425	\$ (0.0479)	\$5.5335	(I)
Large Volume Industrial	\$5.9281	\$0.4425	\$ (0.0479)	\$5.5335	(I)
Large Industrial	\$5.9281	\$0.4425	\$ (0.0479)	\$5.5335	(I)
Standby	\$0.6326				(I)
Priority Standby	\$1.3432				(I)
Small Aggregation Transportation Customer Rate Schedule	\$0.4425	\$0.4425			(I)

(I) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

Effective: August 1, 2024

Rider G
Merchant Function Charge (MFC) Rider

Applicability:

The Merchant Function Charge (MFC) shall be added to the Natural Gas Supply Charge and Gas Adjustment Charge of Residential, LIRAS, Commercial and Public Authority, SVIS, IVIS, LVIS and LIS rate schedules.

Such charges shall be updated quarterly and effective each February 1, May 1, August 1, and November 1 of the year. The charge will also be updated whenever there is a change to the Sales Service Rate Customer Charge, Distribution Charge, Natural Gas Supply Charge or Gas Adjustment Charge.

Calculation of Rate:

For customers receiving service in the Residential classification, the MFC shall equal 1.8032% times the Natural Gas Supply Charge and the Gas Adjustment Clause as calculated for Rider A.

The current Residential MFC Charge is:

Natural Gas Supply Charge per Mcf	\$0.0998	(I)
Gas Adjustment clause (E-Factor) per Mcf	\$(0.0009)	(I)
Total Residential MFC per Mcf	\$0.0989	(I)

For customers receiving service in the Non-Residential classifications, the MFC shall equal 0.3398% times the Natural Gas Supply Charge and Gas Adjustment Clause as calculated for Rider A.

The current Non-Residential MFC Charge is:

Natural Gas Supply Charge per Mcf	\$0.0188	(I)
Gas Adjustment clause (E-Factor) per Mcf	\$(0.0002)	(I)
Total Non-Residential MFC per Mcf	\$0.0186	(I)

(D) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

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NATIONAL FUEL GAS
DISTRIBUTION CORPORATION

Supplement No. 269 to
Gas - Pa. P.U.C. No. 9
Fifty-Second Revised Page No. 169
Canceling Fifty-First Revised Page No. 169

Rider H
Gas Procurement Charge (GPC)

APPLICABILITY

Effective June 1, 2013, the Gas Procurement Charge will be included in the Natural Gas Supply Charge of Residential, LIRAS, Commercial and Public Authority, SVIS, IVIS, LVIS and LIS rate schedules.

The charge is designed to recover the costs of procuring natural gas pursuant to 52 Pa. Code §62.223. The natural gas procurement costs included in the GPC charge will only be updated in a base rate case.

The GPC to be included in the Natural Gas Supply Charge shall be \$0.1149 / Mcf and is not reconcilable.

	Residential (¢ per 100 cubic feet)	Non Residential (¢ per 100 cubic feet)	
Price To Compare Component			
Natural Gas Supply Charge			
Purchased Gas Cost Component (Rider A)	55.335	55.335	(I)
Merchant Function Charge associated with Natural Gas Supply Charge (Rider G)	0.998	0.188	(I)
Gas Procurement Charge (Rider H)	<u>1.149</u>	<u>1.149</u>	
Subtotal Natural Gas Supply Charge	57.482	56.672	(I)
Gas Adjustment Charge			
Purchased Gas Cost Component (Rider A)	(0.479)	(0.479)	(I)
Merchant Function Charge associated with Gas Adjustment Charge (Rider G)	(0.009)	(0.002)	(I)
Subtotal Gas Adjustment Charge	(0.488)	(0.481)	(I)
Total Price To Compare	<u>56.994</u>	<u>56.191</u>	(I)

(D) Indicates Decrease

(I) Indicates Increase

Issued: January 31, 2024

Effective: August 1, 2024

National Fuel Gas Distribution Corporation
Pennsylvania Division
Computation of Weighted Average Cost of Capacity
for Mandatory Release Capacity Under the Rate Schedule
Small Aggregation Transportation Supplier Service
On or After August 1, 2024

Computation Year: Twelve Months Ended July 2025

	Total Pa. Monthly Capacity Dth (A)	Applicable # of Months in Rate Yr (B)	Total Pa Annual Capacity Dth (C)	Demand Rate \$/Dth (D)	Total Demand Cost (E=DxC)
Texas Eastern	10,000	12	120,000	\$ 6.3770	\$ 765,240
TGP 1-4	8,750	12	105,000	\$ 12.6232	\$ 1,325,436
TGP 4-4	65,250	12	783,000	\$ 4.5022	\$ 3,525,223
Columbia - FTS	1,748	12	20,976	\$ 10.1620	\$ 213,158
Columbia FSS Demand				\$ 2.8230	\$ 623,894
Columbia FSS Capacity				\$ 0.0513	\$ 347,217
Columbia SST	18,417		165,756	\$ 10.0500	\$ 1,665,848
Total	104,165		1,194,732		8,466,016
Total Mandatory Release Capacity (Dth)					1,194,732
Weighted Average Cost of Capacity (\$/Dth)					\$ 7.0861

Columbia Annual Capacity is 6 months at 18,417 and 6 months at 9,209.

National Fuel Gas Distribution Corporation

Pennsylvania Division

Calculation of Demand Transfer Recovery Rate

Storage Cycle April 2024 - March 2025

Month	Total Normal Sales Load Pattern (MMcf)	Demand Charge Rate	Demand Charge Revenue (\$000)	Fixed Demand Cost (\$000)	Demand Cost (Under) Over Recovery (\$000)	Cumulative Demand Cost (Under) Over Recovery (\$000)	Storage Transfer Volumes @ 55% of Peak Day Requirements (MMcf)	Demand Cost in Storage Rate	Demand Cost Recovered in Storage Rate (\$000)	(Under) Over Recovery of Demand Cost (\$000)	Demand Transfer Recovery Rate	
1 Apr	2,476.68	\$ 2.31	\$ 5,721.12	\$ 4,622.31	\$ 1,098.81	\$ 1,098.81	977.29	\$ 2.62	\$ 2,557.48	\$ 3,656.29	\$ -	Apr
2 May	1,279.71	\$ 2.31	\$ 2,956.12	\$ 4,622.31	\$ (1,666.19)	\$ (567.39)	1,954.59	\$ 2.62	\$ 5,114.96	\$ 4,547.57	\$ -	May
3 Jun	647.70	\$ 2.31	\$ 1,496.19	\$ 4,622.31	\$ (3,126.12)	\$ (3,693.51)	2,931.88	\$ 2.62	\$ 7,672.44	\$ 3,978.93	\$ -	Jun
4 Jul	403.52	\$ 2.31	\$ 932.13	\$ 4,622.31	\$ (3,690.18)	\$ (7,383.69)	3,909.17	\$ 2.62	\$ 10,229.92	\$ 2,846.23	\$ -	Jul
5 Aug	365.47	\$ 2.62	\$ 956.40	\$ 4,622.31	\$ (3,665.91)	\$ (11,049.60)	4,886.47	\$ 2.62	\$ 12,787.40	\$ 1,737.80	\$ -	Aug
6 Sep	375.66	\$ 2.62	\$ 983.06	\$ 4,622.31	\$ (3,639.25)	\$ (14,688.85)	5,863.76	\$ 2.62	\$ 15,344.88	\$ 656.03	\$ -	Sep
7 Oct	720.72	\$ 2.62	\$ 1,886.05	\$ 4,622.31	\$ (2,736.26)	\$ (17,425.12)	6,841.06	\$ 2.62	\$ 17,902.36	\$ 477.24	\$ -	Oct
8 Nov	1,608.59	\$ 2.62	\$ 4,209.53	\$ 4,622.31	\$ (412.78)	\$ (17,837.90)	5,472.84	\$ 2.62	\$ 14,321.89	\$ (3,516.01)	\$ 0.64	Nov
9 Dec	2,835.86	\$ 2.62	\$ 7,421.16	\$ 4,622.31	\$ 2,798.85	\$ (15,039.05)	4,104.63	\$ 2.62	\$ 10,741.42	\$ (4,297.64)	\$ 1.05	Dec
10 Jan	3,789.54	\$ 2.62	\$ 9,916.85	\$ 4,622.31	\$ 5,294.54	\$ (9,744.51)	2,736.42	\$ 2.62	\$ 7,160.94	\$ (2,583.57)	\$ 0.94	Jan
11 Feb	3,864.07	\$ 2.62	\$ 10,111.88	\$ 4,622.31	\$ 5,489.57	\$ (4,254.95)	1,368.21	\$ 2.62	\$ 3,580.47	\$ (674.48)	\$ 0.49	Feb
12 Mar	3,392.28	\$ 2.62	\$ 8,877.26	\$ 4,622.31	\$ 4,254.95	\$ -	-	\$ 2.62	\$ -	\$ -	\$ -	Mar
	21,759.79		\$ 55,467.74	\$ 55,467.74								

Pennsylvania Division - Design Day Capacity	2024-2025

Firm Requirements	Dth/day
Retail 74 DD (NFGDC Provided)	279,794
Unbundled Aggregated @ 62 DD	21,729
Unbundled Aggregated @ 12 DD	4,142
Priority Standby @ 52 DD	5,805
MMT Imbalance	28,361
DMT Imbalance	1,339
Local Production Balancing	2,029
Contingency Capacity	7,677
Total Forecasted Requirements	350,876

Intermediate Capacity	
NFGSC EFT - E00528	291,130
NFGSC EFT - E11178	9,000
NFGSC EFT E11969	10,000
NFGSC EFT - E12642	10,000
NFGSC FT - 31,000 Receipt	30,746
Total Intermediate Capacity	350,876

Upstream Pipeline	
COL FTS	1,748
TGP FT-A Z0, L, 4 to 4 (74,000 less SATS)	65,432
TGP FT-A Z0 to Z4 SATS	8,568
TET FT1- (M2 to M2)	10,000
Total Upstream Pipeline	85,748

Deliveries from Storage	
NFGSC ESS-1 (187,563 Less SATS)	177,587
NFGSC ESS-1 SATS	9,976
COL FSS	18,417
NFGSC FSS (19 - day)	10,666
Total Storage Deliveries	230,646

* NFGSC Fuel Rate	0.82%

Winter Gas Calls	35,628
Total NFGSC Citygate	35,628
Total (Pipeline + Storage + Citygate)	352,022
Less NFGSC Fuel non-NFSTOR*	(1,146)
Total Upstream FT + Storage + App (net NFGSC fuel)	350,876

Total Capacity Available	350,876
Total Capacity Required	350,876

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

National Fuel Gas Distribution Corporation hereby provides its Proposed Reliability Plan as well as its Supply Plan, as required by Sections 1317(c) and (d) of the Public Utility Code:

Distribution's projected design day requirements for customers utilizing the system during the application period of August 1, 2024 through July 31, 2025 are provided in PGC Exhibit Nos. 15, 24, 26-A, 26-B and 30. Distribution's projected winter seasonal requirements for customers utilizing the system are provided in PGC Exhibit No. 15.

Distribution's capacity that ensures the deliverability of the supplies necessary to meet the Company's projected design day and seasonal requirements is provided in PGC Exhibit Nos. 4, 4-A and 8. Distribution's plan for natural gas supply acquisition is set forth in PGC Exhibit No. 8.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

National Fuel Gas Distribution Corporation hereby provides as Attachment A its supply mix summaries for the twelve-month period ended November 30, 2023.

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Dec-22

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$6,980,114	1,312,850	\$ 5.32
First of Month	\$3,878,070	597,758	\$ 6.49
Forward	\$3,892,967	544,414	\$ 7.15
Local Production	\$48,224	10,217	\$ 4.72
Total	\$14,799,375	2,465,239	\$ 6.00

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Jan-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$905,543	318,119	\$ 2.85
First of Month	\$3,331,746	752,773	\$ 4.43
Forward	\$3,925,553	548,700	\$ 7.15
Local Production	\$32,936	10,888	\$ 3.03
Total	\$8,195,779	1,630,480	\$ 5.03

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Feb-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$1,040,270	450,422	\$ 2.31
First of Month	\$1,232,192	455,924	\$ 2.70
Forward	\$3,545,661	495,600	\$ 7.15
Local Production	\$19,373	9,824	\$ 1.97
Total	\$5,837,495	1,411,770	\$ 4.13

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Mar-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$1,059,831	453,861	\$ 2.34
First of Month	\$1,272,198	628,773	\$ 2.02
Forward	\$1,684,540	235,600	\$ 7.15
Local Production	\$14,709	8,958	\$ 1.64
Total	\$4,031,278	1,327,192	\$ 3.04

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Apr-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$1,707,111	937,499	\$ 1.82
First of Month	\$1,657,088	930,000	\$ 1.78
Forward	\$544,800	240,000	\$ 2.27
Local Production	\$12,891	9,620	\$ 1.34
Total	\$3,921,889	2,117,119	\$ 1.85

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
May-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$1,163,926	755,258	\$ 1.54
First of Month	\$1,402,174	790,403	\$ 1.77
Forward	\$562,960	248,000	\$ 2.27
Local Production	\$13,670	10,372	\$ 1.32
Total	\$3,142,730	1,804,033	\$ 1.74

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Jun-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$824,296	585,650	\$ 1.41
First of Month	\$847,387	548,898	\$ 1.54
Forward	\$544,755	239,980	\$ 2.27
Local Production	\$10,858	9,907	\$ 1.10
Total	\$2,227,295	1,384,435	\$ 1.61

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Jul-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$960,543	650,128	\$ 1.48
First of Month	\$780,176	511,500	\$ 1.53
Forward	\$557,212	245,468	\$ 2.27
Local Production	\$11,686	10,296	\$ 1.14
Total	\$2,309,618	1,417,392	\$ 1.63

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Aug-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$759,014	652,625	\$ 1.16
First of Month	\$741,038	514,165	\$ 1.44
Forward	\$562,960	248,000	\$ 2.27
Local Production	\$10,833	11,157	\$ 0.97
Total	\$2,073,845	1,425,947	\$ 1.45

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Sep-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$992,676	716,964	\$ 1.38
First of Month	\$601,277	540,000	\$ 1.11
Forward	\$544,800	240,000	\$ 2.27
Local Production	\$9,337	11,317	\$ 0.83
Total	\$2,148,089	1,508,281	\$ 1.42

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Oct-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$1,404,617	962,041	\$ 1.46
First of Month	\$1,110,036	798,250	\$ 1.39
Forward	\$562,960	248,000	\$ 2.27
Local Production	\$27,291	25,893	\$ 1.05
Total	\$3,104,904	2,034,184	\$ 1.53

National Fuel Gas Distribution Corporation
Supply Mix Portfolio
Nov-23

Description	Total Cost \$	Total Quantity Dths	Avg Rate \$/Dth
Daily	\$1,708,832	803,137	\$ 2.13
First of Month	\$762,083	385,500	\$ 1.98
Forward	\$707,700	240,000	\$ 2.95
Local Production	\$21,605	14,490	\$ 1.49
Total	\$3,200,219	1,443,127	\$ 2.22

Criteria of a Sound Rate Structure¹

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.
2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.
3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare “The best tax is an old tax.”)

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
 - (a) in the control of the total amounts of service supplied by the company; and
 - (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).
5. Reflection of all the present and future private and social costs and benefits occasioned by a service’s provision (i.e., all internalities and externalities).
6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer’s demands can be diverted away uneconomically from an incumbent by a potential entrant).
7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).
8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

¹ Principles of Public Utility Rates, Second Edition, Bonbright, James C., Albert L. Danielsen, David R. Kamerschen; Public Utilities Reports, Inc., 1988, pages 383-384.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.
10. Freedom from controversies as to proper interpretation.

**National Fuel Gas Distribution Corporation
Pennsylvania Division
Calculation of PSB Service Rates and SB Service Rates**

Peak Capacity Requirement (52DD)	5,520
PLUS PAD Shrink @.15	<u>8</u>
MCF (See PGC Exhibit No. 26-B)	5,528
BTU	1.051
Dth	5,810
Upstream Capacity Rate	\$ 7.0946 /Dth
Annualized Upstream Capacity Amount	\$ 494,620
EFT Rate	\$ 8.9534
Annualized EFT Amount	\$ 624,212
Total Annualized Amount	\$ 1,118,832
Normalized Annual Priority Standby (PSB) Volumes	832,968 Mcf
Calculated PSB Rate	\$ 1.3432 \$/Mcf
Average Sales Load Factor	47.0958%
Standby (SB) Service Rate	\$ 0.6326 \$/Mcf

National Fuel Gas Distribution Corporation
Pennsylvania Division
GAS COST MANAGEMENT PLAN

Volatility mitigation through price diversification of gas supplies.

- I.** Forward pricing: Fix or cap approximately 12% of forecasted winter (November – March) demand requirements. Pricing will be established over the preceding summer (April – October).
- II.** Storage: Approximately 40% of winter demand requirements are served from storage, these supplies are priced at a weighted average cost of storage gas.
- III.** Monthly Pricing: Approximately 24% of winter and 50% of summer forecasted demand requirements shall be priced at a mix of index and bid week negotiated (cash) prices.
- IV.** Daily Pricing: Approximately 24% of winter and 50% of summer forecasted demand requirements shall be priced at a mix of index and negotiated (cash) prices.

	Winter	Summer
Forward	12%	0%
Storage	40%	0%
Monthly	24%	50%
Daily	24%	50%
	100%	100%

The timing of when to fix or cap prices, and the percentages indicated above, are general guidelines based on normal weather and operating conditions. Adjustments may be necessary to accommodate operational requirements and unanticipated events.

Revision Date: November 1, 2018

National Fuel Gas Distribution Corporation
Pennsylvania Division
GAS COST MANAGEMENT PLAN
Effective: April 1, 2025

**Volatility mitigation through price diversification
(100% of forecasted monthly purchases)**

- I.** Forward pricing: Winter fixed price or caps for approximately 12% of forecasted winter (November – March) demand requirements. Prices for these winter delivery quantities will be established over the preceding summer (April – October). Summer fixed price for approximately 15%-20% of forecasted summer (April – October) demand requirements and storage fill requirements. Prices for these summer delivery quantities will be established over the preceding summer (April – October).
- II.** Storage: Approximately 40% of winter demand requirements are served from storage, these supplies are priced at the previous summer's (April – October) average purchase price.
- III.** Monthly Pricing: Approximately 24% of winter and 30%-35% of summer forecasted demand requirements shall be priced at a mix of index and bid week negotiated (cash) prices.
- IV.** Daily Pricing: Approximately 24% of winter and 50% of summer forecasted demand requirements shall be priced at a mix of index and negotiated (cash) prices.

	Winter	Summer
Forward	12%	15-20%
Storage	40%	0%
Monthly	24%	30-35%
Daily	24%	50%
	100%	100%

The timing of when to fix or cap prices, and the percentages indicated above, are general guidelines based on normal weather and operating conditions. Adjustments may be necessary to accommodate operational requirements and unanticipated events.

National Fuel Gas Distribution Corporation
Pennsylvania Division
Commodity
On and After November 1, 2023

		Initial Filing	Nov. 23 quarterly	
		Aug-23	Nov-23	Nov-23
		(A)	(B)	(C=B-A)
(1)	Commodity - C factor \$	59,397,938	60,485,785	1,087,847
(2)	Quarterly - Adjustment Change - Page 7		(476,392)	(476,392)
(3 = 1+ 2)	Total Change		60,009,393	611,455
(4)	Volumes - Mcf	21,708,981		21,708,981
(5 = 3/4)	Quarterly C-factor change	2.7361		0.0282
(6=5)	Prior quarterly rate			2.7361
(7= 5+6)	Sub total C Factor Rate - \$/Mcf	2.7361		2.7643
(8)	Annual O/(U) - \$ - E-Factor	26,791,987	26,097,749	(694,238)
(9=8/4)	Over/Under collection change	1.2341		(0.0320)
(10=9)	Prior quarterly rate			1.2341
(11=9+10)	O/(U) Rate - \$/Mcf	1.2341		1.2021
(12)	Storage - \$/Mcf	\$ 0.0051		\$ (0.0007)
(13=7-11+12)	Total rate - \$/Mcf	1.5071		1.5615

National Fuel Gas Distribution Corporation
Pennsylvania Division
Demand - NGS
On and After November 1, 2023

		Initial Filing	Nov. 23 quarterly	
		Aug-23	Nov-23	Nov-23
		(A)	(B)	(C-=B-A)
(1)	Demand - NGS factor \$	29,592,195	39,502,770	9,910,575
(2)	Quarterly - Adjustment Change - Page 5		529,985	529,985
(3 = 1+ 2)	Total Change		40,032,755	10,440,560
(4)	Volumes - Mcf	21,708,981		21,708,981
(5 = 3/4)	Quarterly C-factor change	1.3631		0.4809
(6=5)	Prior quarterly rate			1.3631
(7= 5+6)	Sub total C Factor Rate - \$/Mcf	1.3631		1.8440
(8)	Annual O/(U) - \$ - E-Factor	(1,259,998)	(1,972,167)	(712,169)
(9=8/4)	Over/Under collection change	(0.0580)		(0.0328)
(10=9)	Prior quarterly rate			(0.0580)
(11=9+10)	O/(U) Rate - \$/Mcf	(0.0580)		(0.0908)
(12=7-11)	Total rate - \$/Mcf	1.4211		1.9348

National Fuel Gas Distribution Corporation
Pennsylvania Division
Demand - DC
On and After November 1, 2023

		Initial Filing	Nov. 23 quarterly	
		Aug-23	Nov-23	Nov-23
		(A)	(B)	(C=B-A)
(1)	Demand - DC factor \$	6,461,604	8,497,530	2,035,926
(2)	Quarterly - Adjustment Change - Page 6		39,141	39,141
(3 = 1+ 2)	Total Change		8,536,671	2,075,067
(4)	Volumes - Mcf	23,651,935		23,651,935
(5 = 3/4)	Quarterly C-factor change	0.2732		0.0877
(6=5)	Prior quarterly rate			0.2732
(7= 5+6)	Sub total C Factor Rate - \$/Mcf	0.2732		0.3609
(8)	Annual O/(U) - \$ - E-Factor	(376,721)	(437,630)	(60,909)
(9=8/4)	Over/Under collection change	(0.0159)		(0.0026)
(10=9)	Prior quarterly rate			(0.0159)
(11=9+10)	O/(U) Rate - \$/Mcf	(0.0159)		(0.0185)
(12=7-11)	Total rate - \$/Mcf	0.2891		0.3794

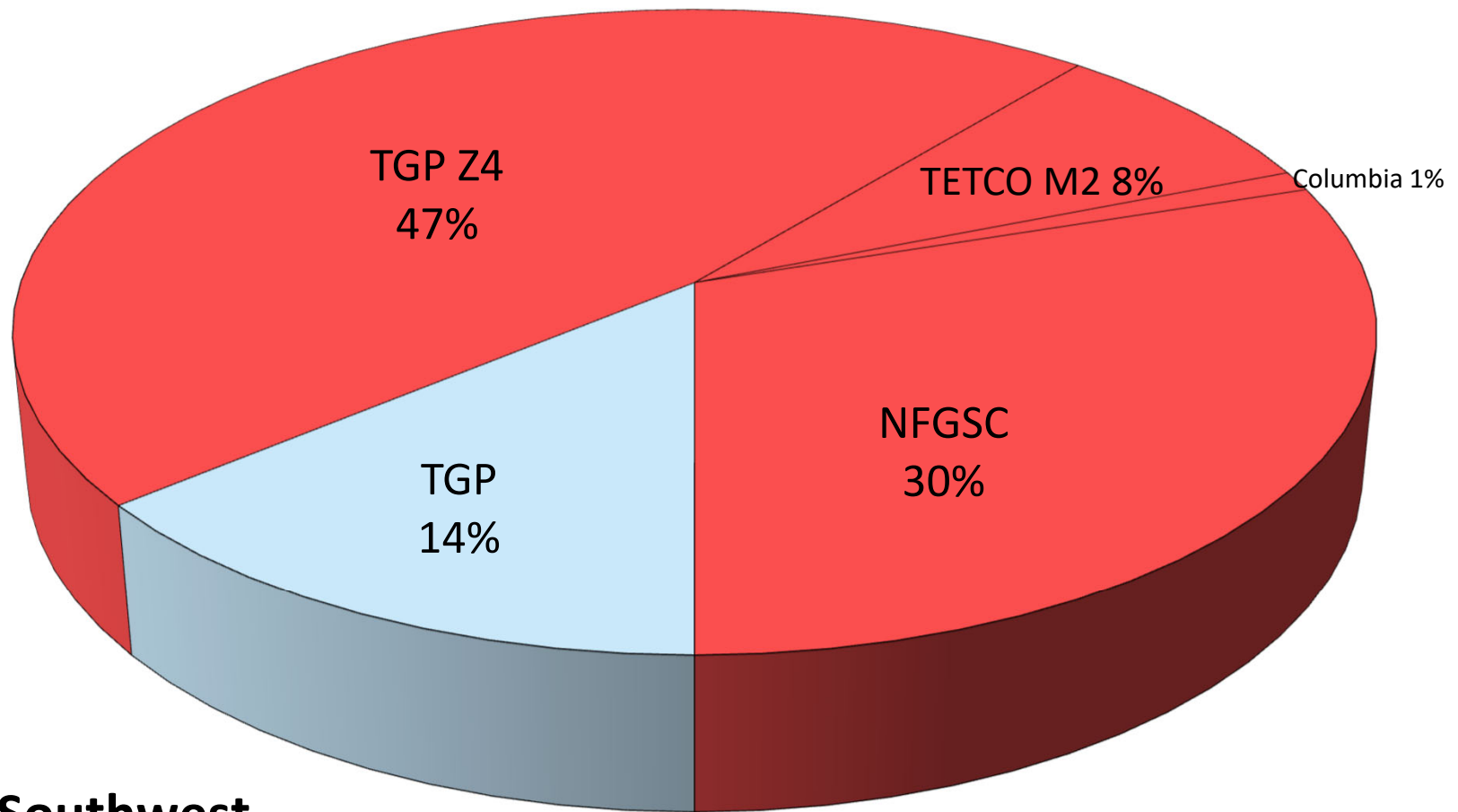
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
Pennsylvania Division
Calculation of Interest on Storage Injections / Withdrawals (C Factor - (Passback) / Recovery)
Twelve Months Ended July 2024

<u>Month</u>		<u>Injections</u>	<u>Withdrawals</u>	<u>Rate</u>	<u>Cost Charged</u>	<u>Cost Paid</u>	<u>Storage</u>	<u>Interest</u>	<u>Interest</u>	<u>Gross</u>
				<u>Differential</u>	<u>Through PGC</u>	<u>By Distribution</u>	<u>(Net Paid) /</u>	<u>Weight</u>	<u>Rate</u> ¹	<u>Storage Interest</u>
		Mcf (1)	Mcf (2)	\$/Mcf (3)	\$ (4=2x3)	\$ (5=1x3)	\$ (6=4+5)	(7)	% (8)	\$ (9=[6x(7x8)])
August 2023	Closed	975,930	14,830	\$4.5022	66,768	(4,393,832)	(4,327,064)	12 / 12	3.25%	\$ (140,630)
September	Closed	1,169,912	14,590	\$4.5022	65,687	(5,267,178)	(5,201,491)	11 / 12	3.25%	\$ (154,961)
October	Open	838,121	-	\$4.1072	-	(3,442,331)	(3,442,331)	10 / 12	3.25%	\$ (93,230)
November	Open	-	550,251	\$4.1072	2,259,991	-	2,259,991	9 / 12	3.25%	\$ 55,087
December	Open	-	1,147,071	\$4.1072	4,711,250	-	4,711,250	8 / 12	3.25%	\$ 102,077
January 2024	Open	-	1,933,801	\$4.1072	7,942,507	-	7,942,507	7 / 12	3.25%	\$ 150,577
February	Open	-	1,495,493	\$4.1072	6,142,289	-	6,142,289	6 / 12	3.25%	\$ 99,812
March	Open	-	1,693,306	\$4.1072	6,954,746	-	6,954,746	5 / 12	3.25%	\$ 94,179
April	Open	233,722	-	\$4.1072	-	(959,943)	(959,943)	4 / 12	3.25%	\$ (10,399)
May	Open	1,198,831	-	\$4.1072	-	(4,923,839)	(4,923,839)	3 / 12	3.25%	\$ (40,006)
June	Open	1,156,021	-	\$4.1072	-	(4,748,009)	(4,748,009)	2 / 12	3.25%	\$ (25,718)
July	Open	1,172,988	-	\$4.1072	-	(4,817,696)	(4,817,696)	1 / 12	3.25%	\$ (13,048)
TOTAL		6,745,525	6,849,342		\$ 28,143,238	\$ (28,552,828)	\$ (409,590)			\$ 23,740
Estimated storage interest expense / (income) due to / (from) PGC customers										\$ 23,740
PGC Volumes										22,556,240
PGC (Passback) / Recovery Rate \$/Mcf										(\$0.0007)

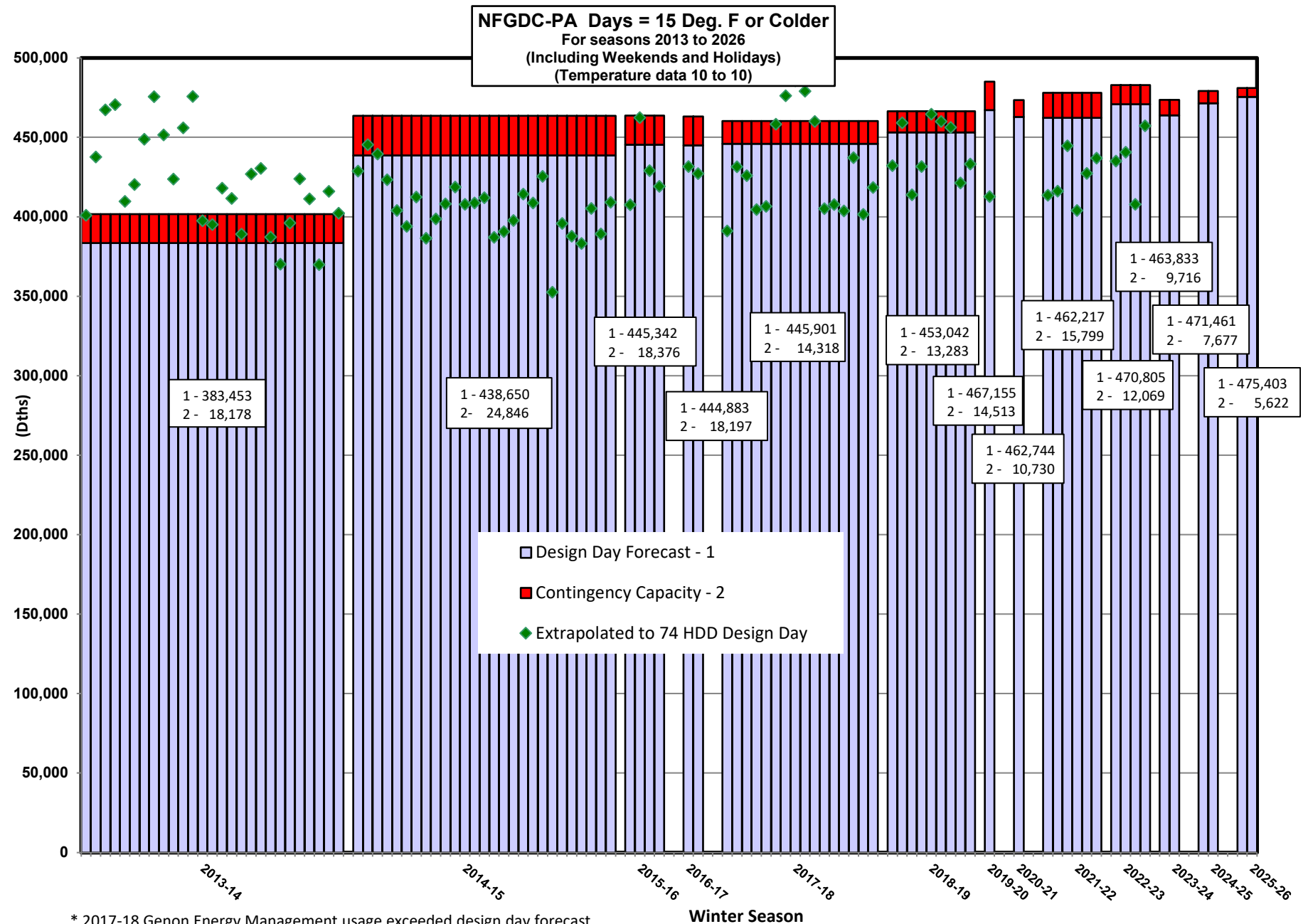
¹ The storage over/(under) interest rate was calculated on a stand-alone basis using the TME July as the determination period.

PA Adjusted Capacity Mix - 11/01/2023

Based on Primary Receipt Points



Southwest
14%



National Fuel Gas Distribution Corporation-PA ("Distribution")
Forecast Design Day Requirements and Contingency Capacity Summary (Dth/day)

Table 1

Winter Season	Total Intermediate Capacity	Total Forecast Requirements	Year Over Year % Change	Contingency Capacity	Contingency Capacity %
2018-2019	340,885	327,603		13,282	4.1%
2019-2020	340,690	326,177	-0.4%	14,513	4.4%
2020-2021	340,811	330,081	1.2%	10,730	3.3%
2021-2022	350,705	334,926	1.5%	15,779	4.7%
2022-2023	350,774	338,705	1.1%	12,069	3.6%
2023-2024	350,876	341,160	0.7%	9,716	2.8%
2024-2025	350,876	343,199	0.6%	7,677	2.2%
2025-2026	350,876	345,214	0.6%	5,662	1.6%
2026-2027	350,876	347,002	0.5%	3,874	1.1%
2027-2028	350,876	349,039	0.6%	1,837	0.5%

Table 2

Winter Season	Total Intermediate Capacity	Total Forecast Requirements	Year Over Year % Change	Contingency Capacity	Proposed Intermediate Capacity	Updated Contingency	Contingency Capacity %
2018-2019	340,885	327,603		13,282			4.1%
2019-2020	340,690	326,177	-0.4%	14,513			4.4%
2020-2021	340,811	330,081	1.2%	10,730			3.3%
2021-2022	350,705	334,926	1.5%	15,779			4.7%
2022-2023	350,774	338,705	1.1%	12,069			3.6%
2023-2024	350,876	341,160	0.7%	9,716			2.8%
2024-2025	355,876	343,199	0.6%	7,677	5,000	12,677	3.7%
2025-2026	355,876	345,214	0.6%	5,662	5,000	10,662	3.1%
2026-2027	355,876	347,002	0.5%	3,874	5,000	8,874	2.6%
2027-2028	355,876	349,039	0.6%	1,837	5,000	6,837	2.0%

Pipeline Penalty and Rate Case Settlement Credits Received		
Invoice Date	Pipeline	Refund Amount
12/12/2023	Columbia Gas Transmission, LLC	\$ (4,405.65)
12/12/2023	Columbia Gas Transmission, LLC	\$ (27,629.37)
4/10/2023	Texas Eastern Transmission, LP	\$ (646.82)
5/10/2023	Texas Eastern Transmission, LP	\$ (6,904.63)
10/10/2023	Texas Eastern Transmission, LP	\$ (812.81)
11/10/2023	Texas Eastern Transmission, LP	\$ (158.14)



COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
COMMONWEALTH KEYSTONE BUILDING
400 NORTH STREET, HARRISBURG, PA 17120

BUREAU OF
INVESTIGATION
&
ENFORCEMENT

March 8, 2024

Via Electronic Mail

Administrative Law Judge Charece Z. Collins
Pennsylvania Public Utility Commission
Office of Administrative Law Judge
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
charcollin@pa.gov

Re: Pennsylvania Public Utility Commission v.
National Fuel Gas Distribution Corporation
Docket No. R-2024-3045177
I&E Direct Testimony

Your Honor:

Enclosed please find the following prepared Direct Testimony of the Bureau of Investigation and Enforcement's witness in the above-captioned proceeding:

I&E Statement No. 1 – Sakaya

Copies are being served on parties of record per the attached Certificate of Service. Should you have any questions, please do not hesitate to contact me.

Sincerely,

A handwritten signature in black ink that reads "Carrie B. Wright". The signature is written in a cursive, flowing style.

Carrie B. Wright
Prosecutor
Bureau of Investigation and Enforcement
PA Attorney ID No. 208185
(717) 783-6156
carwright@pa.gov

CBW/ac
Enclosures

cc: Secretary Rosemary Chiavetta (*Cover Letter and Certificate of Service only – via e-file*)
Per Certificate of Service

I&E Statement No. 1
Witness: Esyan A. Sakaya

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Docket No. R-2024-3045177

Direct Testimony

of

Esyan A. Sakaya

Bureau of Investigation and Enforcement

Concerning:

Renewable Natural Gas Purchase Proposal Update

Certified Natural Gas Pilot Program

TABLE OF CONTENTS

INTRODUCTION	1
RENEWABLE NATURAL GAS PROGRAM PROPOSAL UPDATE	2
CERTIFIED NATURAL GAS PILOT PROGRAM.....	3

1 **INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A. My name is Eryan A. Sakaya. My business address is Pennsylvania Public Utility
4 Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg,
5 PA 17120.

6
7 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

8 A. I am employed as a Fixed Utility Valuation Engineer in the Pennsylvania Public
9 Utility Commission's ("Commission") Bureau of Investigation and Enforcement
10 ("I&E").

11
12 **Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL**
13 **BACKGROUND.**

14 A. My education and professional background are set forth in the attached
15 Appendix A.

16
17 **Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE AND OTHER**
18 **PROCEEDINGS.**

19 A. I&E is responsible for protecting the public interest in proceedings before the
20 Commission. The I&E analysis in this proceeding is based on its responsibility to
21 represent the public interest. This responsibility requires the balancing of the
22 interests of the ratepayers, the utility, and the regulated community as a whole.

1 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

2 A. The purpose of my direct testimony is to address National Fuel Gas Distribution
3 Corporation's ("NFG" or "Company") proposals to purchase renewable natural
4 gas ("RNG") and a pilot certified natural gas ("CNG") program.
5

6 **Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?**

7 A. No.
8

9 **RENEWABLE NATURAL GAS PROGRAM PROPOSAL UPDATE**

10 **Q. WHAT IS RENEWABLE NATURAL GAS?**

11 A. RNG is biogas captured from freely emitting methane sources such as agricultural
12 and food waste streams, landfill gasses, and wastewater treatment processes.
13

14 **Q. HAS NFG PROPOSED THE PURCHASE OF RNG IN THE PAST?**

15 A. Yes. NFG proposed the purchase of RNG in its last two purchased gas cost filings
16 at Docket Nos. R-2022-3030235 and R-2023-3037428.
17

18 **Q. HAS NFG ENTERED INTO AGREEMENTS TO PURCHASE RNG SINCE**
19 **THOSE PRIOR FILINGS?**

20 A. No.

1 **Q. WHY HASN'T NFG ENTERED INTO AGREEMENTS TO PURCHASE**
2 **RNG?**

3 A. Company witness Christopher A. Cej states that NFG has yet to find a partner that
4 could provide RNG to NFG's firm pipeline capacity assets at a price similar in
5 price to natural gas that would be beneficial to ratepayers (NFG St. No. 1, pp. 4-5).

6
7 **Q. DESPITE THE AFOREMENTIONED ONGOING ISSUES WITH RNG**
8 **PROCUREMENT, IS NFG STILL CONSIDERING THE PURCHASE OF**
9 **RNG?**

10 A. Yes. In addition to the previously mentioned concerns, NFG wants to be able to
11 purchase RNG without paying a premium to acquire the environmental attributes
12 associated with RNG (NFG St. No. 1, pp. 4-5).

13
14 **Q. SINCE NFG HAS YET TO RESOLVE ITS RNG PROCUREMENT ISSUES,**
15 **WHAT IS THE COMPANY PROPOSING IN THIS FILING?**

16 A. The Company is proposing a pilot program to procure CNG (NFG St. No. 2, p. 8).

17
18 **CERTIFIED NATURAL GAS PILOT PROGRAM**

19 **Q. WHAT IS CNG?**

20 A. CNG is natural gas that has been evaluated and verified by an independent third-
21 party to have been produced with reduced greenhouse gas emissions and
22 environmental impacts, beyond current environmental regulations.

1 **Q. WHY HAS NFG CONSIDERED PURCHASING CNG?**

2 A. The Company is looking to procure gas at the least cost from additional sources
3 and states an increasing percentage of its traditional gas supply purchases from
4 suppliers located within the Appalachian production basin aggregation pools are
5 sourced from CNG certified production wells (NFG St. No. 1, p. 5).

6
7 **Q. WILL NFG CONSIDER THESE SUPPLIES FOR PURCHASING CNG IN**
8 **THE FUTURE?**

9 A. Yes. The Company is interested in pursuing further negotiations with these
10 potential suppliers to develop a CNG purchase arrangement, and as a result, has
11 proposed a CNG pilot program in this proceeding (NFG St. No. 2, pp. 10-12).

12
13 **Q. BRIEFLY EXPLAIN THE COMPANY'S PROPOSED CNG PILOT**
14 **PROGRAM.**

15 A. The Company is proposing to implement a three-year pilot program designed to
16 purchase CNG. The pilot program will limit the incremental cost associated with
17 CNG premiums to \$175,000 per year. NFG estimates the premium involved in
18 procuring CNG costs between \$0.03 - \$0.07 per dekatherm. The Company
19 anticipates buying CNG at existing trading points located at either Texas Eastern's
20 M-2 Pool, or Tennessee's Gas Pipelines Zone-4 200 leg pool. The Company
21 intends to mitigate cost risk under its Gas Cost Management Plan and would seek
22 least cost procurement through an RFP process. The Company forecasts

1 implementing such a plan during the summer injection system for a period of three
2 years (NFG St. No. 2, pp. 10 - 12). The Company agrees to limit purchases of
3 CNG to those certified and that have obtained one of the following standards:

- 4 1. MiQ; or
 - 5 2. Oil and Gas Methane Partnership (“OGMP”) 2.0.
- 6

7 **Q. DESCRIBE THE MIQ STANDARD.**

8 A. The MiQ Standard was created to establish a practical measure for assessing
9 methane emissions management. To carry out certification, upstream onshore and
10 offshore facilities must perform under three criteria: (1) methane intensity below a
11 certain threshold; (2) company practices that promote a culture of emissions
12 management; and (3) comprehensive monitoring technology deployment to detect
13 fugitive emissions (NFG St. No. 2, p. 10).

14

15 **Q. DESCRIBE THE OGMP STANDARD.**

16 A. The OGMP was created by the Climate and Clean Air Coalition as a voluntary
17 initiative to help companies reduce methane emissions within oil and gas
18 operations. The most recent form of the initiative, OGMP 2.0, includes five
19 reporting levels, with the highest level requiring that emissions tracking and
20 reports include site and source-level measurements. Companies have three years
21 to achieve compliance for operated assets and five years for non-operated assets
22 (NFG St. No. 2, p. 11).

1 **Q. DO HAVE ANY CONCERNS ABOUT THE GAS CERTIFICATION**
2 **STANDARDS BEING PROPOSED BY NFG?**

3 A. Yes.
4

5 **Q. PLEASE EXPLAIN YOUR CONCERNS.**

6 A. I have three concerns. First, there are too many certification standards for this gas
7 product. Based upon my research, I cannot determine which standard is better in
8 determining the level of methane emissions. Second, I do not know the names of
9 the potential independent third-party certifiers and if there are any potential
10 conflicts of interest with NFG. Lastly, Company testimony did not detail how the
11 program would be subject to reporting requirements during the pilot run to gauge
12 progress.
13

14 **Q. HAS THE COMPANY ADDRESSED WHETHER THE PURCHASE OF**
15 **CNG WILL RESULT IN HIGHER GAS COST?**

16 A. No. While the budgeted \$175,000 per year for the proposed pilot may be
17 reasonable, it is still critical that NFG works on protecting its ratepayers. Low
18 emission differentiated gas (RNG or CNG) is more expensive than conventional
19 natural gas. The present low price of conventional natural gas does not account
20 for any costs associated with the environmental and public health impact linked to
21 methane emissions in conventional natural gas. Therefore, ratepayers should be

1 protected from any future changes of NFG's current supply mix to differentiated
2 gas that could impact customer pricing. If NFG were mandated by any future
3 federal or state environmental legislation to increase its annual inventory of this
4 product, it may force NFG to reduce the purchase of conventional natural gas and
5 increase the purchase of certified natural gas. Because of this possibility, the
6 Commission may need to update procurement strategies and reporting
7 requirements to best comply with increased usage of differentiated gas and control
8 the cost impact to natural gas customers.

9
10 **Q. IS THE POTENTIAL PURCHASE OF HIGHER COST GAS A**
11 **CONCERN?**

12 A. Yes. The potential purchase of higher cost CNG is a concern as it may be
13 inconsistent with the Company's obligation to pursue a least cost fuel procurement
14 strategy.

15
16 **Q. PLEASE EXPLAIN THE LEAST COST FUEL PROCUREMENT**
17 **REQUIREMENT.**

18 A. Sections 1317 and 1318 of the Public Utility Code require utilities to pursue a least
19 cost fuel procurement policy consistent with their obligation to provide safe,
20 adequate, and reliable service to its customers. Among other things, this
21 obligation requires that the utility take all prudent steps necessary to secure

1 favorable gas supply contracts and to obtain lower cost gas supplies on both short-
2 term and long-term bases.

3
4 **Q. WHAT DO YOU RECOMMEND CONCERNING THE CNG PILOT?**

5 A. I recommend that the proposed CNG pilot program be denied as it is not clear that
6 the pilot adheres to the Company's least cost procurement obligation, and there are
7 concerns about the validity of third-party certifications specific to methane
8 emission mitigation.

9
10 **Q. PLEASE EXPLAIN YOUR CONCERNS THAT THE CNG PILOT**
11 **PROGRAM DOES NOT ADHERE TO LEAST COST PROCUREMENT.**

12 A. The pilot program, as presented in the filing, lacks specific commitments and
13 details necessary to ensure the Company is pursuing a least cost procurement
14 policy. As discussed above, one of the findings to determine least cost
15 procurement is whether the utility has negotiated favorable gas supply contracts.
16 Here, there is no way to make such a determination because there are no actual
17 contracts or descriptions of contract terms for the parties to review. The Company
18 laid out its plan to issue an RFP and stated that it believes such plans will ensure
19 least cost procurement (NFG St. No. 2, p. 12). Nonetheless, the cost of CNG will
20 be at a premium in comparison to the cost of conventional natural gas. In an
21 attempt to predict prices, NFG did provide a forward curve gas price forecast on
22 PGC Exhibit Number 25, pp. 2-5. NFG's forecast estimated the prices of

1 conventional natural gas from November 2023 to December 2025; however, these
2 forecasts cannot factor the price volatility or unexpected events that could
3 negatively affect natural gas prices during that span of time. Based on these facts,
4 NFG cannot reliably estimate the premium difference in procuring CNG versus
5 conventional natural gas. In short, NFG provided no forecast of CNG prices
6 which makes it impossible to determine whether the proposed pilot will satisfy the
7 least cost procurement requirement.

8
9 **Q. PLEASE EXPLAIN YOUR CONCERNS REGARDING THIRD-PARTY**
10 **CERTIFICATIONS.**

11 A. I have three concerns about third-party certifications. First, there is no single
12 standard, the two standards being proposed by NFG are two of many different
13 methane certification standards, it is difficult to determine which standard is more
14 accurate. Next, because there is no industry-wide standard for third-party
15 certification, no state or federal regulatory body currently monitors these third-
16 party certification programs, which prevents transparency. Lastly, without a
17 regulatory body to monitor CNG transactions, there is no way to verify if there are
18 any conflicts of interest between the certifying agency and the natural gas
19 distribution company.

20
21 **Q. WHY IS IT IMPORTANT TO REDUCE METHANE EMISSIONS?**

22 A. According to the PA Department of Environmental Protection, methane is the

1 primary component of natural gas, and has been identified by the U.S.
2 Environmental Protection Agency as the second-most prevalent greenhouse gas
3 emitted in the United States from human activities. Federal estimates that the
4 natural gas and oil industries account for a quarter of U.S. methane emissions.
5 Therefore, reducing methane leaks from the oil and gas sector is one of the
6 essential steps needed to reduce global greenhouse gas emissions and reduce the
7 impacts of climate change.¹
8

9 **Q. IF THE COMMISSION DOES APPROVE THE COMPANY’S CNG PILOT**
10 **PROGRAM, WHAT DO YOU RECOMMEND?**

11 A. If the Commission approves the Company’s proposed CNG pilot program, I have
12 two recommendations. First, the Company be required to show how the purchase
13 of CNG complies with least cost procurement for all gas, not just CNG. The CNG
14 purchase price should be comparable to the cost of traditional gas purchases.
15 Lastly, Company should be required to provide a report in future 1307(f) filings
16 describing the details of the program for the duration of the pilot.
17

18 **Q. WHAT DETAILS SHOULD THESE REPORTS INCLUDE?**

19 A. These reports should include an overall assessment of the program, evaluation of

¹ “State.” Reducing Volatile Organic Compounds and Methane in Pennsylvania, 2022, [files.dep.state.pa.us/PublicParticipation/PublicParticipationCenter/PubPartCenterPortalFiles/Environmental Quality Board/2022/October 12, 2022/03_7-579_COG VOC_FinalOmit/01_7-579_COG VOC_FinalOmit_Exec Sum.pdf](https://files.dep.state.pa.us/PublicParticipation/PublicParticipationCenter/PubPartCenterPortalFiles/EnvironmentalQualityBoard/2022/October12,2022/03_7-579_COG_VOC_FinalOmit/01_7-579_COG_VOC_FinalOmit_ExecSum.pdf), Accessed February 28, 2024.

1 the program to see if it should be continued, ended, or expanded, the dates and
2 terms of the CNG contracts, the methane mitigation percentages per transaction,
3 the volumes purchased, price paid, the premium over the cost of traditional natural
4 gas, the revenues credited to ratepayers and the amount shared with the Company,
5 and how each of these amounts were determined.

6 NFG should also be required to report on the daily quantities of CNG
7 purchased; identify the PGC rate impact of its CNG purchases; identify the BTU
8 content of its CNG purchases to the extent such data is available; and report on the
9 sales activity, including volumes sold and prices obtained, on a monthly basis.

10
11 **Q. WHY DO YOU RECOMMEND THAT THE COMPANY BE REQUIRED**
12 **TO REPORT THESE DETAILS?**

13 A. The CNG pilot program could result in higher gas costs. By providing these
14 details, the Commission and interested parties can evaluate the CNG pilot program
15 and determine if the program is consistent with least cost procurement and truly
16 mitigates methane emissions, which will enable the Commission to determine if
17 the CNG program should continue, be modified, or terminated.

18
19 **Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS CONCERNING**
20 **THE PROPOSED CNG PILOT PROGRAM?**

21 A. Yes. Based on the filing, the Company intends to have an effective purchased gas
22 tariff on August 1, 2024. Therefore, if the pilot program is supposed to last three

1 years, I recommend this program should end on July 31, 2027. At that point, the
2 program should be evaluated via the recommended reporting requirements
3 explained here, and a determination of whether to continue, modify, or end the
4 program, as a pilot or otherwise, should be made.

5
6 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

7 **A. Yes.**

Esyau A. Sakaya

**THE PENNSYLVANIA PUBLIC UTILITY COMMISSION
400 North Street
HARRISBURG, PA 17120**

Education:

National Association of Regulatory Utility Commissioners, Clearwater, FL
Utility Rate School; Utility Rate Making Basics, October 2019

Society of Depreciation Professionals, Philadelphia, PA
Introduction to Depreciation; Depreciation Fundamentals, September 2019

Temple University, Philadelphia, PA
Bachelor of Science; Major in Engineering Technology, 2015

Community College of Philadelphia, Philadelphia, PA
Associate of Applied Science; Major in Construction Management Technology, 2011

Island School of Building Arts, Gabriola Island, BC-Canada
Certificate Graduate: Heavy Timber Construction August 2002-November 2002

Solar Energy International, Carbondale, CO
Certificate Graduate: Basic and Advanced Photovoltaic Design, April 2002-May 2002

Experience:

12/2018-Present

Pennsylvania Public Utility Commission-Harrisburg, PA

Fixed Utility Valuation Engineer - Assist in engineering related studies related to valuation, depreciation, cost of service, quality of service as they apply to regulated utilities. Contribute in evaluating, contrasting and conducting performance analyses in distinctive sections of valuation engineering and rate structure involving valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design. Provide expert testimony in rate related utility cases.

4/2018-12/2018

Pennsylvania Department of Transportation-Harrisburg, PA

Photogrammetry Technician I - Created three-dimensional mapping layouts of natural and man-made features from stereoscopic images on a computer workstation. Assisted in the field placement of ground based surveyed control-points prior to aerial photography acquisition. Provided field support in the use of laser scans for comprehensive digital surveying data. Operated global positioning satellite surveying equipment to obtain accurate geodetic coordinates of pre-established benchmarks.

8/2017-4/2018

Pennoni and Associates. Consulting Engineers-King of Prussia, PA

Construction Inspector – Provided quality assurance in the onsite material testing of concrete, soils, and asphalt. Read and interpreted construction drawings and specifications of materials and components. Completed daily reports regarding project progress to engineers, project managers/superintendents, contractors, and clients.

TESTIMONY SUBMITTED:

I have assisted and/or submitted testimony in the following proceedings:

<u>NO.</u>	<u>Case</u>
1.	UGI Gas Utilities - Gas Division, Docket No. R-2018-3006814
2.	Newtown Artesian Water Company, Docket No. R-2018-3006904
3.	Pittsburgh Wastewater, Docket No. M-2018-2640803
4.	PAWC Purchase of Steelton, Docket No. A-2019-3006814
5.	Philadelphia Gas Works, Docket Nos. R-2019-3009016 & R-2019-3007636
6.	Community Utilities Water, Docket No. R-2019-3008947
7.	Aqua Purchase of Cheltenham, Docket No. A-2019-3008491
8.	UGI North, Docket No. R-2019-3009647
9.	UGI Central, Docket No. R-2019-3009647
10.	UGI South, Docket No. R-2019-3009647
11.	Twin Lakes Utilities, Docket No. R-2019-3010958
12.	Penn Power Company, Docket No. P-2019-3012628
13.	UGI Gas Utilities, Docket No. R-2019-3015162
14.	National Fuel and Gas Distribution, Docket No. R-2020-3015251
15.	Columbia Gas of PA, Docket Nos. R-2020-3018993 & R-2020-3018835
16.	Duquesne Light Company, Docket No. P-2020-3019522

17. PA American Water Co., Docket Nos. R-2020-3019369 & R-2020-3010937
18. Bethlehem Water Company, Docket No. R-2020-3020256
19. Audubon Water Company, Docket No. R-2020-3020919
20. Twin Lakes Utilities, Docket No. P-2020-3020914
21. Pike County Light and Power-Gas, Docket No. R-2020-3022134
22. Pike County Light and Power-Electric, Docket No. R-2020-3022135
23. Duquesne Light Company, Docket No. R-2021-3024750
24. Community Utilities Water, Docket No. R-2021-3025206
25. Community Utilities Wastewater, Docket No. R-2021-3025206
26. Hanover Municipal Water Works, Docket No. R-2021-3026116
27. Aqua Pennsylvania, Inc., Docket Nos. R-2021-3027385 & R-2021-3027386
28. Aqua Purchase of Willistown, Docket No. A-2021-3027268
29. National Fuel and Gas Distribution, Docket No. R-2022-3030235
30. UGI Gas Utilities, Docket No. R-2021-3030218
31. PECO Energy Company – Gas, Docket No. R-2022-3031113
32. Valley Energy, Inc., Gas, Docket No. R-2022-3032300
33. Citizens’ Electric Company, Docket No. R-2022-3032369
34. Leatherstocking Gas Company, LLC Docket No. R-2022-303276
35. National Fuel and Gas Distribution, Docket No. R-2022-3035730
36. Aqua Purchase of Shenandoah, Docket No. A-2022-3034143
37. UGI Electric Utilities, Docket No. R-2022-3037368
38. Philadelphia Gas Works, Docket No. R-2023-3037933
39. Columbia Water, Docket No. R-2023-3040258
40. Community Utilities Water, Docket No. R-2023-3042804
41. Community Utilities Wastewater, Docket No. R-2023-3042805
42. CAN DO Water, Docket No. R-2023-3040153

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3045177
	:	
National Fuel Gas Distribution Corporation	:	

CERTIFICATE OF SERVICE

I hereby certify that I am serving the foregoing **Direct Testimony** dated March 8, 2024, in the manner and upon the persons listed below:

Served via Electronic Mail Only

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Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
Harrisburg, PA 17105-3265
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC	:	
UTILITY COMMISSION	:	
	:	
v.	:	DOCKET NO. R-2024-3045177
	:	
NATIONAL FUEL GAS	:	
DISTRIBUTION CORPORATION	:	

DIRECT TESTIMONY
OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MARCH 8, 2024

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DIRECT TESTIMONY OF JEROME D. MIERZWA

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal with and Vice President of Exeter Associates, Inc. (“Exeter”). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Canisius College in Buffalo, New York, in 1981 with a Bachelor of Science Degree in Marketing.¹ In 1985, I received a Master’s Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation (“NFGD”) as a Management Trainee in the Research and Statistical Services Department (“RSS”). I was promoted to Supervisor RSS in January 1987. While employed with NFGD, I conducted various financial and statistical analyses related to the Company’s market research activity and state regulatory affairs. In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation’s (“NFG Supply”) rate department where my responsibilities included utility cost of service and rate design analysis, expense and revenue requirement forecasting, and activities related to federal regulation. I was also responsible for preparing NFG Supply’s Federal Energy Regulatory Commission (“FERC”) Purchased Gas Adjustment (“PGA”) filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFGD’s 1307(f) proceedings.

¹ Effective August 1, 2023, Canisius College became Canisius University.

1 In April 1990, I accepted a position as a Utility Analyst with Exeter. In December
2 1992, I was promoted to Senior Regulatory Analyst. Effective April 1, 1996, I became a
3 Principal of Exeter. Since joining Exeter, I have specialized in evaluating the gas
4 purchasing practices and policies of natural gas distribution companies (“NGDCs”), utility
5 class cost of service and rate design analysis, sales and rate forecasting, performance-based
6 incentive regulation, revenue requirement analysis, the unbundling of utility services, and
7 the evaluation of customer choice natural gas transportation programs.

8 Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS
9 ON UTILITY RATES?

10 A. Yes. I have provided testimony on more than 450 occasions in proceedings before FERC,
11 and state utility regulatory commissions in Arkansas, Connecticut, Delaware, Georgia,
12 Illinois, Indiana, Louisiana, Maine, Massachusetts, Montana, Nevada, New Jersey, Ohio,
13 Rhode Island, South Carolina, Texas, Utah, and Virginia, as well as before the
14 Pennsylvania Public Utility Commission (“PaPUC” or “Commission”).

15 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

16 A. Exeter Associates, Inc. was retained by the Pennsylvania Office of Consumer Advocate
17 (“OCA”) to review the 2024 annual 1307(f) Purchased Gas Cost (“PGC”) rate filing of
18 National Fuel Gas Distribution Corporation (“NFGD” or “the Company”). My testimony
19 presents the results of my review. I have assisted the OCA in the review of NFGD’s annual
20 PGC filings each year since 1991, with the exception of the Company’s 1995 filing.

21 Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

22 A. My findings and recommendations are as follows:

- 23 • Accurate forecasting of customer design day requirements is essential
24 to ensuring the provision of reliable natural gas service is on a least-cost
25 basis. This is because an NGDC like NFGD utilizes its design day
26 requirements forecast to determine the amount of interstate pipeline
27 capacity it acquires and maintains. The design day forecasting model

utilized by NFGD is a concern as it appears to be over estimating the Company's design day requirements. I recommend that the Company further analyze its design day forecasting model and address this concern in its 2025 PGC proceeding. Until this concern is resolved, I further recommend that the Company not acquire the additional NFG Supply capacity for the winter of 2024-2025 as it has proposed in this proceeding;

- The purchased gas cost audit conducted by the Bureau of Audits in Docket No. D-2022-3031418 found that NFGD should refund \$111,398 to PGC customers. This refund was attributable to errors in the reporting of prior period adjustments and the amortization of over/under collection balances during the December 2017 – November 2020 audit period. NFGD should refund this amount to PGC customers in its May 2024 quarterly PGC filing. The audit also recommended that NFGD implement controls to prevent, detect, and correct such errors. NFGD should immediately begin evaluating and implementing such controls, and identify and report the controls it has implemented in next year's annual PGC filing; and
- NFGD's proposal to adopt a Certified Natural Gas ("CNG") pilot program should be approved.

Q. DID YOUR REVIEW OF NFGD'S FILING IDENTIFY ANY ERRORS IN THE COMPANY'S FILING?

A. Yes. My review found that in calculating interest on storage injections and withdrawals on Exhibit NJH-1, page 4, the Company used the incorrect interest rates.

Q. HAS THE COMPANY AGREED TO REVISED NJH-1, PAGE 4, TO REFLECT THE CORRECT INTEREST RATES?

A. Yes. In the response to OCA-2-6 the Company agreed to revised Exhibit NJH-1, page 4, to reflect the correct interest rates. Based on the response to OCA-2-6, this correction would increase the interest rate credit to PGC customers from \$23,740 to \$51,132, or by \$27,392.

II. BACKGROUND

Q. HOW OFTEN DOES NFGD REVISE OR UPDATE ITS PGC RATE?

Q. PLEASE DESCRIBE THE TIME PERIODS RELEVANT TO YOUR INVESTIGATION IN THIS PROCEEDING.

In its annual PGC rate proceedings, NFGD’s actual gas procurement activity during the historic annual review period is examined for consistency with least-cost gas procurement standards. The historic review period extends from the December two years

1 prior to the annual PGC filing date through November of the year prior to the annual filing.
2 For this proceeding, the historic review period is December 2022 through November 2023.

3 Q. BRIEFLY DESCRIBE NFGD'S CURRENT GAS SUPPLY AND INTERSTATE
4 PIPELINE TRANSPORTATION ARRANGEMENTS.

5 A. Gas supplies are delivered almost exclusively to NFGD under the various firm
6 transportation arrangements the Company maintains with its interstate pipeline affiliate,
7 NFG Supply. NFGD purchases small quantities of gas which are delivered directly to its
8 system (local production). NFG Supply's facilities are located in the western portions of
9 Pennsylvania and New York. Significant quantities of Marcellus Shale production region
10 gas supplies are purchased by NFGD which are delivered directly to NFG Supply and then,
11 subsequently redelivered to NFGD.² Marcellus Shale gas supplies are also purchased and
12 delivered to NFG Supply by upstream interstate pipelines from Marcellus Shale production
13 regions that NFG Supply's transmission facilities do not access. Gas supplies may also be
14 purchased and delivered to NFG Supply by upstream pipelines from other producing
15 regions such as the Gulf Coast region of the United States. The primary upstream interstate
16 pipeline delivering gas to NFG Supply on NFGD's behalf is Tennessee Gas Pipeline
17 ("Tennessee"). Other upstream interstate pipelines that deliver gas to NFG Supply on
18 NFGD's behalf are Texas Eastern Gas Transmission ("Texas Eastern") and Columbia Gas
19 Transmission ("Columbia"). NFGD's current capacity resources are summarized in greater
20 detail in PGC Exhibit No. 4-A.

21 Gas delivered to NFG Supply on NFGD's behalf may be delivered to NFGD on a
22 current basis or injected into NFG Supply's storage facilities and redelivered at a later time.

² The Marcellus Shale production region extends across western Pennsylvania, West Virginia, and southeast Ohio, and is the largest source of natural gas in the United States.

1 NFGD purchases storage service from NFG Supply under two rate schedules.³ NFGD also
2 purchases a relatively small quantity of storage service from Columbia.

3 Q. PLEASE IDENTIFY THE VARIOUS SERVICES PROVIDED BY NFGD AND
4 THE CUSTOMERS IT SERVES.

5 A. NFGD provides retail sales service and several different transportation services. The
6 transportation services provided by NFGD are Small Aggregation Transportation
7 Customer (“SATC”) service, MMT service, and Daily Metered Transportation (“DMT”)
8 service. Customers subscribing to SATC service are commonly referred to as a “Choice”
9 customers and are predominantly Residential and Small Commercial customers. MMT and
10 DMT customers are predominantly larger Commercial and Industrial customers. SATC
11 and MMT service customer usage is measured on a monthly basis while DMT customer
12 usage is measured on a daily basis.

13
14 **III. DESIGN DAY FORECASTING MODEL**

15 Q. HOW DOES A NGDC LIKE NFGD TYPICALLY DETERMINE THE
16 AMOUNT OF INTERSTATE PIPELINE CAPACITY THAT IT SHOULD
17 RESERVE OR MAINTAIN?

18 A. An NGDC would typically reserve interstate pipeline capacity sufficient to meet the design
19 day demands of its firm retail sales customers that cannot be met with on-system capacity
20 resources such as storage or local production. Design day is an extremely cold day that an
21 NGDC selects and utilizes for capacity planning purposes. The design day utilized by
22 NFGD for capacity planning purposes is a day with an average temperature of -9°F, or 74
23 heating degree days (“HDDs”).

³ NFGD purchases storage service from NFG Supply under the Enhanced Storage Service (“ESS”) and Firm Storage Service (“FSS”) rate schedules.

1 It is also common for an NGDC to reserve pipeline capacity to meet the design day
2 demands of their firm transportation customers, or the balancing requirements of their firm
3 transportation customers. If pipeline capacity is reserved to serve firm transportation
4 customers, mechanisms are typically in place to recover the costs associated with this
5 capacity from firm transportation customers. NFGD maintains interstate pipeline capacity
6 resources sufficient to meet the demands of its sales and SATC customers and the
7 balancing requirements of its MMT customers. NFGD recovers the costs associated with
8 the capacity reserved to serve sales customers through PGC rates and a gas cost
9 Distribution Charge.⁴ The costs associated with the capacity reserved to serve SATC
10 service customers is recovered through the assignment of capacity to suppliers serving
11 SATC service customers and the gas cost Distribution Charge. NFGD recovers the costs
12 associated with providing balancing service to its MMT customers through balancing
13 charges that are assessed to these customers.

14 Q. PLEASE DESCRIBE THE FORECASTING MODEL DEVELOPED BY NFGD
15 TO PROJECT THE DESIGN DAY REQUIREMENTS OF ITS CUSTOMERS
16 FOR WHICH IT RESERVES INTERSTATE PIPELINE CAPACITY.

17 A. NFGD's design day forecasting model is presented and explained in PGC Exhibit No. 15.
18 NFGD separately determines the projected design day demands of its smaller, generally
19 weather-sensitive, sales and transportation customers whose usage is metered on a monthly
20 basis, and its larger non-weather sensitive transportation customers whose usage is metered
21 either on a monthly or on a daily basis. For weather-sensitive customers, NFGD utilizes a
22 method of extracting a baseload volume and computing a heating volume to determine
23 usage at design day (74 HDD) temperatures. This analysis is based on monthly usage. In
24 this year's proceeding, NFGD utilized weather-sensitive customer usage dating back to

⁴ Please see PGC Exhibit No. 8, page 5, line 6 through line 17, and PGC Exhibit No. 13A for a detailed description of the gas cost Distribution Charge and an explanation as to how it is calculated.

2009 to develop the forecasted usage of weather-sensitive customers. For non-weather-sensitive customers, NFGD utilized customer operating schedules as explained in greater detail in PGC Exhibit No. 15.

Q. FOR THOSE CUSTOMERS WHICH NFGD SECURES AND MAINTAINS INTERSTATE PIPELINE CAPACITY, DOES THE COMPANY STRICTLY RELY ON THE RESULTS OF ITS DESIGN DAY FORECAST TO DETERMINE THE AMOUNT OF CAPACITY TO RESERVE TO SERVE THOSE CUSTOMERS?

A. No. As explained on page 9 through 11 of the direct testimony of Lisa A. Petko, in addition to maintaining the capacity indicated by the Company's design day forecast, NFGD maintains additional capacity referred to as "contingency capacity." This contingency capacity has historically been maintained to ensure reliability in the event that NFGD's system experiences load requirements that exceed projected design day requirements.

Q. WHY WOULD NFGD EXPERIENCE LOAD REQUIREMENTS THAT EXCEED PROJECTED DESIGN DAY REQUIREMENTS AND IS THERE EVIDENCE THAT LOADS HAVE HISTORICALLY EXCEEDED FORECASTED DESIGN DAY REQUIREMENTS?

A. NFGD's design day forecasting model utilizes monthly usage to project the demands of weather-sensitive customers. This tends to underestimate actual demands under colder temperatures because the usage per HDD of weather-sensitive customers tends to increase as HDDs increase. Evidence of this is presented in Exhibit LAP-3, which provides a comparison of the Company's forecasted design day demands and the expected usage of its customers under design day conditions based on actual usage on days which the average temperature was 15°F (50 HDD) or colder. That is, based on weather-sensitive usage on each day, NFGD extrapolated what design day usage would have been at -9°F (74 HDD).

As shown on Exhibit LAP-3, on numerous occasions from the winter of 2013-2014 through the winter of 2018-2019, extrapolated design day usage has exceeded forecasted design day usage inclusive of contingency capacity.

Q. WHAT IS YOUR CONCERN WITH THE COMPANY'S DESIGN DAY FORECASTING MODEL?

A. Accurate forecasting of customer design day requirements is essential to ensuring the provision of reliable service on a least-cost basis. This is because an NGDC like NFGD utilizes its design day forecast to determine the amount of interstate pipeline capacity it acquires and maintains. My concern with NFGD's design day forecasting model is that for the most recent three winter seasons, the model has significantly over-estimated expected customer requirements under design day weather conditions.

Exhibit LAP-3 of the Company's filing identifies expected design day demands on days in which the average temperature was 15°F or colder, extrapolated to reflect expected demands at design day temperatures. As shown on Exhibit LAP-3, for the last three winter seasons, extrapolated demands were significantly less than forecasted design day demands exclusive of contingency capacity, and contingency capacity would not have been required to meet customer requirements as would have been required in prior winter seasons. Table 1 identifies the values reflected in Exhibit LAP-3 for the last three winter seasons.

Table 1. Extrapolated Versus Forecasted Design Day Demands (Dth)			
Date	Extrapolated	Forecasted	Difference
February 15, 2022	397,680	462,217	(64,537)
January 21, 2022	400,170	462,217	(62,047)
January 26, 2022	427,564	462,217	(34,653)
January 29, 2022	388,359	462,217	(73,858)
January 30, 2022	410,914	462,217	(51,303)
February 14, 2022	420,022	462,217	(42,195)
December 23, 2022	414,678	470,805	(56,127)

December 24, 2022	419,969	470,805	(50,836)
December 25, 2022	388,718	470,805	(82,087)
February 3, 2023	435,496	470,805	(35,309)
January 14, 2024	388,918	463,833	(74,915)
January 15, 2024	392,519	463,833	(71,314)
January 16, 2024	423,164	463,833	(40,669)
January 17, 2024	420,198	463,833	(43,635)

1 Q. WHAT DO YOU RECOMMEND?

2 A. I recommend that NFGD evaluate its design day forecasting model to determine why the
3 model over forecasted demands during the three most recent winter seasons and modify
4 the model to address the Company's findings. This would include evaluating whether daily
5 rather than monthly usage should be used to forecast design day demands. The Company
6 should report its findings in next year's PGC proceeding and adjust its design day
7 projections to reflect its findings. Until this concern is resolved, I further recommend that
8 the Company not increase its interstate pipeline capacity entitlements.

9 Q. HAS THE COMPANY PROPOSED ACQUIRING ADDITIONAL CAPACITY
10 IN THIS PROCEEDING?

11 A. Yes. The Company is proposing to acquire an additional 5,000 Dth of NFG Supply capacity
12 for the winter of 2024-2025.⁵ As stated above, I do not recommend that NFGD be permitted
13 to increase its capacity entitlements by this amount this year.

14 **IV. AUDIT FINDINGS**

15 Q. PLEASE SUMMARIZE THE BUREAU OF AUDITS' FINDINGS IN ITS
16 AUDIT REPORT FILED IN DOCKET NO. D-2022-3031418.

17 A. The purchased gas cost audit conducted by the Bureau of Audits in Docket No. D-2022-
18 3031418 for the period December 2017 – November 2020 found that NFGD should refund

⁵ Direct Testimony of Lisa A. Petko, page 12, lines 10-13.

1 \$111,398 to PGC customers. This refund was attributable to errors in the reporting of prior
2 period adjustments and the amortization of over/under collection balances during the audit
3 period. The audit recommended that NFGD credit \$111,398 to PGC customers in its next
4 PGC filing.

5 Q. SHOULD THE \$111,398 BE RETURNED TO PGC CUSTOMERS IN NFGD’S
6 NEXT PGC FILING?

7 A. Yes. The \$111,398 should be returned to PGC customers in the Company’s May 2024
8 quarterly PGC filing.

9 Q. DID THE AUDIT REPORT INCLUDE ANY OTHER RECOMMENDATIONS?

10 A. Yes. The audit report also recommended that NFGD implement controls to prevent, detect,
11 and correct the type of errors found in the audit report that lead to the \$111,398 PGC credit.

12 Q. WHAT DO YOU RECOMMEND?

13 A. I recommend that NFGD immediately begin evaluating and implementing controls to
14 prevent errors such as those found in the audit report, and identify and report the controls
15 it has implemented in next year’s annual PGC filing.

16
17 **V. CERTIFIED NATURAL GAS**

18 Q. WHAT IS CNG?

19 A. CNG is natural gas that has been evaluated and verified by an independent third-party to
20 have been produced with reduced greenhouse gas (“GHG”) emissions and environmental
21 impacts, beyond current environmental regulations.

22 Q. WHAT ARE SOME OF THE BENEFITS OF CNG?

23 A. CNG is a low carbon gas produced from certified wells. There are a number of ways to
24 reduce methane emissions, including reducing leaks from the production, storage, and the
25 transportation of natural gas. Certified wells can reduce methane emissions by up to 80%

1 from traditional wells. CNG provides the same reliability as conventional natural gas and
2 is compatible with all existing natural gas infrastructure.

3 Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO CNG?

4 A. The Company is proposing to implement a three-year pilot program designed to purchase
5 CNG. The pilot program will limit the incremental costs associated with CNG premiums
6 to \$175,000 per year.

7 Q. WHAT WILL THE \$175,000 OF ANNUAL FUNDING PAY FOR?

8 A. The \$175,000 of annual funding will cover the premium associated with procuring certified
9 natural gas. The Company believes that this premium is approximately \$0.03-\$0.07 Dth.
10 This level of funding will allow the Company to purchase approximately 2.5 to 6.0 Bcf of
11 CNG per year.

12 Q. WHAT IS THE COMPANY ATTEMPTING TO ACHIEVE WITH CNG PILOT
13 PROGRAM?

14 A. The CNG Pilot Program will provide the Company with a cost-effective opportunity to test
15 CNG as a new reliable, low cost and low carbon energy source for its customers. In
16 particular, the CNG Pilot Program allows the Company to gain market knowledge related
17 to the quantification and certification of methane reductions associated with procuring
18 CNG that has lower methane intensity compared to national and regional methane emission
19 averages of conventional natural gas.

20 Q. DO YOU HAVE ANY OBSERVATIONS CONCERNING NFGD'S
21 PROPOSAL TO PURCHASE RNG FOR PGC CUSTOMERS?

22 A. The damage that may be caused by global warming, largely caused by GHG, is a significant
23 world-wide concern. To begin to address this concern states are adopting laws and policies
24 that address carbon emissions associated with the energy delivered to customers. Should
25 similar federal, state, or local legislation be adopted affecting NFGD, the CNG pilot

1 program proposal may provide the Company and other Pennsylvania NGDCs with the
2 experience and knowledge to minimize the costs associated with implementing GHG
3 reduction strategies. .

4 Q. SHOULD NFGD'S PROPOSED CNG PILOT PROGRAM BE APPROVED?

5 A. NFGD proposed CNG pilot program should be approved. In next year's proceeding,
6 NFGD should: (1) report the daily quantities of CNG purchased; (2) identify the PGC rate
7 impact of its CNG purchases; and (3) identify the BTU content of its CNG purchases and
8 any impact of a change in BTU content from that of other purchases on usage.

9 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

10 A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
v : Docket No. R-2024-3045177
National Fuel Gas Distribution Corporation :

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 1, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: March 8, 2024

Signature:


Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc. 10480
Little Patuxent Parkway, Suite 300
Columbia, MD 21044-3575

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC	:	
UTILITY COMMISSION	:	
	:	
v.	:	DOCKET NO. R-2024-3045177
	:	
NATIONAL FUEL GAS	:	
DISTRIBUTION CORPORATION	:	

REBUTTAL TESTIMONY
OF
JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MARCH 22, 2024

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REBUTTAL TESTIMONY OF JEROME D. MIERZWA

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal with and Vice President of Exeter Associates, Inc. (“Exeter”). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement 1 on March 8, 2024.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain aspects of the direct testimony of Bureau of Investigation and Enforcement (“I&E”) witness Eryan A. Sakaya, and Office of Small Business Advocate (“OSBA”) witness Mark D. Ewen concerning the gas supply procurement practices of National Fuel Gas Distribution Corporation (“NFGD” or “Company”).

II. WITNESS: ESYAN A. SAKAYA

Bureau of Investigation and Enforcement

Q. WHAT IS CERTIFIED NATURAL GAS (“CNG”)?

A. CNG is natural gas that has been evaluated and verified by an independent third-party to have been produced with reduced greenhouse gas (“GHG”) emissions and environmental impacts, beyond current environmental regulations.

Q. WHAT ARE SOME OF THE BENEFITS OF CNG?

A. CNG is a low carbon gas produced from certified wells. There are a number of ways to reduce methane emissions, including reducing leaks from the production, storage, and the

1 transportation of natural gas. Certified wells can reduce methane emissions by up to 80%
2 from traditional wells. CNG provides the same reliability as conventional natural gas and
3 is compatible with all existing natural gas infrastructure.

4 Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO CNG?

5 A. The Company is proposing to implement a three-year Pilot Program designed to purchase
6 CNG. The pilot program will limit the incremental costs associated with CNG premiums
7 to \$175,000 per year.

8 Q. WHAT WILL THE \$175,000 OF ANNUAL FUNDING PAY FOR?

9 A. The \$175,000 of annual funding will cover the premium associated with procuring certified
10 natural gas. The Company believes that this premium is approximately \$0.03-\$0.07 Dth.
11 This level of funding will allow the Company to purchase approximately 2.5 to 6.0 Bcf of
12 CNG per year. This level of funding would increase NFGD's PGC rate by less than 1 cent
13 per Mcf per year.

14 Q. WHAT IS THE COMPANY ATTEMPTING TO ACHIEVE WITH THE CNG
15 PILOT PROGRAM?

16 A. The CNG Pilot Program will provide the Company with a cost-effective opportunity to test
17 CNG as a new reliable, low cost and low carbon energy source for its customers. In
18 particular, the CNG Pilot Program allows the Company to gain market knowledge related
19 to the quantification and certification of methane reductions associated with procuring
20 CNG that has lower methane intensity compared to national and regional methane emission
21 averages of conventional natural gas.

1 Q. IS THE PURCHASE OF HIGHER COST CNG A CONCERN TO MR.
2 SAKAYA?

3 A. Yes. Mr. Sakaya expresses a concern that the potential purchase of higher cost CNG may
4 be inconsistent with NFGD's obligation to pursue a least cost procurement strategy.¹

5 Q. WHAT IS YOUR RESPONSE TO MR. SAKAYA?

6 A. The damage that may be caused by global warming largely caused by GHG is a significant
7 world-wide concern. To begin to address this concern, states have begun adopting laws and
8 policies that address carbon emissions associated with the energy delivered to customers.
9 Should federal state, or local legislation be adopted affecting NFGD, the CNG Pilot
10 Program may provide the Company and other Pennsylvania natural gas distribution
11 companies ("NGDCs") with the experience and knowledge to minimize the costs
12 associated with implementing GHG reduction strategies. While CNG may be slightly more
13 expensive than gas from traditional supply sources, I believe it important that utilities such
14 as NFGD be prepared to address changes in operations due to what appear to be inevitable
15 new laws and policies designed to reduce GHG emissions. I believe the incremental costs
16 associated with the CNG pilot program are reasonable and prudent given the anticipated
17 charges and may well save ratepayers costs in the long run.

¹ I&E Statement No. 1, p. 10, lines 10-14.

1
2 **III. WITNESS: MARK D. EWEN**
3 **Office of Small Business Advocate**

4 Q. DOES MR. EWEN ALSO EXPRESS ALSO EXPRESS A CONCERN THAT
5 THE CNG PILOT PROGRAM IS INCONSISTENT WITH NFGD'S
6 OBLIGATION TO PURSUE A LEAST COST PROCUREMENT STRATEGY
7 AND WHAT IS YOUR RESPONSE?

8 A. Yes. Mr. Ewen also claims that the CNG Pilot Program is inconsistent with NFGD's
9 obligation to pursue a least cost procurement strategy.² I have already addressed this
10 concern in responding to Mr. Sakaya. As indicated in that response, the CNG Pilot Program
11 may well save ratepayers costs in the long run.

12 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

13 A. Yes, it does.

² OSBA Statement No. 1, page 3, lines 1-3.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

National Fuel Gas Distribution Corporation

Docket No. R-2024-3045177

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement 1R, are true and correct to the best of my knowledge, information, and belief in the interrogatory responses. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: March 22, 2024

Signature:


Jerome D. Mierzwa

Address:

Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA STATEMENT 1SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC	:	
UTILITY COMMISSION	:	
	:	
v.	:	DOCKET NO. R-2024-3045177
	:	
NATIONAL FUEL GAS	:	
DISTRIBUTION CORPORATION	:	

SURREBUTTAL TESTIMONY

OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MARCH 29, 2024

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SURREBUTTAL TESTIMONY OF JEROME D. MIERZWA

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal with and Vice President of Exeter Associates, Inc. (“Exeter”). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was filed as OCA Statement 1 on March 8, 2024, and my rebuttal testimony was filed as OCA Statement 1R on March 22, 2024.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony presented by National Fuel Gas Distribution Corporation (“NFGD” or “Company”) witnesses Gregory D. Harts, Lisa A. Petko, and Nicholas J. Hewa.

II. WITNESS: GREGORY D. HARTS

Q. WHAT DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY CONCERNING NFGD’S DESIGN DAY FORECASTING MODEL?

A. On pages 4 and 5 of my direct testimony, I recommended that the Company further analyze its design day forecasting model and address the concern that it appears to be overestimating the Company’s design day requirements. Until this concern is resolved, I further recommended that the Company not acquire the additional National Fuel Gas Supply Corporation (“NFG Supply”) capacity for the winter of 2024-2025 the Company has proposed in this proceeding.

Q. DOES MR. HARTS AGREE WITH YOUR RECOMMENDATION?

1 A. No. Mr. Harts contends my finding that the Company's model appears to be over
2 forecasting design day requirements is inappropriately based on the extrapolation of
3 usage per heating degree day (HDD) during three winter seasons that were warmer than
4 normal and typically experienced by the Company, and that usage per HDD tends to
5 be lower at lower temperatures.¹ Mr. Hart contends a linear extrapolation of actual
6 usage on warm days of 48, 53 and 51 HDDs to a design day of 74 HDD cannot be
7 exclusively relied upon because it can significantly underestimate design day usage.²
8 To support his position, Mr. Hart notes that the extrapolated design day estimate for
9 January 7, 2014, with 68 HDDs exceeded the Company's design day forecast for the
10 winter of 2013-2014.³

11 Mr. Harts contends that the January 7, 2014, experience demonstrates the
12 reasonableness of the Company's design day forecasting model and the model is not
13 intended to forecast usage for days that are significantly lower than 74 HDD. Mr. Harts
14 claims the model is intended to forecast usage when temperatures are extremely cold,
15 so that the Company can ensure that it has sufficient supply to provide reliable service
16 to customers. Based upon the 2014 winter, the Company's model is not overstating
17 capacity requirement when HDDs are close to 74.⁴

Q. WHAT IS YOUR RESPONSE TO MR. HARTS' CLAIMS?

18 A. While I agree with Mr. Harts that usage per HDD is typically higher at colder
19 temperatures, I would note that the Company's design day model also significantly
20 overestimated demands during the three-day peak period experienced during the winter
21 of 2014-2015. This three-day peak period was the coldest in the last ten years. During

¹ Distribution PGC Statement No. 4R page 2, line 8 - page 3, line 17.

² Distribution PGC Statement No. 4R page 3, lines 6 - 11.

³ Distribution PGC Statement No. 4R page 4, lines 7 - 12.

⁴ Distribution PGC Statement No. 4R page 4, line 13 - page 5, line 5.

1 the three-day peak period of the winter of 2014-2015, HDDs averaged 66. In fact,
2 during the three-day peak period in the winter of 2014-2015, design day HDDs of 74
3 were experienced. The design day forecast modeling approach used by the Company
4 for the winter of 2014-2015 is the same modeling approach currently utilized by the
5 Company. Table 1-SR identifies extrapolated demands and forecasted demands for the
6 three-day peak period of the winter of 2014-2015, as well as the HDDs experienced
7 each day.
8

Table 1-SR. Extrapolated Versus Forecasted Design Day Demands (Dth)				
Date	Extrapolated	Forecasted	Difference	HDD
February 14, 2015	412,012	463,496	(51,484)	57
February 15, 2015	387,074	463,496	(76,422)	74
February 16, 2015	390,626	463,496	(72,870)	68

9

Q. ON PAGE 11 OF YOUR DIRECT TESTIMONY YOU RECOMMENDED
THAT THE COMPANY SHOULD EVALUATE USING DAILY RATHER
THAN MONTHLY USAGE TO DEVELOP IS DESIGN DAY
FORECASTING MODEL. DOES MR. HARTS AGREE WITH THIS
RECOMMENDATION?

10 A. No. Mr. Harts claims that the Company does not obtain daily meter reading data for
11 the vast majority of its customers and, therefore, cannot utilize daily usage data to
12 develop a design day forecast.⁵

Q. WHAT IS YOUR RESPONSE TO MR. HARTS' CLAIM THAT THE
COMPANY DOES NOT OBTAIN DAILY METER READING DATA FOR
THE VAST MAJORITY OF ITS CUSTOMERS AND, THEREFORE,

⁵ Distribution PGC Statement No. 4R page 6, lines 1 - 6.

CANNOT DEVELOP A DESIGN DAY FORECAST BASED ON DAILY
USAGE?

1 A. Individual daily meter reading data for all customers is not necessary to develop a
2 design day forecasting model based on daily usage. Total daily usage by all customers
3 for which NFGD secures capacity to meet design day demands is necessary to develop
4 a design day forecast based on daily usage. This daily usage is readily available to the
5 Company as it was utilized by the Company to develop Exhibit LAP-3 which I discuss
6 on page 11 of my direct testimony. I would note that over the last 30 years I have
7 evaluated the gas procurement practices of approximately 40 different NGDCs. For
8 many of these NGDCs, I conduct annual reviews. NFGD is the only NGDC I can recall
9 which uses monthly data to develop to its total design day requirements forecast.

10 **III. WITNESS: LISA A. PETKO**

Q. ON PAGE 12 OF YOUR DIRECT TESTIMONY, YOU ALSO
RECOMMENDED THAT THE COMPANY NOT ACQUIRE THE 5,000
DTH OF NFG SUPPLY ADDITIONAL INTERSTATE CAPACITY IT IS
PROPOSING TO ACQUIRE UNTIL IT PERFORMS AN EVALUATION
OF ITS DESIGN DAY FORECASTING MODEL. DOES MR. PETKO
AGREE WITH THIS RECOMMENDATION?

11 A. No. Ms. Petko claims that based on the Company's design day forecast it is appropriate
12 for the Company to seek additional NFG Supply capacity. However, to maintain
13 capacity contract flexibility, the Company is proposing to limit the contract term for
14 this incremental capacity to no more than two years⁶.

Q. WHAT IS YOUR RESPONSE TO MS. PETKO'S CLAIM CONCERNING
THE ACQUISITION OF ADDITIONAL NFG SUPPLY CAPACITY?

⁶ Distribution PGC Statement No. 7R page 3, lines 1 - 8.

1 A. As just demonstrated, the Company's design day forecasts have at times shown a
2 tendency to significantly overestimate demands. It would be unreasonable for NFGD
3 to acquire additional interstate pipeline capacity until it corrects this tendency.
4 Maintaining capacity in excess of reasonably anticipated design day demands would
5 be inconsistent with least-cost gas procurement.

6 For all of the reasons in this testimony and in my direct testimony, I continue
7 to recommend that NFGD not acquire additional interstate pipeline capacity. With
8 respect to limiting the NFG Supply contract term to two years, I recommend that if the
9 Commission approves NFGD's acquisition of additional NFG Supply capacity, the
10 term of the contract be limited to one-year, and the Company should be required to re-
11 evaluate its design day forecasting model as I have recommended. This would limit the
12 adverse cost consequences for PGC customers of acquiring additional capacity if the
13 Company's re-evaluation subsequently determines that the acquisition of incremental
14 capacity was unnecessary.

15 **IV. WITNESS: NICHOLAS J. HEWA**

Q. WHAT ISSUE DOES MR. HEWA ADDRESS IN HIS REBUTTAL
TESTIMONY?

16 A. On page 12 of my direct testimony I noted that in Docket No. D-2022-3031418, the
17 Pennsylvania Public Utility Commission's Bureau of Audits found that NFGD should
18 refund \$111,398 to its PGC customers. I recommended that NFGD should refund the
19 \$111,398 to PGC customers in its May 2024 quarterly PGC filing.

Q. DOES MR. HEWA AGREE WITH THIS RECOMMENDATION?

20 A. No. Mr. Hewa has proposed that NFGD refund the \$111,398 to PGC customers in the
21 Company's annual August 1, 2024, PGC compliance filing.⁷ Mr. Hewa contends that

⁷ Distribution Statement No. 5R page 2, lines 9 - 11.

1 reflecting the refund in the May 2024 quarterly filing would be administratively
2 burdensome and complicate the reconciliation of E-Factor amounts that were
3 established in the Company's 2023 annual PGC filing.⁸

Q. DO YOU ACCEPT MR. HEWA'S PROPOSAL TO REFLECT THE
REFUND IN THE COMPANY'S ANNUAL AUGUST 1, 2014, PGC
COMPLIANCE FILING?

4 A. No. I continue to recommend that the refund be returned in May 2024, including
5 adding the appropriate interest charges.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

⁸ Distribution PGC Statement No. 5R page 2, lines 19 – 21.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

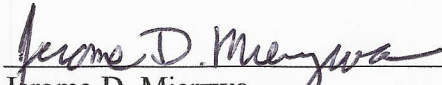
Pennsylvania Public Utility Commission	:	
v	:	Docket No. R-2024-3045177
National Fuel Gas Distribution Corporation	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 1SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: March 29, 2024

Signature:


Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc. 10480
Little Patuxent Parkway, Suite 300
Columbia, MD 21044-3575

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket No. R-2024-3045177
	:	
v.	:	
	:	
National Fuel Gas Distribution	:	
Corporation 1307(f)	:	

**ADMITTED TESTIMONIES AND EXHIBITS
BY THE OFFICE OF SMALL BUSINESS ADVOCATE**

The Office of Small Business Advocate (“OSBA”) intends to introduce the following evidence into the record in the above-captioned proceeding at the evidentiary hearings scheduled for April 3-4, 2024:

- OSBA Direct Testimony, labelled Statement No. 1 with Exhibit IEc-1, and signed Verification of Mark D. Ewen
- OSBA Rebuttal Testimony, labeled Statement No. 1-R with signed Verification of Mark D. Ewen



COMMONWEALTH OF PENNSYLVANIA

March 8, 2024

The Honorable Charece Z. Collins
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

**Re: National Fuel Gas Distribution Corporation's Purchased Gas Cost Filing Under
Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 / Docket
No. R-2024-3045177**

Dear Judge Collins:

Enclosed please find the Direct Testimony and Exhibits of Mark D. Ewen, labelled OSBA Statement No. 1, with Exhibit IEc-1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

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

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

Sincerely,

/s/ Steven C. Gray

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

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Mark D. Ewen
Parties of Record

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

PENNSYLVANIA PUBLIC UTILITY	:	
COMMISSION	:	
v.	:	
NATIONAL FUEL GAS DISTRIBUTION	:	Docket No. R-2024-3045177
CORPORATION (PURCHASED GAS COSTS,	:	
66 PA.C.S. SECTION 1037(f))	:	

Direct Testimony of

MARK D. EWEN

On Behalf of the

Pennsylvania Office of Small Business Advocate (OSBA)

Topics:

Certified Natural Gas Pilot Program

Date Served: March 8, 2024

Date Submitted for the Record: _____

DIRECT TESTIMONY OF MARK D. EWEN

1 **1. Introduction and Context**

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

3 A. My name is Mark D. Ewen. I am a Principal and President of Industrial Economics,
4 Incorporated (“IEC”), a consulting firm located at 2067 Massachusetts Avenue, Cambridge,
5 MA 02140. My consulting practice focuses on regulatory and environmental economics,
6 expert case management and economic damages estimation in a variety of litigation
7 contexts, and financial analysis. I obtained a B.A degree in Economics and Political Science
8 from the University of North Dakota, and a Master of Public Policy degree from the
9 University of Michigan. My résumé and a listing of the expert testimony that I have filed in
10 various litigation and utility regulatory proceedings are attached in Exhibit IEC-1.

11 **Q. Please describe your assignment in this matter.**

12 A. OSBA requested that I review the submission by National Fuel Gas Distribution
13 Corporation (“NFG” or “the Company”) in support of its 2024 annual 1307(f) Purchased
14 Gas Cost (“PGC”) filing, to determine whether the proposal is consistent with sound
15 economics and regulatory policy, and fairly treats small business customers. This testimony
16 provides a review of the Company’s proposed pilot program to procure certified natural gas
17 (“CNG”).

18 **Q. Please provide an overview of the salient features of the Company’s proposed pilot
19 program for CNG.**

20 A. As outlined in NFG Statement No. 2 (pp. 8 – 13), the key features of the proposed pilot
21 include:

- 22 • CNG, or Independently Certified Gas as it is sometimes called, is natural gas primarily
23 produced in a way that reduces methane emissions relative to current regulatory
24 requirements. The certification is awarded by a third party auditing entity, based upon
25 that entity’s own certification measures and standards. The Company represents that
26 CNG provides the same reliability as conventional natural gas and is compatible with
27 existing natural gas infrastructure.

- NFG is proposing to implement a three year pilot program to procure CNG, with an incremental cost of \$175,000 per year to cover the higher premiums for this product. The Company represents that this price premium is approximately \$0.03-\$0.07 per dekatherm for the purchased volumes.
- NFG would implement the purchases under its current Gas Cost Management Plan and seek least cost CNG supplies through a formal RFP process. It would utilize the certification process and standards of two alternative organizations: MiQ, launched as a partnership of RMI (formerly the Rocky Mountain Institute) and global sustainability consultancy SYSTEMiQ; and OGMP, the Oil and Gas Methane Partnership created by the Climate and Clean Air Coalition.
- NFG's goal is to use the pilot to identify and purchase CNG from certified operators, gain market knowledge related to the quantification and certification of methane reductions, and test CNG as a lower carbon energy source for its customers. In addition, the company intends to quantify CO₂e (carbon dioxide equivalent) abated by measuring the methane intensity of the CNG versus the intensity of traditionally extracted natural gas.

2. **Discussion of Issues Concerning the Proposed CNG Pilot Program**

Q. Do you have any concerns with the proposed pilot program?

A. Yes. First, I am not aware of any State or Federal statutory or regulatory requirement to procure CNG at the current time. As such, it appears that this proposal to purchase higher cost gas may run afoul of least cost gas procurement requirements. Second, it is not clear how NFG intends to offer this supply option to customers, including whether it contemplates voluntary participation or general cost recovery across all customers. This uncertainty leads to concerns about whether related rates are just and reasonable. Third, natural gas customers can shop for gas suppliers in Pennsylvania. The Company has made no representations as to whether CNG is already an option for its customers, and there is no evidence of a CNG option in NFG's tariff.

Further, and with respect to these issues in general, I am advised by counsel that incurring additional costs for the procurement of CNG that has no direct benefit to ratepayers conflicts with the utility's legal obligation to procure gas at least cost.

Q. Do have any other concerns regard the proposed CNG pilot program.

A. I do. The Company has stated that a primary aim is to "test the value propositions of the pilot for its customers." (St. No. 2, p. 13). It strikes me that most of these value propositions can be assessed outside of any pilot program, or prior to engaging in a pilot. For example, one goal is to "gain market knowledge related to the quantification and certification of methane reductions associated with procuring CNG..." (St. No. 2, p. 13). A quick internet search indicates that there is publicly available information concerning the structure, viability, and integrity of the certifying organizations, along with information concerning the efficacy and stringency of the audit and certification process. In addition, the Company intends to measure carbon dioxide abatement as part of the pilot. However, potential methane abatement levels related to CNG supply can be estimated independently of any pilot program with publicly available data.

Q. What are your recommendations for addressing these concerns?

A. This program is not required by law or regulation, has unclear outcomes with respect to least cost procurement and rate reasonableness requirements, and can potentially be offered by other suppliers. In addition, many of the stated reasons for the program and its goals can be assessed independently of any pilot.

For these reasons, I recommend that the proposal be denied. Absent a denial, the Company should complete a more comprehensive review of the program structure and implementation before proceeding. This review would include a more detailed assessment of market availability of CNG supply, a specific plan for offering this supply option to customers, and quantification of potential CO₂e abatement impacts and other environmental benefits.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

MARK D. EWEN

Overview

Mr. Ewen has a strong background in applied economics, empirical methodologies, and financial analysis. As a Principal at Industrial Economics, Incorporated (IEc), he focuses on expert case management and economic damages estimation in a variety of litigation contexts, regulatory and environmental economics, and financial analysis. Within his areas of expertise, Mr. Ewen has been qualified as an expert witness before judicial and regulatory bodies (see schedule of testimony and appearances). He has also served as a Managing Director of the firm.

Education

Master of Public Policy, University of Michigan

Bachelor of Arts, summa cum laude in Economics and Political Science, University of North Dakota

Project Experience

Examples of his project work include the following:

Mr. Ewen has participated in various proceedings concerning energy markets and regulated utilities. These efforts, which focus on issues related to cost allocation and rate design, include working on behalf of industry and consumer intervenor groups in rate-making cases before the public utility commissions in Pennsylvania and Alberta, Canada, and the U.S. Postal Rate Commission. For example, for the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**, he has provided consulting and analytic support relating to electricity and natural gas tariff design, revenue requirements, and other regulatory initiatives concerning electrical and natural gas distribution utilities. For the **RHODE ISLAND ATTORNEY GENERAL**, Mr. Ewen conducted a due diligence review of PPL's proposed acquisition of Narragansett Electric Company and its potential impacts on the state's ratepayers.

For the **NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA) AND DEPARTMENT OF PUBLIC SERVICE (DPS)**, Mr. Ewen provided expert services assessing the economic impacts to municipal governments of extended electricity outages related to Tropical Storm Isaias. As part of this work, he constructed a model to estimate various costs of incremental staffing requirements for over 500 localities, including excess overtime, surge time (i.e., bringing on extra staff for outage response coordination and logistics), and idle time (e.g., crews waiting extended periods for downed lines to be de-energized). The review also included consideration of other direct costs, including, among others: effects to water systems; delivery of bottled water; operation of generators; and other constraints on the provision of essential governmental services. The litigation was settled to the satisfaction of the involved parties.

For the **NYSERDA AND NEW YORK DPS**, Mr. Ewen directed the development of a Generic Environmental Impact Statement (GEIS), pursuant to the requirement of the State Environmental Quality Review Act (SEQRA) that assessed the environmental and economic impacts of the "Reforming the Energy Vision" and "Clean Energy

Fund” initiatives within the state. He also directed the preparation of a Supplemental EIS to assess the environmental and economic impacts of the newly proposed Clean Energy Standard (CES). The CES is being developed to support the state’s goal of supplying 50 percent of electricity demand with renewable generation resources by the year 2030. More recently, he directed the development of a model to assess the financial viability of various waste-to-energy technologies, and related social welfare benefits. This model uses detailed capital budgeting scenarios for specific facilities to generate forecast scenarios.

For the **U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF OCEAN ENERGY MANAGEMENT (BOEM)**, directing an assessment of the Bureau’s approach to calculating and presenting the operating fee included in offshore wind leases under BOEM’s jurisdiction. As part of this engagement, IEc provided a number of recommendations for simplifying the implementation of the operating fee formula and identified available data sources and approaches to estimating individual components of the fee formula. The review also addressed the structure and levels of fees associated with operations of renewable wind energy projects in the U.S. and worldwide. More recently, IEc has been supporting the development of Standard Operating Procedures for the fee calculation and lease management process. The overall goal is to provide information resources and a methodological approach that will allow lessees to derive accurate data for fee equation variables efficiently and consistently, and for BOEM to present the fee calculation clearly in the lease.

For **NYSERDA**, conducting a market analysis examining the potential economic development opportunities that could accrue in New York from hydrogen playing a role in achieving components of its Climate Leadership and Community Protection Act.

For the **U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF OCEAN ENERGY MANAGEMENT**, managed the development of a model to assess the economic and fiscal impacts of offshore oil and gas activity in the Gulf of Mexico and other BOEM OCS regions. This model, the Lifecycle Impacts Model (LCIM), assesses the economic and fiscal impacts associated with a specific lease or group of leases, over the time horizon of the lease(s). IEc’s framework for the model was to build a capital budgeting forecasting tool for lease development, yielding estimates of industry expenditures, OCS revenues, industry profits, and employment impacts for a single lease or a set of leases. A key component of model development was to dynamically simulate the complex and unique timing parameters of lease development, incorporating the influence of critical exogenous factors like market prices and lease geology.

For the **U.S. COAST GUARD, NATIONAL POLLUTION FUNDS CENTER**, Mr. Ewen provides ongoing support to the NPFC in adjudicating damages claims resulting from oil spills. These claims include damages for business interruption, lost profits, property damage or value diminution, increased costs, and lost wages or employment, among other categories. Cases have also included damages for contract delays to construction projects and shipping demurrage. Industry sectors that Mr. Ewen has evaluated include: *electricity generation (nuclear and coal); railroads; cruise ships; oil ship transport; lodging and tourism; food and beverage; gambling; fisheries; marinas; real estate development, oil and gas development; and oil refining.*

Mr. Ewen’s analytic work includes expert financial analysis and economic damages estimation in the context of general litigation and environmental enforcement actions. These efforts include assessing damages in breach of contract, nuisance, and cost recovery actions, and assessing the financial capabilities and economic benefit of noncompliance of firms accused of environmental violations. Clients in this area of his practice include the **U.S. DEPARTMENT OF JUSTICE, U.S. COAST GUARD, U.S. ENVIRONMENTAL PROTECTION AGENCY, STATES,** and private parties.

Testimony and Appearances

Mr. Ewen has provided testimony or appeared in the following cases and regulatory proceedings.

On behalf of Attorney General of the State of Rhode Island, submitted testimony before the Rhode Island Division of Public Utilities and Carriers concerning due diligence and related reviews of PPL Corporation's proposed acquisition of Narragansett Electric Company from National Grid USA (Docket No. D-21-09, November 2021).

Expert report and deposition testimony concerning economic damages and related financial matters, *Seaplane Adventures, LLC, vs. County of Marin, California*; expert report filed September 2021, deposition testimony given September 2021.

Expert reports and deposition testimony on bankruptcy reorganization plan feasibility and related financial matters, *in re: First Energy Solutions Corp., et al., Debtors, Case No. 18-50757*; expert reports filed July 2019, deposition testimony given August 9, 2019.

Expert declaration concerning economic damages and related financial matters, *in re: Outer Banks Power Outage Litigation, all actions, No. 4:17-CV-141-D*, March 2018.

Expert report and deposition testimony on Economic Damages in *State of Alaska v. Williams Alaska Petroleum, Inc., et al., Case No. 4FA-14-01544 CI*; expert report filed December 2016, deposition testimony given February 15, 2017.

Expert reports and deposition testimony on Economic Benefit in *Sierra Club v. Energy Future Holdings Corp. et al., Case No. 5:10-cv-156 (E.D. Tex.)* and *Sierra Club v. Energy Future Holdings Corp. et al., Case No. 6:12-cv-108 (W.D. Tex.)*; expert reports filed in June and July 2013, deposition testimony given August 2013. Trial testimony given in Case No. 6:12-cv-108 (W.D. Tex.) in March 2014.

Expert testimony on ability-to-pay provided, in the matter of Mercury Vapor Processing Technologies, Inc., et al. (No. RCRA-05-2010-0015), July 2011.

Expert Declaration in a patent case concerning economic and financial matters in the context of environmental credits valuation -- In re Patent Application of: Jeff Andrienas et al., Application No.: 12/328,219, For: VALUING ENVIRONMENTAL CREDITS, submitted June 2011.

Expert report and deposition testimony on financial matters in Evansville Greenway and Remediation Trust v. Southern Indiana Gas and Electric Company, Inc., et al. (03:07-cv-0066-SEB-WGH); expert report filed July 2009, deposition testimony given January 2010.

Expert testimony on ability-to-pay provided, in the matter of Robert J. Heser, Andrew J. Heser, and Heser Farms (No. CWA-05-2006-0002), May 2007.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning tariff design issues for Columbia Gas of Pennsylvania (Docket No. R-00049783, May 2005).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning cost allocation, revenue assignment, and rate design for Pennsylvania Power and Light (Docket No. R-00049255, August 2004).

Expert report on economic damages in United States v. Southern California Edison No. CIV. F-01-5167 OWW DLB (E.D. Cal.), July 2004; deposition testimony provided September 2004.

Expert testimony on ability-to-pay provided in U.S. v. Peter Thorson, Managed Investments, Inc., Construction Management, Inc., and Gerke Excavating, Inc. (No. 03-C-0074), May 2004.

Expert testimony on ability-to-pay provided in U.S. v. Paul A. Heinrich and Charles Vogel Enterprises, Inc. (No. 03-C-0075-S), October 2003.

Expert testimony on ability-to-pay provided in the matter of Dearborn Refining Company (No. RCRA-05-2001-0019), February 2003.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for PFG Gas and Northern Penn Gas (Docket No. R-00027389, July 2002).

Expert report and testimony on economic damages in Carol Marmo et al. v. IBP, Inc.; expert report filed March 2002, deposition testimony given June 2002, September 2004, and testimony at trial given February 2005.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for National Fuel Gas Distribution Corporation (Docket No. R-00016789, March 2002).

On behalf of the Office of the Consumer Advocate, providing testimony before the United States Postal Rate Commission regarding cost allocation of city carrier street time costs. Docket No. R2000-1, July 11, 2000.

Expert report and declaration on ability-to-pay in re Indspec Chemical Corporation and Associated Thermal Services, Inc., and related testimony in U.S. EPA administrative court on February 24, 1998 (No. CAA-III-086).

Expert report on ability-to-pay in re Harrisburg Hospital and First Capital Insulation, Inc. and related testimony in U.S. EPA administrative court on October 8, 1997 (No. CAA-III-076).

2022

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	
NATIONAL FUEL GAS DISTRIBUTION	:	Docket No. R-2024-3045177
CORPORATION (PURCHASED GAS COSTS,	:	
66 PA.C.S. SECTION 1037(f))	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Direct Testimony labelled OSBA Statement No. 1 and associated Exhibit IEC-1 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: 3/8/2024



Mark D. Ewen



COMMONWEALTH OF PENNSYLVANIA

March 22, 2024

The Honorable Charece Z. Collins
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

**Re: National Fuel Gas Distribution Corporation's Purchased Gas Cost Filing Under
Section 1307(f) of the Public Utility Code and 52 Pa. Code §§ 53.64 and 53.65 / Docket
No. R-2024-3045177**

Dear Judge Collins:

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

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

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

Sincerely,

/s/ Rebecca Lyttle

Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Mark D. Ewen
Parties of Record

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

PENNSYLVANIA PUBLIC UTILITY	:	
COMMISSION	:	
v.	:	
NATIONAL FUEL GAS DISTRIBUTION	:	Docket No. R-2024-3045177
CORPORATION (PURCHASED GAS COSTS,	:	
66 PA.C.S. SECTION 1037(f))	:	

Rebuttal Testimony of

MARK D. EWEN

On Behalf of the

Pennsylvania Office of Small Business Advocate (OSBA)

Topics:

Certified Natural Gas Pilot Program

Date Served: March 22, 2024

Date Submitted for the Record: _____

REBUTTAL TESTIMONY OF MARK D. EWEN

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

2 A. My name is Mark D. Ewen. I submitted direct testimony earlier in this proceeding, and my
3 qualifications were detailed therein.

4 **Q. What is the purpose of this rebuttal testimony?**

5 A. This testimony responds to recommendations concerning NFG's proposed certified natural
6 gas (CNG) pilot program provided by Jerome D. Mierzwa, representing the Pennsylvania
7 Office of Consumer Advocate ("OCA"), and Eryan A. Sakaya, representing the
8 Pennsylvania Bureau of Investigation and Enforcement ("I&E").

9 **Q. Please briefly summarize the salient features of the proposed CNG pilot program.**

10 A. As outlined in NFG Statement No. 2 (pp. 8 – 13), the key features of the proposed pilot
11 include: procure CNG supplies over a three year period; budget \$175,000 in incremental
12 costs per year to cover the higher premiums for this product; and conduct various market
13 and emissions analyses to evaluate the initiative.

14 **Q. Please briefly summarize your concerns and recommendations concerning the
15 proposed pilot program?**

16 A. As I discuss in my direct testimony, this program is not required by law or regulation, can
17 potentially be offered by other suppliers, and many of the stated reasons for the program
18 and its goals can be assessed independently of any pilot. Further, I am advised by counsel
19 that incurring additional costs for the procurement of CNG that has no direct benefit to
20 ratepayers conflicts with the utility's legal obligation to procure gas at least cost.

21 I therefore recommended that the proposal be denied. Absent a denial, I recommended that
22 the Company should complete a more comprehensive review of the program structure and
23 implementation before proceeding. This review would include a more detailed assessment
24 of market availability of CNG supply, a specific plan for offering this supply option to
25 customers, and quantification of potential CO₂e abatement impacts and other environmental
26 benefits.

1 **Q. Do I&E Witness Sakaya and OCA Witness Mierzwa agree with your**
2 **recommendations?**

3 A. It appears Witness Sakaya does agree with my conclusions and Witness Mierzwa does not.

4 **Q. What are Witness Sakay's conclusions?**

5 A. The testimony (I&E Statement No. 1) recommends the proposed pilot program be denied
6 on concerns that it does not adhere to the Company's lease cost procurement obligation and
7 uncertainty about the validity of third-party certifications specific to methane emissions
8 mitigation (p. 8). In the event the Commission does approve the pilot program, the
9 Company should be required to show how the purchase of CNG complies with least cost
10 procurement requirements for all gas supplies and provide a report in future 1307(f) filings
11 describing the details of the program for the duration of the pilot (p. 10).

12 **Q. What are Witness Mierzwa's conclusions?**

13 A. The testimony (OCA Statement No. 1) recommends approval of the proposed pilot, with a
14 requirement that in next year's proceedings the Company report the daily quantities of CNG
15 purchased, identify the PGC rate impact of its CNG purchases, and identify the BTU content
16 of it CNG purchases and any impact of a change in BTU content from that of other purchases
17 on usage (p. 15).

18 **Q. Please address Witness Mierzwa's recommendations**

19 A. His recommendation for approval appears to rely on two primary factors. First, it parrots
20 the Company's assertion that the pilot will provide an opportunity to test CNG as a lower
21 carbon intensive option for its customers, allowing it to gain market knowledge related to
22 the quantification and certification of methane reductions associated with CNG (p. 14). As
23 I noted in my direct testimony, however, assessment of the emissions benefits and market
24 potential for the volumes contemplated in the pilot can be completed independently of the
25 expenditure of \$525,000 over the next three years. Second, it notes that, due to greenhouse
26 gas emissions being a significant global concern, various governmental jurisdictions are
27 adopting laws and policies that address carbon emissions associate with the energy delivered
28 to customers (p. 14). The testimony goes on to aver that, should similar legislation be
29 adopted that affects NFG, the pilot program may provide the Company and other NGDCs
30 with the experience and knowledge to minimize costs associated with greenhouse gas

1 emission reduction strategies (p. 15). I would again submit that such goals can be achieved
2 independently of any pilot program. In addition, it seems possible that other gas suppliers
3 could provide a CNG option to those customers that may prefer such an option.

4 **Q. Have you changed your opinion based upon the testimony of Witness Mierzwa?**

5 A. I have not. The testimony provides no further justification for the pilot beyond what the
6 Company has proffered, it does not consider important least cost procurement requirements,
7 and overstates the information and experience development potential of pilot
8 implementation. It is not clear to me that the benefits of such a pilot exceed its \$525,000
9 cost. I do note, however, that should a pilot be approved by the Commission, all three
10 witnesses propose stringent analytic and reporting requirements for the duration of the
11 program.

12 **Q. Does this conclude your rebuttal testimony?**

13 A. Yes, it does.
14
15

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	
NATIONAL FUEL GAS DISTRIBUTION CORPORATION (PURCHASED GAS COSTS, 66 PA.C.S. SECTION 1037(f))	:	Docket No. R-2024-3045177
	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Rebuttal Testimony labelled OSBA Statement No. 1-R are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: 3/22/2024



Mark D. Ewen

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket No. R-2024-3045177
	:	C-2024-3045469
v.	:	
	:	
National Fuel Gas Distribution	:	
Corporation 1307(f)	:	

CERTIFICATE OF SERVICE

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

The Honorable Charece Z. Collins
Administrative Law Judge
Pennsylvania Public Utility Commission
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/s/ Rebecca Lyttle
Rebecca Lyttle
Assistant Small Business Advocate
Attorney ID No. 201399

DATE: March 29, 2024