

The Narragansett Electric Company d/
b/a Rhode Island Energy

INTERIM GAS COST RECOVERY

Pre-Filed Direct Testimony and
Attachments of:

James M. Stephens and
Tyler G. Shields

March 31, 2026

Submitted to:
Rhode Island Public Utilities Commission RIPUC
Docket No. 25-22-NG

Submitted by:



Rhode Island Energy™

a PPL company

Andrew S. Marcaccio
Senior Counsel
PPL Services Corporation
AMarcaccio@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-4263



March 31, 2026

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 25-22-NG - The Narragansett Electric Company d/b/a Rhode Island Energy Interim Gas Cost Recovery Filing

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the “Company”), enclosed, please find the Company’s Interim Gas Cost Recovery (“GCR”) Filing. The Company respectfully requests that the Public Utilities Commission (“PUC”) approve the proposed GCR factors, as listed below, for usage on and after May 1, 2026.

GCR Factors	Current Rate	Proposed Rate*	Source
High Load Factor	\$0.5775 per therm	\$0.9088 per therm	GCR Interim Filing Attachment TGS-1, Page 1, Line 8, Column (c)
Low Load Factor	\$0.6342 per therm	\$0.9655 per therm	GCR Interim Filing Attachment TGS-1, Page 1, Line 8, Column (d)

* For bill impacts, please see Rate and Bill Impacts section below.

Background

Every year, in the late summer/fall, the Company submits a GCR filing through which the Company adjusts gas rates to recover the costs of gas supply. On October 27, 2025, the PUC approved the currently-in-effect GCR factors for usage on and after November 1, 2025. Generally, the GCR factors are changed once per year. However, when circumstances warrant, the Company is permitted to seek approval of interim GCR factors in order to avoid a substantial under or over collection. This interim GCR filing is necessary because actual gas costs have increased above the levels projected in the Company’s initial GCR filing submitted in late summer/fall. These higher costs are primarily the result of the extreme cold weather experienced from late January through early February 2026, which drove substantially higher demand for natural gas for both heating and power generation. When combined with regional gas supply constraints, this elevated demand led to a sharp increase in the commodity prices at which the Company was required to procure gas supplies.

Legal Basis

The legal basis for this filing is the Gas Cost Recovery Clause in the Company's Gas Tariff, RIPUC RIE-GAS No. 101, Section 2, Schedule A, Part 1.2. The pertinent language reads as follows:

In the event of any change subsequent to the November effective date which would cause the estimate of the Deferred Gas Cost Balance to differ from zero by an amount greater than five percent (5%) of the Company's gas revenues, the Company may make a Gas Charge filing designed to eliminate that non-zero balance.

The Gas Tariff provides that the Company is to make an interim filing at least 60 days prior to the effective date, unless otherwise permitted by the PUC. In this case, the Company is respectfully requesting the interim GCR factors go into effect in 30 days on May 1, 2026, as opposed to 60 days. The reasons for the request are explained in the Company's Motion for an Expedited Effective Date.

Rate and Bill Impacts for Gas Customers

As filed, the Company is requesting approval to increase the current High Load GCR and Low Load GCR factors by \$0.325 per therm or \$0.3313 per therm when including the gross up for uncollectibles. The High Load group includes Residential Non Heating, Large High Load, and Extra Large High Load customers and the Low Load group includes Residential Heating, Small C&I, Medium C&I, Large Low Load, and Extra Large Low Load customers. The GCR factor is one of six charges on a Residential Heating customer's bill. The resulting impact on a typical gas customer using 160 therms is an increase of \$54.64 or 14.8 percent from May 1, 2026 through October 31, 2026.

Summary of Filing

This filing consists of the following documents:

- Direct Testimony of James M. Stephens – Company Witness Stephens discusses the Company's gas supply portfolio and the major factors that have contributed to the change in gas costs and associated deferred gas cost balance.
- Direct Testimony of Tyler G. Shields – Company Witness Shields supports the revised GCR factors for effect May 1, 2026, and presents resulting bill impacts. His testimony includes the following attachments:
 - Attachment TGS-1 - Proposed Gas Cost Recovery Factors
 - Attachment TGS-2 - Estimated Deferred Gas Cost Balance without Revised GCR
 - Attachment TGS-3 - Estimated Deferred Gas Cost Balance with Revised GCR
 - Attachment TGS-4 - Bill Impact Analysis

Stephanie De La Rosa, Commission Clerk
Docket No. 25-22-NG – Interim Gas Cost Recovery Filing
March 31, 2026
Page 3 of 3

Thank you for your attention to this filing. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

A handwritten signature in blue ink, appearing to read "Andrew S. Marcaccio".

Andrew S. Marcaccio

Enclosures

cc: Docket No. 25-22-NG Service List

**STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION**

<p>THE NARRAGANSETT ELECTRIC) COMPANY d/b/a RHODE ISLAND ENERGY) 2025 DISTRIBUTION ADJUSTMENT CHARGE AND) 2025 GAS COST RECOVERY FILINGS)</p>	DOCKET NO. 25-22-NG
---	---------------------

**MOTION OF THE NARRAGANSETT ELECTRIC COMPANY
FOR EXPEDITED EFFECTIVE DATE OF PROPOSED RATE CHANGE**

The Narragansett Electric Company d/b/a Rhode Island Energy (“Rhode Island Energy” or the “Company”) hereby respectfully requests, pursuant to R.I. Gen. Laws § 39-3-11 and 810-RICR-00-00-1.16, that the Public Utilities Commission (“Commission”) grant its request for an interim adjustment of the Company’s now effective Gas Cost Recovery (“GCR”) factors for effect May 1, 2026.

In support of this motion, the Company states as follows:

1. On October 27, 2025 the Commission approved the GCR factors that are now in effect for usage on and after November 1, 2025.
2. The Company’s tariff for gas service, RIPUC RIE-GAS No. 101 (the “Gas Tariff”), Section 2, Schedule A, Item 1.2, provides for the interim adjustment of GCR factors, “[i]n the event of any change subsequent to the November effective date which would cause the estimate of the Deferred Gas Cost Balance to differ from zero by an amount greater than five percent (5%) of the Company’s gas revenues.”
3. As explained in the accompanying pre-filed direct testimonies of Company witnesses James M. Stephens and Tyler G. Shields, events subsequent to the November 1, 2025

effective date of the now effective GCR factors have led to the Company's Deferred Gas Cost Balance (as defined in the Gas Tariff) to differ from zero by more than 14 percent as of February 28, 2026. The currently forecasted under-recovery of gas costs as of October 31, 2026 is \$25,775,273.¹

4. This under-recovery is the result of higher than forecasted gas costs resulting from periods of extreme cold weather affecting much of the United States, and New England in particular, during January and February 2026, and the effect on natural gas demand and production during that time.²

5. In accordance with the Gas Cost Recovery Clause of the Gas Tariff the Company has proposed an interim adjustment of its GCR factors for effect May 1, 2026 to reduce the forecasted under-recovery as of October 31, 2026.³

6. Section 2, Schedule A, Item 1.2 of the Gas Tariff provides that, “[u]nless otherwise notified by the PUC, the Company shall submit the Gas Charge filings no later than sixty (60) days before they are scheduled to take effect.” (emphasis added.) By this motion, the Company respectfully requests that the Commission approve revised GCR factors for effect in thirty days.

7. The Commission, in PUC Order No. 21784 in Docket No. 4436 and PUC Order No. 23261 in Docket No. 4719, has previously approved interim adjustments in GCR factors on less than 60 days' notice. In Docket No. 4436, the Commission approved an interim GCR factor adjustment for effect in 45 days and approved an adjustment on 30 days' notice in Docket No.

¹ Pre-Filed Direct Testimony of Tyler G. Shields dated March 31, 2026, at 4.

² Pre-Filed Direct Testimony of James M. Stephens dated March 31, 2026, at 5, *et seq.*

³ In order to mitigate bill impacts the Company has not proposed to completely eliminate the Deferred Gas Cost Balance.

4719. In each instance, the Company explained that the expedited GCR factor adjustment would help to minimize the bill impacts of the elimination of under-recoveries over the remaining months (April through October in those instances) of the respective GCR years.

8. The interim GCR factor adjustments approved by the Commission in Docket Nos. 4436 and 4719 were required to address under-recoveries that had been caused by cold weather experienced earlier in the GCR years (December) than the cold weather that has caused the under-recovery in this GCR year (January and February). Consequently, there are fewer remaining months of this GCR year, and relatively warmer months, for the Company to recover the Deferred Gas Cost Balance that has accumulated. In order to mitigate the bill impacts of the interim adjustment of GCR factors, and to reduce the amount of interest that will accumulate on the Company's Deferred Gas Cost Balance, the Company has sought adjustment of the presently effective GCR factors as of May 1, 2026.

9. Considering the facts set forth above, and as explained in more detail in the pre-filed testimonies of James M. Stephens and Tyler G. Shields, the Company submits that good cause exists for the Commission to exercise its discretion to approve the interim adjustment of GCR factors on less than 60 days' notice.

In light of the foregoing, the Company requests that the Commission permit adjustment of the GCR factors on less than 60 days' notice as permitted under Section 2, Schedule A, Item 1.2 of the Gas Tariff.

[SIGNATURE ON NEXT PAGE]

Respectfully submitted,

**The Narragansett Electric Company
d/b/a Rhode Island Energy**

By its attorney,

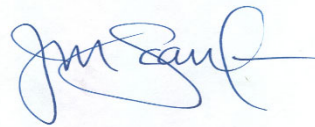


Andrew S. Marcaccio (#8168)
Rhode Island Energy
280 Melrose Street
Providence, RI 02907
(401) 784-4263

March 31, 2026

CERTIFICATE OF SERVICE

I hereby certify that on March 31, 2026, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 25-22-NG.



Joanne M. Scanlon

PRE-FILED DIRECT TESTIMONY

OF

JAMES M. STEPHENS

March 31, 2026

Table of Contents

I. Introduction..... 1

II. Change in Gas Costs 2

III. Conclusion 13

1 **I. Introduction**

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

3 A. My name is James M. Stephens. My business address is 1595 Mendon Road,
4 Cumberland, Rhode Island 02864.

5
6 **Q. Have you previously submitted testimony in this docket?**

7 A. Yes. I submitted pre-filed direct testimony on August 28, 2025 discussing The
8 Narragansett Electric Company d/b/a Rhode Island Energy (“Rhode Island Energy” or
9 the “Company”) gas supply portfolio for the 2025/26 Gas Cost Recovery (“GCR”) year
10 for which the projected gas costs and items relating to the Company’s proposed GCR
11 factors are calculated, as well as rebuttal testimony on October 10, 2025 to respond to the
12 observations and recommendations of the Division of Public Utilities and Carriers
13 (“Division”).

14
15 **Q. What is the purpose of your testimony?**

16 A. The purpose of my testimony is to discuss the Company’s gas supply portfolio and the
17 major factors that have contributed to the change in gas costs and associated deferred gas
18 cost balance discussed in the Direct Testimony of Company Witness Tyler Shields.

19

1 **II. Change in Gas Costs**

2 **Q. Have there been any notable changes to the Company’s gas supply portfolio, or the**
3 **way the Company purchases gas, since the 2025 GCR proceeding?**

4 A. No. There have been no changes to the Company’s gas supply portfolio, or the approach
5 to gas supply purchases, which were discussed in my pre-filed direct testimony filed on
6 August 28, 2025.

7
8 **Q. Why is it necessary to request an increase in the GCR factors at this time?**

9 A. The extreme cold weather experienced from late January through early February 2026
10 (“2026 Cold Snap”), and the unprecedented energy market conditions during the
11 extreme weather, have resulted in an increase in gas costs relative to the Company’s
12 projected gas costs and the associated deferred gas cost balance from its initial
13 August 28, 2025 GCR filing (“Initial GCR Filing”).

14
15 **Q. Please discuss the weather experienced during winter 2025/26 and the 2026 Cold**
16 **Snap.**

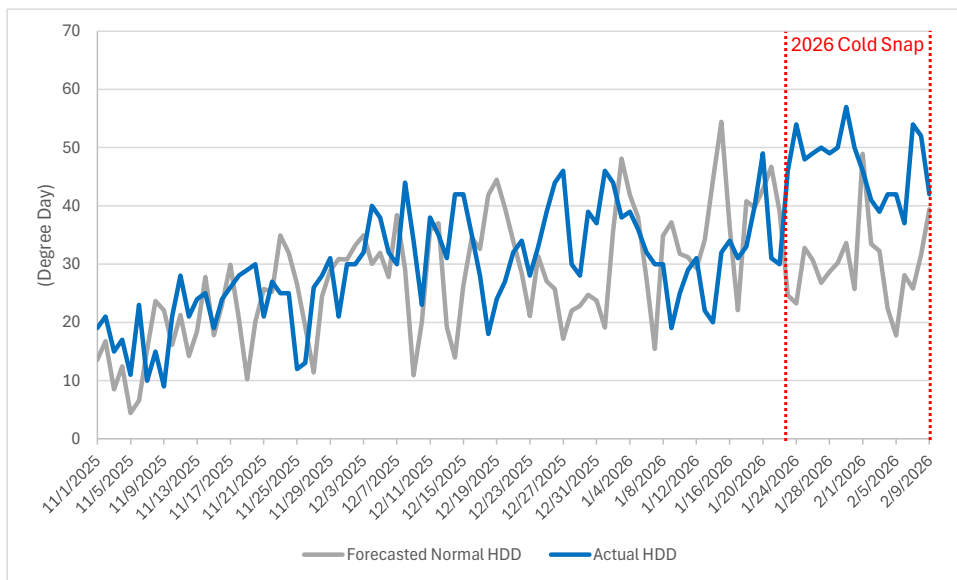
17 A. Prior to discussing the 2026 Cold Snap, it is important to note actual weather for the
18 winter-to-date (i.e., November 1, 2025 through and including February 9, 2026) has
19 been the coldest experienced by Rhode Island Energy in over 30 years. The figure
20 below illustrates the actual average daily heating degree day (“HDD”) for Providence,
21 Rhode Island for the November 1, 2025 through February 9, 2026 period compared to

1 forecasted normal weather HDDs, which shows actual daily weather has been generally
2 colder than forecasted normal weather.

3

4

Figure 1: Actual vs. Forecasted Weather – Providence



5

6

7 As shown in Figure 1 above, significantly colder-than-normal weather was experienced
8 over an extended 18-day period from January 23, 2026 through February 9, 2026 (i.e.,
9 the 2026 Cold Snap). Specifically, the 18-day period during the 2026 Cold Snap was
10 nearly 60 percent colder-than-forecasted normal weather and significantly colder than
11 recent winters.¹ There was a total of 848 HDDs during this 2026 Cold Snap, which
12 equates to an average daily HDD of 47 (or a daily average temperature of 18 degrees

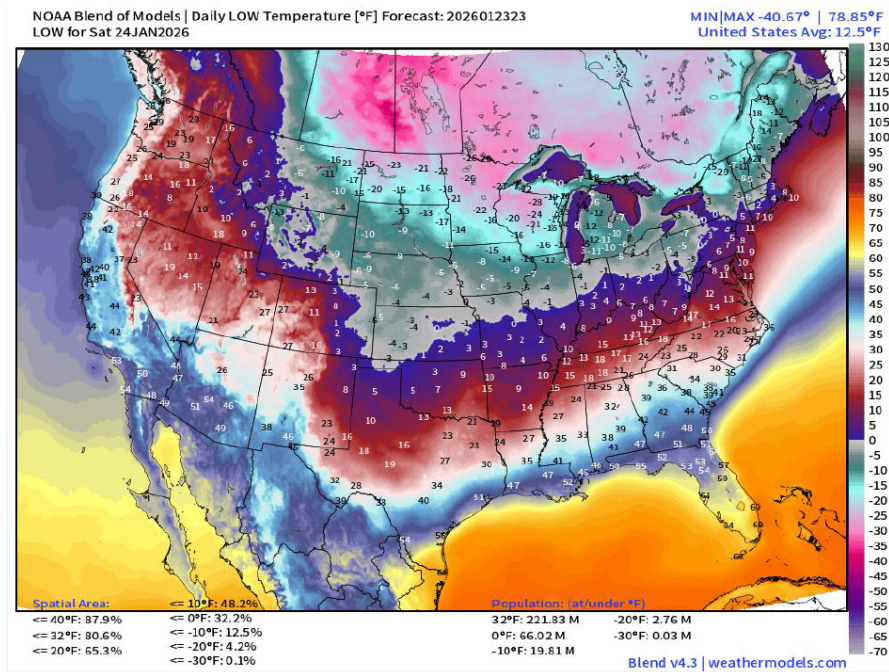
¹ Specifically, the months of January and February 2025 were approximately 3 percent colder-than-normal and the months of January and February 2024 were 7 percent warmer-than-normal.

Fahrenheit). Notably, the 2026 Cold Snap was the coldest and longest cold spell experienced by Rhode Island Energy since 2015.

Q. Was the extreme cold weather unique to Rhode Island Energy’s service territory?

A. No. Winter Storm “Fern” brought severe arctic cold weather to nearly all U.S. regions,² as well as Canada and Northern Mexico, beginning on January 23, 2026 as shown in Figure 2 below.

Figure 2: Winter Storm Fern



² Please note, this widespread winter storm was unofficially named Winter Storm Fern by The Weather Channel, and over 20 U.S. states declared state of emergencies due to the weather conditions. Source: The Weather Channel, “Winter Storm Fern: Power Outages, Thousands of Flight Cancellations, Treacherous Roads,” <https://weather.com/news/weather/news/2026-01-24-live-updates-winter-storm-fern-january-24>.

1 **Q. Please summarize the effect of Winter Storm Fern on the U.S. energy markets.**

2 A. The extreme arctic cold temperatures and winter storm conditions across most of North
3 America associated with Winter Storm Fern had a wide-scale impact on U.S. energy
4 markets, in general, and the U.S. natural gas markets, in particular. Specifically, there
5 was high electricity demand in the U.S. with natural gas as the fuel most relied on for
6 electric generation across many regions, particularly the Mid-Atlantic/PJM, New
7 York/NYISO, and New England/ISO-NE regions.³ Notably, because of the projected
8 record high electricity demand and storm- and cold-related generator outages, PJM
9 instructed generators on January 24, 2026 to secure natural gas to meet generation needs
10 through the end of January 2026 rather than normal day-ahead purchases. PJM also
11 requested (and was granted) an emergency order from the U.S. Department of Energy to
12 run all electric generating units within the PJM region, and operate up to their maximum
13 generation output levels, notwithstanding air quality or other permit limitations or fuel
14 shortages to ensure power grid reliability.^{4,5}

³ Source: American Gas Association, “Weathering Winter: A Lookback at the Natural Gas Market During Winter Storm Fern,” February 2026, <https://www.aga.org/research-policy/resource-library/a-natural-gas-industry-outlook-and-a-lookback-at-winter-storm-fern/>.

⁴ Source: PJM Interconnection, L.L.C., “Request for Emergency Order Under Federal Power Act, Section 202(c),” January 24, 2026, <https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection-pjm-order-no-202-26-02>.

⁵ Please note, the U.S. Department of Energy also issued emergency orders to the NYISO and ISO-NE for relief during Winter Storm Fern to ensure reliability. Source: <https://www.energy.gov/ceser/2026-doe-202c-orders>.

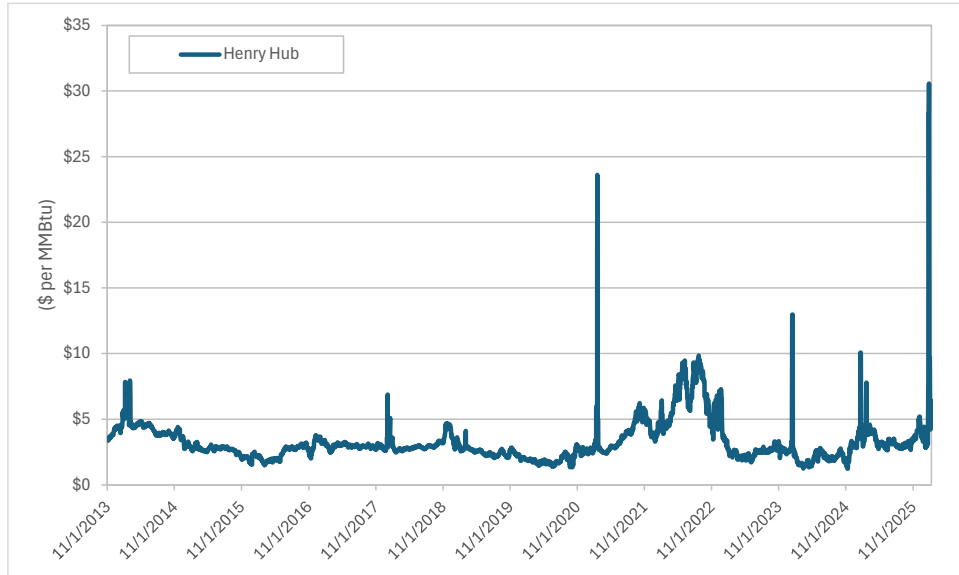
1 Overall U.S. demand for natural gas spiked to 173 million dekatherms (“Dth”) on
2 January 24, 2026 and remained well above the five-year average for the next ten days.⁶
3 At the same time, natural gas production decreased due to equipment freeze-offs and
4 shut-ins, particularly in the oil-producing regions (e.g., Permian Basin), with the largest
5 overall production decline occurring on January 26, 2026.⁷ The significant increase in
6 natural gas demand for heating and power generation, coupled with the gas supply
7 constraints, contributed to a significant spike in natural gas commodity prices at many
8 locations throughout the U.S. to unprecedented levels on January 27, 2026. For example,
9 Henry Hub (i.e., the primary benchmark for North American gas prices) spiked to a new
10 record high of over \$30 per million British thermal units (“MMBtu”) as shown in Figure
11 3 below.
12

⁶ Source: American Gas Association, “Weathering Winter: A Lookback at the Natural Gas Market During Winter Storm Fern,” February 2026, <https://www.aga.org/research-policy/resource-library/a-natural-gas-industry-outlook-and-a-lookback-at-winter-storm-fern/>.

⁷ Source: Wood Mackenzie, “Winter Storm Fern shuts in 18.3 bcf of US gas production at its peak,” February 5, 2026, <https://www.woodmac.com/news/opinion/wss-winter-storm-fern-shuts-in-18.3-bcf-of-us-gas-production-at-its-peak>.

1

Figure 3: Daily Spot Prices – Henry Hub



2

3

4

5

6

7

8

9

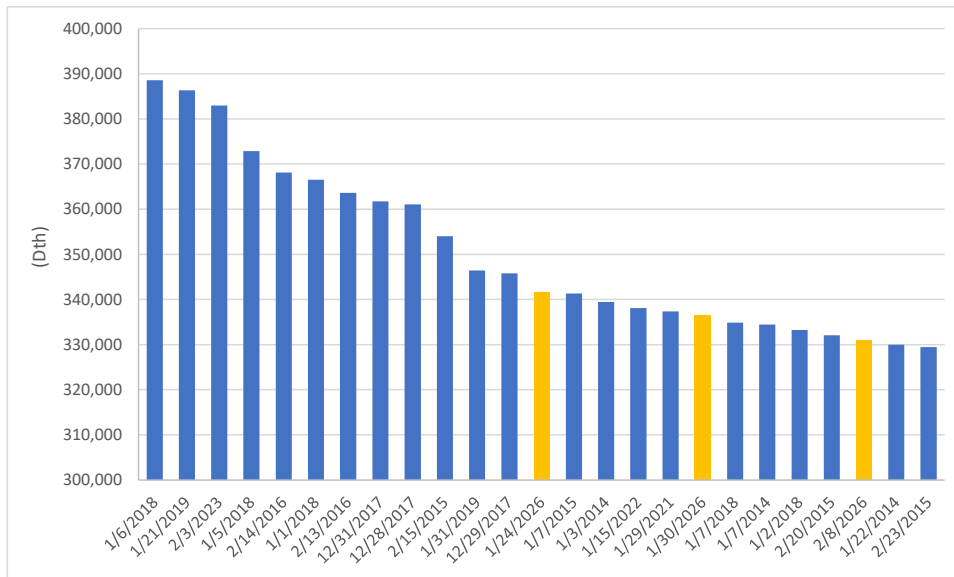
The sustained severe cold weather continued to affect many U.S. regions for the days thereafter, with significant increases in gas imports from Canada and record high gas storage withdrawals for the week ending January 30, 2026,⁸ and spot gas prices decreasing from the record peak levels experienced on January 27, 2026 but remaining elevated above prior peaks (see, also, Figures 5 through 8 below).

⁸ Sources: U.S. Energy Information Administration, “Today in Energy: Record natural gas stock withdrawals during week ending January 30, 2026,” <https://www.eia.gov/todayinenergy/detail.php?id=67124>; and American Gas Association, “Natural Gas Market Indicators – February 5, 2026,” <https://www.aga.org/research-policy/resource-library/natural-gas-market-indicators-502nd-edition/>.

1 **Q. How did the extreme cold weather affect Rhode Island Energy’s customer demand**
 2 **for natural gas?**

3 A. The severe cold weather resulted in an increase in natural gas usage, with total customer
 4 demand exceeding 5.3 million Dth over the 18-day period of the 2026 Cold Snap.⁹
 5 During this 2026 Cold Snap, Rhode Island Energy also experienced three of the highest
 6 natural gas demand days in the Company’s history. The figure below illustrates the
 7 Company’s top 25 sendout days with the three new 2026 observations
 8 highlighted in yellow.¹⁰

Figure 4: Top 25 Sendout Days



11

⁹ Please note, the Company issued a system-wide non-firm customer curtailment for the duration of the 2026 Cold Snap.

¹⁰ Please note, the three new 2026 observations occurred on a Saturday (January 24), Friday (January 30), and Sunday (February 8).

1 **Q. How did the Company’s gas supply portfolio perform during the 2026 Cold Snap?**

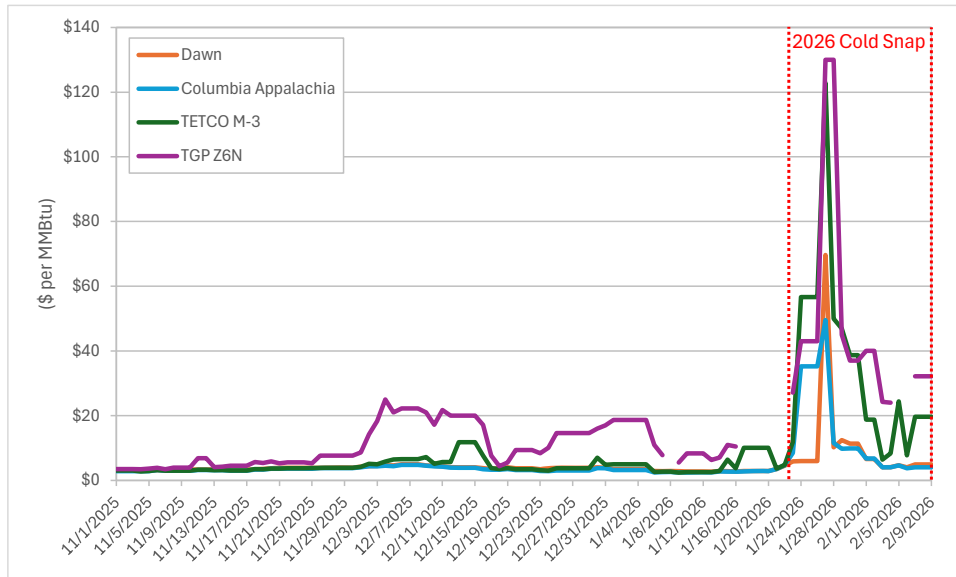
2 A. Because of high customer demand during the 2026 Cold Snap, Rhode Island Energy
3 relied on its entire portfolio of gas supply, pipeline transportation, underground storage,
4 and peaking resources, including the Company’s portable liquefied natural gas (“LNG”)
5 assets. All assets in the Company’s portfolio performed exceptionally well.
6 Specifically, all gas supply counterparties met their obligations and all upstream
7 pipelines performed well, with Algonquin Gas Transmission, LLC (“AGT”) and
8 Tennessee Gas Pipeline Company, L.L.C. (“TGP”) operating under tight hourly and
9 daily balancing tolerances. All LNG assets were dispatched and were critical in meeting
10 peak hourly demand, managing AGT/TGP pipeline balancing requirements, and
11 augmenting pressure fluctuations from the pipelines. As a result, there were no gas
12 supply or service interruptions to the Company’s customers during the 2026 Cold Snap.

13
14 **Q. How did the 2026 Cold Snap affect the Company’s actual gas costs?**

15 A. Rhode Island Energy faced the same unprecedented market conditions that were present
16 across most of North America discussed above. Specifically, actual gas costs incurred by
17 the Company were significantly higher because natural gas commodity prices across all
18 locations at which the Company purchased gas supplies reached unprecedented price
19 levels and certain price indices remained elevated during the 2026 Cold Snap. The figure
20 below illustrates the daily spot prices from November 1, 2025 through February 9, 2026
21 for certain price indices at which the Company purchased gas supplies.

1

Figure 5: Daily Spot Prices – Winter 2025/2026



2

3

4

As illustrated in Figure 5 above, gas prices spiked during the 2026 Cold Snap and

5

reached new record peaks on January 27, 2026. For example, gas prices in the

6

Appalachian region (i.e., Marcellus shale production area) increased as much as ten-fold

7

from historical peak levels, with the Columbia Appalachia price index peaking at

8

approximately \$50 per MMBtu and Transco Leidy price index reaching nearly \$96 per

9

MMBtu. Notably, the gas prices in the Appalachian region remained at high price levels

10

during the 2026 Cold Snap; for example, five of the ten highest Columbia Appalachia

11

price observations since November 1, 2013 occurred during the 2026 Cold Snap.

12

Historical daily spot prices for certain price indices in the Appalachian region from

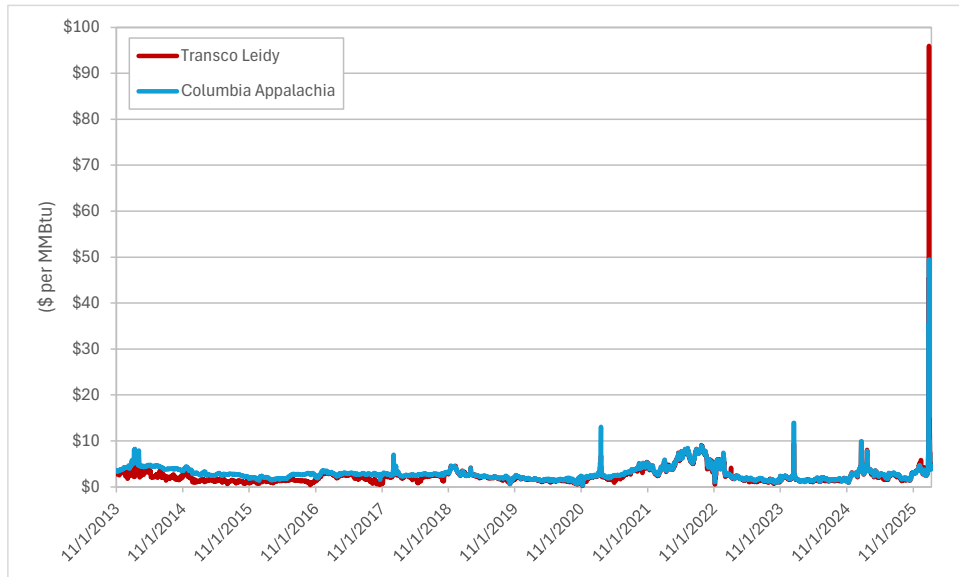
13

November 1, 2013 through February 9, 2026 are shown in Figure 6 below.

14

1

Figure 6: Daily Spot Prices – Appalachian Region



2

3

4

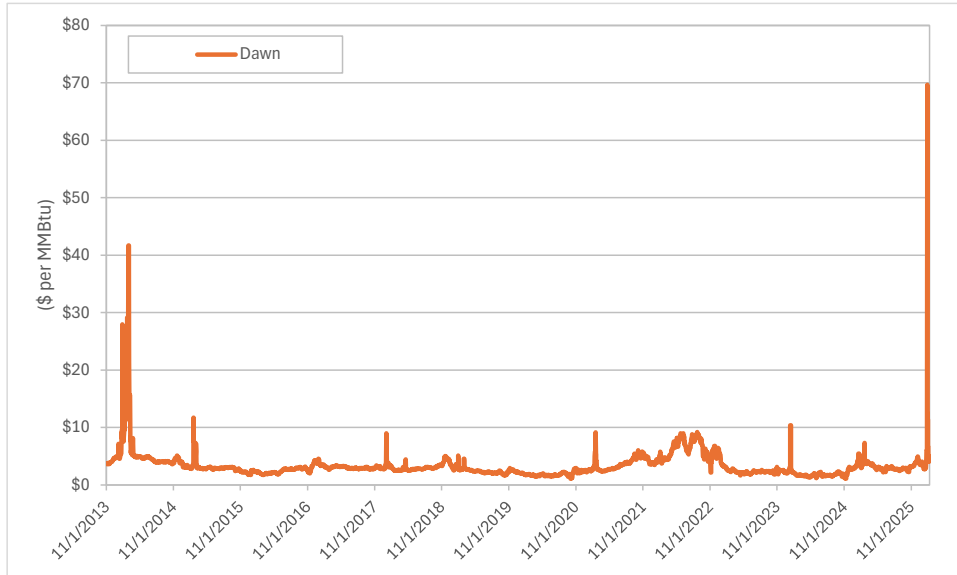
In addition, Canadian gas supplies priced at the Dawn price index peaked at nearly \$70 per MMBtu on January 27, 2026, which is approximately 67 percent higher than the prior peak of \$42 per MMBtu experienced in March 2014. Historical daily Dawn prices over the November 1, 2013 to February 9, 2026 period are shown in Figure 7 below.

7

8

1

Figure 7: Daily Spot Prices – Dawn, Ontario



2

3

4

5

6

7

8

9

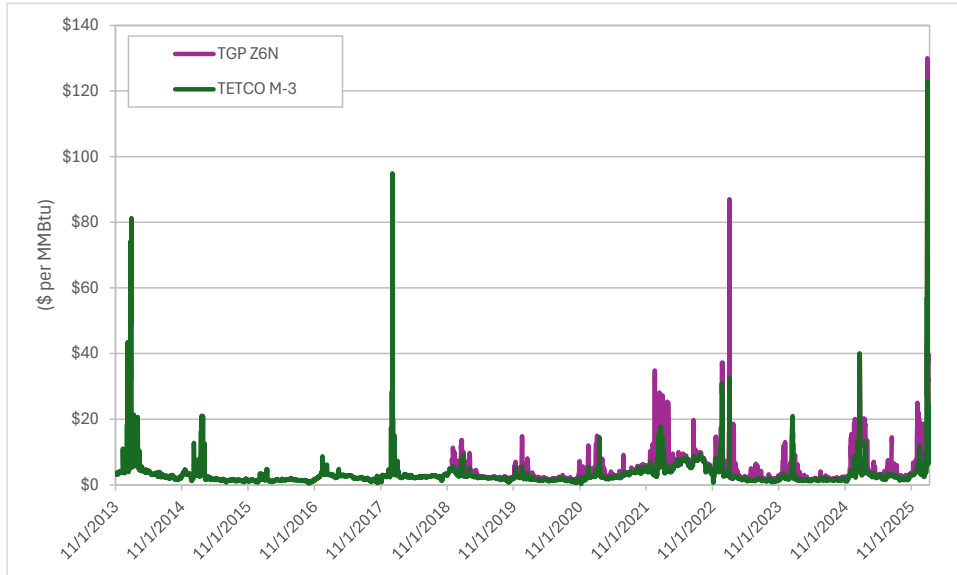
10

11

Finally, the New York and New England regional prices also increased from prior historical peak levels. For example, as shown in Figure 8 below, the TETCO M-3 price index was over \$120 per MMBtu and the TGP Zone 6 North price index reached a new peak of \$130 per MMBtu on January 27, 2026. In addition, five of the ten highest TETCO M-3 price observations since November 1, 2013 occurred during the 2026 Cold Snap; and eight of the ten highest TGP Zone 6 North price observations since November 1, 2013 occurred during the 2026 Cold Snap.

1

Figure 8: Daily Spot Prices – New York and New England



2

3

4

In summary, natural gas commodity prices at which Rhode Island Energy purchased gas supplies reached unprecedented levels during the 2026 Cold Snap. The extended cold spell resulted in actual gas costs incurred by the Company well above the projected gas costs from the Initial GCR Filing, as shown in Mr. Shields' testimony.

8

9 **III. Conclusion**

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

11 **A. Yes.**

PRE-FILED DIRECT TESTIMONY

OF

TYLER G. SHIELDS

March 31, 2026

Table of Contents

I. Introduction..... 1

II. Purpose and Organization of Testimony 1

III. GCR Factor Development..... 3

IV. Bill Impacts..... 12

V. Conclusion 13

1 **I. Introduction**

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

3 A. My name is Tyler G. Shields, and my business address is 280 Melrose Street, Providence,
4 Rhode Island 02907.

5

6 **Q. Have you previously submitted testimony in this docket?**

7 A. Yes. On August 28, 2025, I submitted pre-filed direct testimony in this docket
8 concerning The Narragansett Electric Company d/b/a Rhode Island Energy's ("Rhode
9 Island Energy" or "the Company") Gas Cost Recovery ("GCR") filing. My August 28,
10 2025 testimony presented the Company's proposed rate design, proposed GCR factors,
11 and resulting bill impacts based on the proposed factors, pursuant to the Company's Gas
12 Cost Recovery Clause in RIPUC RIE-GAS No. 101 ("the Tariff"). The Public Utilities
13 Commission ("PUC") approved the currently effective GCR factors presented in the
14 Corrected GCR filing submitted on September 16, 2025 following the conclusion of the
15 hearing in this docket on October 27, 2025.

16

17 **II. Purpose and Organization of Testimony**

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

19 A. The purpose of my testimony is to propose revised GCR factors for effect May 1, 2026
20 for the following services: firm sales service to customers in the Residential Non-Heating
21 and Heating rate classes and firm sales customers in the Small, Medium, Large, and

1 Extra-Large Commercial and Industrial (“C&I”) rate classes. I will also discuss the
2 reasons for the Company’s interim GCR filing.

3
4 **Q. How is your testimony organized?**

5 A. Section I of my testimony is an introduction that includes my background and
6 qualifications. Section II explains the purpose and organization of my testimony. Section
7 III describes the development of the Company’s proposed interim GCR factor. Section
8 IV presents the impacts of its proposed rates for effect May 1, 2026, on customer bills.
9 Section V is the conclusion.

10
11 **Q. Who is supporting the Company’s request in this filing?**

12 A. Accompanying my testimony, which supports the calculation of the requested increase in
13 the Company’s GCR factors and resulting bill impacts, the Company is also presenting
14 the testimony of Company Witness James M. Stephens, Director of Gas Procurement and
15 Gas Control, who discusses the Company’s gas supply portfolio and the major factors
16 that have contributed to the change in gas costs and its associated effect on the deferred
17 gas cost balance.

18
19 **Q. Are you sponsoring any attachments to your testimony?**

20 A. Yes. I am sponsoring the following attachments to my testimony:

21 Attachment TGS-1 Proposed Gas Cost Recovery Factors

1		
2	Attachment TGS-2	Estimated Deferred Gas Cost Balance without
3		Revised GCR
4		
5	Attachment TGS-3	Estimated Deferred Gas Cost Balance with
6		Revised GCR
7		
8	Attachment TGS-4	Bill Impact Analysis
9		

10 **III. GCR Factor Development**

11 **Q. What are the revised GCR factors the Company is proposing?**

12 A. The Company is requesting approval to increase the current High Load and Low Load
13 GCR factors by \$0.325 per therm (\$0.3313 per therm including the gross up for
14 uncollectible). Attachment TGS-1 provides a summary of the proposed GCR factors
15 reflecting this increase, proposed for effect May 1, 2026.

17 **Q. Why is the Company proposing revision of its currently approved GCR factors?**

18 A. The Company is proposing revision of its current GCR factors to recover a portion of the
19 projected deferred gas cost balance at the end of October 2026. According to the
20 Company's Tariff, RIPUC RIE-Gas No. 101, Section 2, Schedule A, Part 1.2, "[i]n the
21 event of any change subsequent to the November effective date which would cause the
22 estimate of the Deferred Gas Cost Balance to differ from zero by an amount greater than
23 five percent (5%) of the Company's gas revenues, the Company may make a Gas Charge
24 filing designed to eliminate that non-zero balance." Currently, the Company is projecting

1 the deferred gas cost balance at October 31, 2026 to be approximately 14.1 percent of the
2 total annual gas cost revenue. The Company is proposing to increase its current GCR
3 factors at this time because of the size of the estimated deferral balance and the impact
4 that could have on customers' bills for the 2026/27 winter if the balance is not reduced at
5 this time.

6
7 The table below reflects the month-to-month change in the Projected GCR Deferred Gas
8 cost balance with the initial projected balance reflected in the Company's GCR Filing
9 submitted to the PUC on September 16, 2025, in Docket No. 25-22-NG in Column (a).

		(a)	(b)	(c)	(d)	(e)
		Docket No. 25-22-NG Annual GCR Filing	November 2025	December 2025	January 2026	February 2026
(1)	Projected Ending Balance with Interest (Over)/under	(\$309,806)	\$3,208,069	\$2,964,414	\$27,164,016	\$25,775,273
(2)	Month-to-Month Change	-	\$3,517,876	(\$243,655)	\$24,199,602	(\$1,388,743)
(3)	Deferred Balance to Annual GCR Revenues %	-	1.9%	1.7%	15.4%	14.1%

10
11 **Q. What is the projected deferred gas cost balance at the end of October 2026 if the**
12 **Company does not change the GCR factors?**

13 A. If the Company does not increase its currently approved GCR factors, the Company is
14 projecting a deferred gas cost balance of approximately \$25.8 million at the end of October

1 2026, as detailed in Attachment TGS-2. The \$25.8 million projected gas cost deferral reflects
2 actual gas costs for the months of November 2025 through February 2026 and an updated
3 forecast for the period March 2026 through October 2026.

4
5 **Q. What is the major factor contributing to this projected deferred gas cost balance?**

6 A. As discussed in Mr. Stephens' testimony, significantly colder than normal weather,
7 higher demand, and higher natural gas prices resulted in increases in actual gas costs
8 during the period January 2026 through February 2026 as compared to the forecast of gas
9 costs presented in the Company's Corrected GCR filing which was a major factor
10 contributing to this projected deferred gas cost balance.

11
12 **Q. Are the proposed GCR factors designed to eliminate the projected deferred balance
13 by October 31, 2026?**

14 A. No, the Company is not proposing to revise its current GCR factors to eliminate the
15 deferred balance by October 31, 2026. The Company is proposing to increase its GCR
16 factors by a factor that is designed to recover approximately \$17.1 million of the deferral
17 during the period May 2026 through October 2026 and is proposing to delay recovery of
18 approximately \$8.7 million of the projected deferred balance into the period November
19 2026 through October 2027. In evaluating the recovery of the \$25.8 million projected
20 deferral during the period May 2026 through October 2026, the Company balanced
21 recovery with resulting bill impacts. The bill impact of a full recovery of the projected

1 deferral on a Residential Heating customer would be a 22.1 percent total bill increase
2 over the period May 2026 through October 2026 as compared to currently effective
3 factors. Based on the impact not only to the Company's Residential Heating customers,
4 but also the impact that this level of recovery would have on all of its customers coming
5 out of a challenging winter season, the Company determined that a bill mitigation plan is
6 appropriate to phase in recovery of the projected deferral. This balanced approach is
7 designed to provide for more manageable bill increases resulting from the rate change
8 proposed in this filing while tempering the effect of the existing deferred balance on GCR
9 factors that will be proposed for effect November 1, 2026 in the Company's next annual
10 GCR filing. In considering these factors, the Company arrived at the proposal reflected
11 in this filing, which results from limiting the total bill increase to a Residential Heating
12 customer who uses 845 therms annually to 14.8 percent, and further results in deferring
13 recovery of approximately \$8.7 million of the \$25.8 million deferred balance to 2026-27.

14
15 **Q. Has the PUC approved a similar request for an interim change in the Company's**
16 **GCR factors in the past?**

17 A. Yes, the Company is aware of two instances. Please see PUC Order No. 21784 in Docket
18 No. 4436 (issued 2014) and PUC Order No. 23261 in Docket No. 4719 (issued 2018).

19
20 First, on April 1, 2014, the Company increased its Low Load and High Load GCR Factors
21 approved for November 1, 2013 in Docket No. 4436 from \$0.6626 per therm and \$0.6381

1 per therm, respectively, to \$0.9208 per therm and \$0.8963 per therm, respectively. This
2 resulted in an increase in the GCR factors of \$0.2582 per therm (\$0.2500 per them before
3 the adjustment to gross up the factor for uncollectibles) and a 16.3 percent total bill
4 increase for a Residential Heating customer during the months of April 2014 through
5 October 2014. In addition, this proposed increase recovered approximately 50 percent of
6 the projected deferred balance of \$34.5 million, thereby deferring recovery of
7 approximately \$16.9 million to be recovered from customers during the following GCR
8 period of November 2014 through October 2015.

9
10 On March 1, 2018, the Company increased its Low Load and High Load GCR Factors
11 approved for November 1, 2017 in Docket No. 4719 from \$0.5291 per therm and \$0.4859
12 per therm, respectively, to \$0.7614 per therm and \$0.7183 per therm, respectively. This
13 resulted in an increase in the GCR factors of \$0.2324 per therm (\$0.2250 per them before
14 the adjustment to gross up the factor for uncollectibles) and a 15.6 percent total bill
15 increase for a Residential Heating customer during the months of March 2018 through
16 October 2018. In addition, this proposed increase recovered approximately 20 percent of
17 the projected deferred balance of \$34.4 million, thereby deferring recovery of
18 approximately \$27.4 million to be recovered from customers during the following GCR
19 period of November 2018 through October 2019.¹

¹ Per Docket No. 4719, October 2018's Deferred Monthly Report

1 **Q. Is the Company’s proposal consistent with the interim GCR factors approved in**
2 **Docket No. 4436 and Docket No. 4719?**

3 A. Yes, the Company’s proposal will result in a 14.8 percent total bill increase for
4 Residential Heating customers using 845 therms annually, which is similar to the bill
5 increase approved in Docket No. 4436 of 16.3 percent and Docket No. 4719 of 15.6
6 percent. This is consistent with the preceding proposals in that it seeks to recover a
7 portion of the projected deferred gas cost balance, balancing the priorities of immediate
8 bill impacts and customer interest on high deferred gas cost balances.

9
10 **Q. Please provide an overview of the development of the proposed revised GCR rates.**

11 A. The Company has calculated the proposed increase in the current GCR factors by
12 determining a surcharge with the objectives of setting a simple value for the surcharge
13 and limiting the total bill increase for a Residential Heating customer using 845 therms
14 annually to below 16 percent during the period May 2026 through October 2026. This
15 results in a surcharge of \$0.3250 per therm (\$0.3313 per therm after the adjustment for the
16 gross up for uncollectibles).

17
18 **Q. What is the impact of the revised GCR factors on the projected deferred balance at**
19 **October 31, 2026?**

20 A. With the implementation of the revised GCR factors proposed in this filing effective
21 May 1, 2026, the Company projects a gas cost deferred balance of approximately

1 \$8.7 million at the end of October 2026, as detailed in Attachment TGS-3. The Company
2 will propose to recover the final deferred gas cost balance in its 2026-27 GCR factors that
3 will be proposed by the Company on or before September 1, 2026.

4
5 **Q. Why can the Company not carry the deferred gas costs and recover them during the**
6 **following GCR period of November 2026 through October 2027?**

7 A. According to the Company's Gas Cost Recovery Clause in its Tariff,² in the event the
8 estimate of the Deferred Gas Cost balance differs by more than five percent of the
9 Company's gas revenues, the Company may make a Gas Charge filing designed to
10 eliminate the balance. The provision is intended to (1) not burden the sales customers with
11 significant deferred gas costs that they would need to pay for in a subsequent year, with
12 significant defined as five percent of gas cost revenue for the year; and (2) recover the
13 incremental gas costs from those customers who benefited from the gas supply services
14 resulting in the increase and not defer recovery to future customers. The projected
15 deferral consists predominantly of actual costs, which the Company has and will have to
16 pay to its suppliers.

² See RIPUC RIE-GAS No. 101, Section 2, Gas Charge, Schedule A, Sheet 1, Part 1.2.

1 In addition, if the Company does not recover some of the projected deferral, sales
2 customers will eventually have to pay for the interest cost of the Company carrying the
3 deferral at the Bank of America prime rate less 200 basis points, pursuant to the Tariff.³
4

5 **Q. How much interest cost will customers avoid by an increase in the GCR factors on**
6 **May 1, 2026?**

7 A. The Company estimates that customers will avoid approximately \$236,000 in interest
8 through October 31, 2026. While the Company has not estimated the benefit, customers
9 will also benefit from avoiding interest in the following GCR period, as the beginning
10 balance of the deferral will be significantly less under the Company's proposal, resulting
11 in less interest accruing on that beginning balance as of November 2026.
12

13 **Q. Did the Company evaluate other options for setting the surcharge to increase the**
14 **current GCR factors besides the two discussed earlier in your testimony?**

15 A. In determining the appropriate adjustment to the current GCR factors, the Company also
16 considered carrying the entire deferred balance to be collected in the 2026-27 GCR year.
17 As stated earlier in my testimony, this would create a significant burden on sales
18 customers for the 2026-27 GCR year on its own, but given the uncertainty of future gas

³ See RIPUC RIE-GAS No. 101, Section 2, Gas Charge, Schedule A, Part 6.3.

1 costs, as well as future unpredictable weather the Company believes it more reasonable to
2 recover a portion of the deferral in the period of May through October 2026.

3
4 **Q. Why is the Company asking for a GCR rate change effective May 1, 2026?**

5 A. The process for requesting a change in gas charges requires 60 days' notice unless
6 otherwise permitted by the PUC. The Company is requesting that the PUC approve a
7 change in the GCR factors on 30 days' notice, effective May 1, 2026, to recover the
8 portion of the deferral over a six-month period. Delaying the implementation of the
9 proposed GCR factors until June 1, 2026 would result in fewer gas deliveries over which
10 any portion of the projected deferral could be recovered, which would result in higher
11 GCR factors and resulting bill impacts.

12
13 **Q. Are other New England gas distribution companies requesting increases in their
14 commodity factors?**

15 A. Yes. Eight Massachusetts gas utilities requested and received approval for increases in
16 their previously approved Peak Gas Adjustment ("GAFs")⁴ effective March 1, 2026⁵
17 resulting from increases in gas costs during this period. The table below summarizes for

⁴ Massachusetts gas utilities implement Peak (November through April) and Off-Peak (May through October) GAFs.

⁵ Massachusetts gas utilities must submit for approval by the Department of Public Utilities revisions to their GAF's seven business days prior to their proposed effective date.

1 each Massachusetts gas utility the increase in its Peak GAF and the associated bill
2 impacts on its residential heating customers.⁶

		February 1, Peak GAF \$/therm	March 1, Peak GAF \$/therm	Increase in Factor	Percent Increase	Bill Impact
		(a)	(b)	(c)	(d)	(e)
(1)	Berkshire Gas	\$0.6561	\$0.9641	\$0.3080	46.94%	20.74%
(2)	Eversource Gas Company of Massachusetts	\$0.9832	\$1.3603	\$0.3771	38.35%	15.68%
(3)	Fitchburg Gas d/b/a Unutil	\$0.7121	\$1.2454	\$0.5333	74.89%	17.30%
(4)	Liberty Utilities - Blackstone	\$0.8818	\$1.8834	\$1.0016	113.59%	63.54%
(5)	Liberty Utilities - North Attleboro/Fall River	\$0.6283	\$1.2505	\$0.6222	99.03%	36.59%
(6)	National Grid - Boston Gas	\$0.9564	\$1.2329	\$0.2765	28.91%	10.87%
(7)	National Grid - Colonial Gas	\$0.9564	\$1.2329	\$0.2765	28.91%	11.49%
(8)	NSTAR Gas Company d/b/a Eversource Energy	\$0.9477	\$1.2269	\$0.2792	29.46%	10.94%

3

4 **IV. Bill Impacts**

5 **Q. What is the bill impact of the proposed GCR factors on customer bills as compared**
6 **to the rates currently in effect?**

7 A. An average residential heating customer using 160 therms for the period May through
8 October will experience a total bill increase of \$54.64 or 14.8 percent, over their bills at
9 currently effective rates. A summary of seasonal (May through October) bill impacts
10 incorporating only the proposed change in the GCR factors for rate classes at various
11 levels of usage is provided in Attachment TGS-4.

12

⁶ Bill impact is based on the respective utilities' sample bills and rates in effect using 160 therms over the period May through October 2026, excludes taxes.

V. **Conclusion**

1 Q. Does this conclude your testimony?

2 A. Yes.

Attachments of Tyler G. Shields

Attachment TGS-1	Proposed Gas Cost Recovery Factors
Attachment TGS-2	Estimated Deferred Gas Cost Balance without Revised GCR
Attachment TGS-3	Estimated Deferred Gas Cost Balance with Revised GCR
Attachment TGS-4	Bill Impact Analysis

Attachment TGS-1

Proposed Gas Cost Recovery Factors

**The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Factors Effective May 1, 2026**

<u>Description</u> (a)	<u>Source</u>		<u>High Load</u> ¹ (c)	<u>Low Load</u> ² (d)
	<u>Reference</u> (b)			
(1) Fixed Cost Factor - \$/dktherm	Approved Factor*		\$1.4718	\$2.0276
(2) Variable Cost Factor -\$/dktherm	Approved Factor		\$4.1935	\$4.1935
(3) Total Gas Cost Recovery Charge- \$/dktherm	(1) + (2)		\$5.6653	\$6.2212
(4) GCR Incremental Surcharge Factor	Manual Input		\$3.2500	\$3.2500
(5) Total Revised Gas Cost Recovery Charge- \$/dktherm	(3) + (4)		\$8.9153	\$9.4712
(6) Uncollectible %	Docket No. 4770		1.91%	1.91%
(7) Total GCR Charge adjusted for Uncollectibles- \$/dktherm	(5) ÷ [1 - (4)]		\$9.0889	\$9.6556
(8) GCR Charge on a per therm basis	(5) ÷ 10		\$0.9088	\$0.9655
(9) Current rate effective 11/01/25 - \$/therm	Docket No. 25-22-NG		\$0.5775	\$0.6342
(10) Increase / (Decrease) - \$/therm	(8) - (9)		\$0.3313	\$0.3313
(11) Percent Increase	(10) ÷ (9)		57.4%	52.2%

* GCR rates approved in GCR Filing per Docket No. 25-22-NG (Corrected) filed on September 16, 2025

¹ Includes: Residential Non Heating, Large High Load and Extra Large High Load

² Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load

(8): Truncated to 4 decimals.

Attachment TGS-2

Estimated Deferred Gas Cost Balance without
Revised GCR

Deferred Gas Cost Balances

	Description	Reference	Nov Actual 30 (a)	Dec Actual 31 (b)	Jan Actual (c)	Feb Actual 28 (d)	Mar Forecast 31 (e)	Apr Forecast 30 (f)	May Forecast 31 (g)	Jun Forecast 30 (h)	Jul Forecast 31 (i)	Aug Forecast 31 (j)	Sep Forecast 30 (k)	Oct Forecast 31 (l)	Nov-Oct 365 (m)
(1)	# of Days in Month														
(2)	I. Fixed Cost Deferred														
(3)	Beginning Under/(Over) Recovery		(\$13,924,066)	(\$12,367,836)	(\$19,607,999)	(\$25,222,803)	(\$31,228,960)	(\$34,311,175)	(\$35,060,344)	(\$32,879,904)	(\$29,291,335)	(\$25,184,407)	(\$20,907,508)	(\$16,684,216)	(\$13,924,066)
(4)	Supply Fixed Costs (net of cap rel)	Sch. 2, line (31)	\$8,117,432	\$7,560,197	\$8,368,573	\$8,387,193	\$9,509,862	\$7,399,845	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$93,477,014
(5)	Supply Related System Pressure to DAC		(\$986,458)	(\$1,168,288)	(\$1,266,121)	(\$1,251,721)	(\$2,231,165)	(\$226,605)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$8,335,493)
(6)	Supply Related LNG O & M		\$192,721	\$148,662	\$79,300	\$60,893	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$1,034,791
(7)	NGPMP Credits	Dkt 4770	(\$1,507,649)	(\$6,076,656)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$22,660,798)
(8)	Working Capital	Sch. 4, line (14)	\$51,628	\$46,272	\$51,422	\$51,661	\$52,698	\$51,891	\$51,808	\$51,808	\$51,808	\$51,808	\$51,808	\$51,808	\$616,425
(9)	Total Supply Fixed Costs	Sum(4)-(8)	\$5,867,674	\$510,193	\$5,725,525	\$5,740,377	\$5,892,898	\$5,780,634	\$5,769,107	\$5,769,107	\$5,769,107	\$5,769,107	\$5,769,107	\$5,769,107	\$64,131,939
(10)	Supply Fixed - Revenue	Sch. 3, line (10)	\$4,257,530	\$7,684,896	\$11,250,081	\$11,643,870	\$8,843,176	\$6,394,650	\$3,451,898	\$2,059,413	\$1,552,515	\$1,399,422	\$1,472,576	\$1,846,637	\$61,856,665
(11)	Monthly Under/(Over) Recovery	(9) - (10)	\$1,610,144	(\$7,174,704)	(\$5,524,557)	(\$5,903,493)	(\$2,950,279)	(\$614,016)	\$2,317,209	\$3,709,694	\$4,216,591	\$4,369,685	\$4,296,531	\$3,922,470	\$2,275,274
(12)	Prelim. Ending Under/(Over) Recovery	(3) + (11)	(\$12,313,922)	(\$19,542,539)	(\$25,132,556)	(\$31,126,296)	(\$34,179,239)	(\$34,925,191)	(\$32,743,136)	(\$29,170,210)	(\$25,074,744)	(\$20,814,723)	(\$16,610,977)	(\$12,761,746)	(\$11,648,791)
(13)	Month's Average Balance	[(3) + (12)] ÷ 2	(\$13,118,994)	(\$19,955,187)	(\$22,370,277)	(\$28,174,550)	(\$32,704,099)	(\$34,618,183)	(\$33,901,740)	(\$31,025,057)	(\$27,183,040)	(\$22,999,565)	(\$18,759,243)	(\$14,722,981)	(\$11,648,791)
(14)	Interest Rate (BOA Prime minus 200 bps)		5.00%	4.83%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	
(15)	Interest Applied	[(13) x (14)] - 365 x (1)	(\$53,914)	(\$65,460)	(\$90,247)	(\$102,663)	(\$131,936)	(\$135,153)	(\$136,768)	(\$121,125)	(\$109,663)	(\$92,786)	(\$73,238)	(\$59,396)	(\$1,721,350)
(16)	FIXED ENDING UNDER/(OVER) RECOVERY	(12) + (15)	(\$12,367,836)	(\$19,607,999)	(\$25,222,803)	(\$31,228,960)	(\$34,311,175)	(\$35,060,344)	(\$32,879,904)	(\$29,291,335)	(\$25,184,407)	(\$20,907,508)	(\$16,684,216)	(\$12,821,142)	(\$12,821,142)
(17)	II. Variable Cost Deferred														
(18)	Beginning Under/(Over) Recovery		\$11,777,674	\$15,178,748	\$22,117,054	\$52,497,527	\$55,627,630	\$50,690,150	\$43,983,962	\$40,945,000	\$39,553,796	\$38,821,655	\$38,574,808	\$38,129,999	\$11,777,674
(19)	Variable Supply Costs	Sch. 2, line (70)	\$10,283,052	\$21,868,143	\$51,429,463	\$26,483,952	\$12,561,155	\$5,793,537	\$3,777,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180	\$143,060,989
(20)	Supply Related System Pressure to DAC														\$0
(21)	Supply Related LNG O & M	Dkt 4770	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$302,244
(22)	Inventory Financing - LNG	Sch. 5, line (22)	\$44,779	\$43,049	\$26,870	\$19,064	\$16,018	\$17,039	\$20,701	\$21,392	\$22,273	\$23,208	\$23,963	\$27,777	\$306,131
(23)	Inventory Financing - UG	Sch. 5, line (12)	\$86,452	\$73,062	\$56,023	\$44,543	\$49,568	\$50,762	\$60,634	\$63,870	\$63,904	\$63,904	\$70,000	\$81,497	\$764,220
(24)	Working Capital	Sch. 4, line (28)	\$74,449	\$158,325	\$372,349	\$191,744	\$90,943	\$41,945	\$24,455	\$15,614	\$12,737	\$13,918	\$13,637	\$25,645	\$1,035,762
(25)	Total Supply Variable Costs	Sum(19)-(24)	\$10,513,918	\$22,167,766	\$51,909,893	\$26,764,490	\$12,742,870	\$5,928,471	\$3,508,688	\$2,282,687	\$1,883,363	\$2,048,537	\$2,016,375	\$3,702,286	\$145,469,346
(26)	Supply Variable - Revenue	Sch. 3, line (23)	\$7,186,482	\$15,305,811	\$21,679,624	\$23,831,025	\$17,894,374	\$12,819,108	\$6,718,618	\$3,830,723	\$2,773,278	\$2,451,188	\$2,610,625	\$3,390,325	\$120,491,180
(27)	Monthly Under/(Over) Recovery	(25) - (26)	\$3,327,437	\$6,861,956	\$30,230,269	\$2,933,466	(\$5,151,504)	(\$6,890,637)	(\$3,209,929)	(\$1,548,036)	(\$889,916)	(\$594,249)	(\$399,752)	\$311,961	\$24,978,165
(28)	Prelim. Ending Under/(Over) Recovery	(18) + (27)	\$15,105,110	\$22,040,704	\$52,347,323	\$55,430,993	\$50,476,126	\$43,799,513	\$40,774,033	\$39,396,964	\$38,663,880	\$38,419,004	\$37,980,558	\$38,441,960	\$36,755,839
(29)	Month's Average Balance	[(18) + (28)] ÷ 2	\$13,441,392	\$18,609,726	\$37,232,189	\$53,964,260	\$53,051,878	\$47,244,832	\$42,378,997	\$40,170,982	\$39,108,838	\$38,620,329	\$38,277,683	\$38,285,979	\$36,755,839
(30)	Interest Rate (BOA Prime minus 200 bps)		5.00%	4.83%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	
(31)	Interest Applied	[(29) x (30)] - 365 x (1)	\$55,239	\$76,351	\$150,204	\$196,637	\$214,024	\$184,449	\$170,967	\$156,832	\$157,775	\$155,804	\$149,440	\$154,455	\$1,822,177
(32)	Gas Procurement Incentive/(penalty)		\$18,399	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$18,399
(33)	VARIABLE ENDING UNDER/(OVER) RECOVERY	(28) + (31) + (32)	\$15,178,748	\$22,117,054	\$52,497,527	\$55,627,630	\$50,690,150	\$43,983,962	\$40,945,000	\$39,553,796	\$38,821,655	\$38,574,808	\$38,129,999	\$38,596,415	\$38,596,415
(34)	GCR Deferred Summary														
(35)	Beginning Under/(Over) Recovery	(3) + (18)	(\$2,146,392)	\$2,810,913	\$2,509,055	\$27,274,724	\$24,398,670	\$16,378,975	\$8,923,618	\$8,065,096	\$10,262,460	\$13,637,248	\$17,667,300	\$21,445,783	(\$2,146,392)
(36)	Gas Costs	Sum(4)-(6),(19)-(21)	\$17,631,933	\$28,433,902	\$58,636,403	\$33,705,505	\$19,934,191	\$13,055,116	\$10,627,847	\$9,406,759	\$9,009,397	\$9,172,455	\$9,133,723	\$10,792,315	\$229,539,345
(37)	Inventory Finance	(22) + (23)	\$131,230	\$116,111	\$82,893	\$63,607	\$65,585	\$67,802	\$81,335	\$85,262	\$86,177	\$87,112	\$93,963	\$109,274	\$1,070,351
(38)	Working Capital	(8) + (24)	\$126,078	\$204,603	\$423,771	\$245,405	\$143,641	\$93,836	\$76,263	\$67,422	\$64,545	\$65,726	\$65,445	\$77,453	\$1,652,187
(39)	NGPMP Credits	(7)	(\$1,507,649)	(\$6,076,656)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$22,660,798)
(40)	Total Costs	Sum(36)-(39)	\$16,881,592	\$22,677,959	\$57,635,417	\$32,504,867	\$18,635,768	\$11,709,105	\$9,277,795	\$8,051,794	\$7,652,469	\$7,817,644	\$7,785,482	\$9,471,392	\$209,601,285
(41)	Revenue	(10) + (26)	\$11,444,011	\$22,990,707	\$32,929,705	\$35,474,895	\$26,737,551	\$19,213,758	\$10,170,516	\$5,890,136	\$4,325,794	\$3,850,610	\$4,083,200	\$5,236,961	\$182,347,845
(42)	Monthly Under/(Over) Recovery	(40) - (41)	\$4,937,580	(\$312,748)	\$24,705,712	(\$2,970,028)	(\$8,101,783)	(\$7,504,653)	(\$892,721)	\$2,161,657	\$3,326,676	\$3,967,034	\$3,702,282	\$4,234,431	\$27,253,440
(43)	Prelim. Ending Under/(Over) Recovery	(35) + (42)	\$2,791,189	\$2,498,164	\$27,214,768	\$24,304,697	\$16,296,887	\$8,874,322	\$8,030,897	\$10,226,754	\$13,589,136	\$17,604,282	\$21,369,581	\$25,680,214	\$25,680,214
(44)	Month's Average Balance	[(35) + (43)] ÷ 2	\$322,398	\$2,654,539	\$14,861,912	\$25,789,710	\$20,347,779	\$12,626,648	\$8,477,257	\$9,145,925	\$11,925,798	\$15,620,765	\$19,518,440	\$23,562,999	\$25,680,214
(45)	Interest Rate (BOA Prime minus 200 bps)		5.00%	4.83%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	
(46)	Interest Applied	(15) + (31)	\$13,325	\$10,891	\$59,957	\$93,973	\$82,088	\$49,296	\$34,199	\$35,707	\$48,112	\$63,018	\$76,202	\$95,059	\$649,826
(47)	Gas Purchase Plan Incentives/(Penalties)	(32)	\$18,399	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$18,399
(48)	ENDING UNDER/(OVER) RECOVERY W/ INTEREST	(43) + (46) + (47)	\$2,810,913	\$2,509,055	\$27,274,724	\$24,398,670	\$16,378,975	\$8,923,618	\$8,065,096	\$10,262,460	\$13,637,248	\$17,667,300	\$21,445,783	\$25,775,273	\$25,775,273

Supply Estimates Actuals for Filing

	<u>Nov</u> <u>Actual</u> (a)	<u>Dec</u> <u>Actual</u> (b)	<u>Jan</u> <u>Actual</u> (c)	<u>Feb</u> <u>Actual</u> (d)	<u>Mar</u> <u>Forecast</u> (e)	<u>Apr</u> <u>Forecast</u> (f)	<u>May</u> <u>Forecast</u> (g)	<u>Jun</u> <u>Forecast</u> (h)	<u>Jul</u> <u>Forecast</u> (i)	<u>Aug</u> <u>Forecast</u> (j)	<u>Sep</u> <u>Forecast</u> (k)	<u>Oct</u> <u>Forecast</u> (l)	<u>Nov-Oct</u> <u>Forecast</u> (m)
<u>Description</u>	<u>Reference</u>												
(1) SUPPLY FIXED COSTS - Pipeline Delivery													
(2) AGT M3	\$438,710	\$440,364	\$442,331	\$442,331	\$174,487	\$174,487	\$174,487	\$174,487	\$174,487	\$174,487	\$174,487	\$174,487	\$3,159,631
(3) AIM	\$927,625	\$925,463	\$933,613	\$914,553	\$781,498	\$781,498	\$781,498	\$781,498	\$781,498	\$781,498	\$781,498	\$781,498	\$9,953,238
(4) Dawn via PNGTS	\$1,294,033	\$1,325,385	\$1,300,881	\$1,215,733	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$13,611,090
(5) Dawn via Waddington	\$10,192	\$10,176	\$10,184	\$9,700	\$22,061	\$22,061	\$22,061	\$22,061	\$22,061	\$22,061	\$22,061	\$22,061	\$216,741
(6) EGTS	\$9,193	\$9,193	\$9,193	\$9,379	\$9,421	\$9,421	\$9,421	\$9,421	\$9,421	\$9,421	\$9,421	\$9,421	\$112,323
(7) Manchester Lateral	\$262,800	\$262,800	\$262,800	\$262,800	\$216,276	\$216,276	\$216,276	\$216,276	\$216,276	\$216,276	\$216,276	\$216,276	\$2,781,409
(8) Niagara	\$6,241	\$6,224	\$6,232	\$5,716	\$5,974	\$5,974	\$5,974	\$5,974	\$5,974	\$5,974	\$5,974	\$5,974	\$72,204
(9) TCO (Pool)	\$894,034	\$165,850	\$894,754	\$894,394	\$849,526	\$849,526	\$849,526	\$849,526	\$849,526	\$849,526	\$849,526	\$849,526	\$9,645,239
(10) TETCO CDS Long Haul	\$1,663,179	\$1,669,795	\$1,677,480	\$1,734,486	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$18,334,862
(11) TETCO SCT Long Haul	\$32,045	\$31,997	\$31,992	\$33,019	\$25,970	\$25,970	\$25,970	\$25,970	\$25,970	\$25,970	\$25,970	\$25,970	\$336,814
(13) TGP ConneXion	\$264,274	\$264,088	\$264,181	\$264,181	\$221,980	\$221,980	\$221,980	\$221,980	\$221,980	\$221,980	\$221,980	\$221,980	\$2,832,564
(12) TGP Long Haul	\$512,711	\$512,242	\$512,477	\$469,865	\$412,761	\$412,761	\$412,761	\$412,761	\$412,761	\$412,761	\$412,761	\$412,761	\$5,309,380
(14) Transco	\$12,559	\$12,791	\$12,791	\$12,097	\$12,238	\$12,238	\$12,238	\$12,238	\$12,238	\$12,238	\$12,238	\$12,238	\$148,142
(15) AMA Credits	(\$239,642)	(\$218,890)	(\$230,427)	(\$211,215)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$2,851,278)
(16) Less Credits from Mkter Releases*	(\$931,041)	(\$924,787)	(\$990,032)	(\$869,191)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$3,715,051)
(17) STORAGE FIXED COSTS - Facilities													
(18) Columbia FSS	\$23,219	(\$11,940)	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$243,466
(19) Exeter LNG	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(20) Providence LNG	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$3,972,240
(21) Tennessee FSMA	\$39,253	\$39,284	\$39,253	\$35,969	\$37,611	\$37,611	\$37,611	\$37,611	\$37,611	\$37,611	\$37,611	\$37,611	\$454,647
(22) Tetco FSS1	\$2,481	\$2,496	\$2,470	\$2,625	\$3,917	\$3,917	\$3,917	\$3,917	\$3,917	\$3,917	\$3,917	\$3,917	\$41,409
(23) Tetco SS1	\$133,721	\$133,086	\$133,738	\$140,535	\$159,773	\$159,773	\$159,773	\$159,773	\$159,773	\$159,773	\$159,773	\$159,773	\$1,819,262
(24) EGTS GSS	\$57,381	\$57,381	\$57,381	\$57,381	\$80,239	\$80,239	\$80,239	\$80,239	\$80,239	\$80,239	\$80,239	\$80,239	\$871,438
(25) EGTS GSSTE	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$887,291
(26) Less Credits from Mkter Releases	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(27) STORAGE FIXED COSTS - Delivery													
(28) Storage Delivery	\$490,019	\$444,259	\$473,286	\$473,240	\$576,035	\$532,120	\$532,120	\$532,120	\$532,120	\$532,120	\$532,120	\$532,120	\$6,181,682
(29) LNG	\$764,225	\$770,891	\$770,891	\$750,892	\$823,842	\$823,842	\$823,842	\$823,842	\$823,842	\$823,842	\$823,842	\$823,842	\$9,647,637
(30) Confidential Pipeline and Peaking Supplies	\$1,045,261	\$1,227,091	\$1,324,924	\$1,310,524	\$2,403,839	\$331,736	\$294,543	\$294,543	\$294,543	\$294,543	\$294,543	\$294,543	\$9,410,632
(31) TOTAL FIXED COSTS	\$8,117,432	\$7,560,197	\$8,368,573	\$8,387,193	\$9,509,862	\$7,393,845	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$93,477,014

Supply Estimates Actuals for Filing

		<u>Nov</u> Actual (a)	<u>Dec</u> Actual (b)	<u>Jan</u> Actual (c)	<u>Feb</u> Actual (d)	<u>Mar</u> Forecast (e)	<u>Apr</u> Forecast (f)	<u>May</u> Forecast (g)	<u>Jun</u> Forecast (h)	<u>Jul</u> Forecast (i)	<u>Aug</u> Forecast (j)	<u>Sep</u> Forecast (k)	<u>Oct</u> Forecast (l)	<u>Nov-Oct</u> (m)
	<u>Description</u>													
(32)	VARIABLE COMMODITY COSTS													
(33)	AIM at Ramapo	\$0	\$0	\$0	\$0	\$43,019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$43,019
(34)	Beverly	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(35)	Dawn via IGTS	\$0	\$0	\$0	\$0	\$290	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$290
(36)	Dawn via PNGTS	\$0	\$0	\$0	\$0	\$143,850	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$143,850
(37)	Dracut	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(38)	EGTS SP	\$0	\$0	\$0	\$0	\$39,701	\$37,817	\$37,746	\$39,064	\$44,554	\$45,085	\$38,298	\$38,226	\$320,490
(39)	Millennium	\$0	\$0	\$0	\$0	\$103,695	\$0	\$0	\$0	\$635,518	\$0	\$0	\$0	\$739,213
(40)	Niagara	\$0	\$0	\$0	\$0	\$83,968	\$0	\$0	\$0	\$92,384	\$94,684	\$0	\$0	\$271,036
(41)	TCO Appalachia	\$0	\$0	\$0	\$0	\$2,552,483	\$96,463	\$131,024	\$99,654	\$0	\$0	\$0	\$59,242	\$2,938,865
(42)	Tetco M2 CDS	\$0	\$0	\$0	\$0	\$2,649,932	\$180,963	\$1,061,807	\$1,264,395	\$699,794	\$1,476,410	\$2,079,880	\$2,727,351	\$12,140,533
(43)	Tetco M2 SCT	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(44)	Tetco M3	\$0	\$0	\$0	\$0	\$929,114	\$4,025,200	\$2,415,871	\$0	\$0	\$0	\$0	\$1,180,118	\$8,550,302
(45)	TGP Z4 Cnx	\$0	\$0	\$0	\$0	\$774,199	\$635,385	\$692,577	\$745,869	\$244,373	\$277,820	\$567,180	\$736,165	\$4,673,569
(46)	TGP Z4 LH	\$0	\$0	\$0	\$0	\$1,177,580	\$323,185	\$59,775	\$0	\$0	\$0	\$742	\$461,225	\$2,022,507
(47)	Transco Leidy	\$0	\$0	\$0	\$0	\$5,550	\$5,141	\$5,082	\$5,286	\$6,110	\$6,164	\$5,161	\$5,175	\$43,671
(48)	Winter Liquid	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(49)	Confidential Pipeline and Peaking Supplies	\$0	\$0	\$0	\$0	\$24,607	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$24,607
(50)	Variable Transportation Costs	\$0	\$0	\$0	\$0	\$426,514	\$227,902	\$399,530	\$128,821	\$101,528	\$136,839	\$159,522	\$500,007	\$2,080,663
(51)	Total Pipeline Commodity Charges	Sum[(33):(50)]	\$9,019,647	\$18,908,372	\$43,388,609	\$28,683,446	\$8,954,501	\$5,532,055	\$4,803,412	\$2,283,090	\$1,824,261	\$2,037,003	\$2,850,784	\$5,707,508
(52)	INJECTIONS & HEDGING IMPACT													
(53)	Hedging	\$1,478,640	(\$183,185)	(\$120,559)	(\$9,314,068)	\$2,239,789	\$592,824	\$597,365	\$460,535	\$71,808	\$25,087	\$56,898	\$123,495	(\$3,971,371)
(54)	Less: Costs of Injections	\$0	\$0	\$0	\$0	\$0	(\$667,010)	(\$2,126,148)	(\$678,651)	(\$226,400)	(\$225,712)	(\$1,104,233)	(\$2,368,936)	(\$7,397,090)
(55)	TOTAL VARIABLE SUPPLY COSTS	Sum[(51):(54)]	\$10,498,287	\$18,725,187	\$43,268,049	\$19,369,378	\$11,194,290	\$5,457,869	\$3,274,628	\$2,064,974	\$1,669,669	\$1,836,379	\$3,462,066	\$122,624,226
(56)	TOTAL VARIABLE STORAGE COSTS		\$637,741	\$2,222,426	\$5,427,672	\$2,726,510	\$1,366,865	\$335,668	\$103,084	\$91,650	\$89,593	\$85,942	\$80,139	\$13,247,403
(57)	TOTAL VARIABLE COSTS	(55) + (56)	\$11,136,028	\$20,947,613	\$48,695,721	\$22,095,888	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180
(58)	TOTAL SUPPLY COSTS	(31) + (57)	\$19,253,460	\$28,507,810	\$57,064,294	\$30,483,081	\$22,071,017	\$13,187,382	\$10,734,364	\$9,513,276	\$9,115,914	\$9,278,973	\$9,240,240	\$10,898,832

Supply Estimates Actuals for Filing

		<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov-Oct</u>
		<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
<u>Description</u>	<u>Reference</u>													
(59) Storage Costs for FT-2 Calculation														
(60) Total Managed and Storage Costs		\$2,732,194	\$2,843,303	\$3,003,972	\$2,986,088	\$4,231,394	\$2,115,377	\$2,115,377	\$2,115,377	\$2,115,377	\$2,115,377	\$2,115,377	\$2,115,377	\$30,604,586
(61) Supply Related System Pressure to DAC		(\$986,458)	(\$1,168,288)	(\$1,266,121)	(\$1,251,721)	(\$2,231,165)	(\$226,605)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$8,335,493)
(62) Inventory Financing		\$131,230	\$116,111	\$82,893	\$63,607	\$65,585	\$67,802	\$81,335	\$85,262	\$86,177	\$87,112	\$93,963	\$109,274	\$1,070,351
(63) Supply Related LNG O&M Costs		\$192,721	\$148,662	\$79,300	\$60,893	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$1,034,791
(64) Working Capital Requirement		<u>\$12,605</u>	<u>\$12,094</u>	<u>\$12,548</u>	<u>\$12,523</u>	<u>\$14,442</u>	<u>\$13,637</u>	<u>\$13,823</u>	<u>\$13,823</u>	<u>\$13,823</u>	<u>\$13,823</u>	<u>\$13,823</u>	<u>\$13,823</u>	\$160,788
(65) TOTAL FT-2 STORAGE FIXED COSTS	Sum[(60):(64)]	\$2,082,291	\$1,951,882	\$1,912,592	\$1,871,390	\$2,149,408	\$2,039,363	\$2,078,831	\$2,082,758	\$2,083,673	\$2,084,608	\$2,091,458	\$2,106,769	\$24,535,023
(66) System Storage MDQ (Dth)		196,220	195,510	194,840	195,090	196,390	196,390	196,390	196,390	196,390	196,390	196,390	196,390	\$2,352,783
(67) FT-2 Storage Cost per MDQ (Dth)	(65) ÷ (66)	\$10.6120	\$9.9835	\$9.8162	\$9.5924	\$10.9446	\$10.3842	\$10.5852	\$10.6052	\$10.6099	\$10.6146	\$10.6495	\$10.7275	\$10.4281
(68) Pipeline Variable	(57)	\$11,136,028	\$20,947,613	\$48,695,721	\$22,095,888	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180	\$135,871,629
(69) Less Non-firm Gas Costs		(\$139,070)	(\$339,162)	(\$500,043)	(\$338,843)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,317,119)
(70) Mkter Over-takes/Undertakes		(\$769,945)	\$1,116,521	\$3,317,254	\$4,380,689	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$8,044,519
(71) Less Mkter FT-2 Daily weather true-up		<u>\$56,039</u>	<u>\$143,171</u>	<u>(\$83,469)</u>	<u>\$346,218</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	\$461,959
(72) TOTAL FIRM COMMODITY COSTS	Sum[(68):(71)]	\$10,283,052	\$21,868,143	\$51,429,463	\$26,483,952	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180	\$143,060,989

GCR Revenue

		<u>Nov</u> <u>Actual</u>	<u>Dec</u> <u>Actual</u>	<u>Jan</u> <u>Actual</u>	<u>Feb</u> <u>Actual</u>	<u>Mar</u> <u>Forecast</u>	<u>Apr</u> <u>Forecast</u>	<u>May</u> <u>Forecast</u>	<u>Jun</u> <u>Forecast</u>	<u>Jul</u> <u>Forecast</u>	<u>Aug</u> <u>Forecast</u>	<u>Sep</u> <u>Forecast</u>	<u>Oct</u> <u>Forecast</u>	<u>Nov-Oct</u>
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Description	Reference													
(1) <u>I. Fixed Cost Revenue</u>														
(2) (a) Low Load dth	Sch. 6, Sum[(24):(28), (30)]	1,608,405	3,513,086	5,013,283	5,361,309	4,187,850	2,987,373	1,545,092	863,370	619,112	547,059	577,996	758,645	27,582,580
(3) Fixed Cost Factor	(4) ÷ (2)	\$2.4178	\$2.0321	\$2.0281	\$2.0297	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276
(4) Low Load Revenue		\$3,888,755	\$7,138,796	\$10,167,512	\$10,881,677	\$8,491,412	\$6,057,289	\$3,132,876	\$1,750,596	\$1,255,331	\$1,109,233	\$1,171,963	\$1,538,252	\$56,583,690
(5) (b) High Load dth	Sch. 6, Sum[(22), (23), (29), (31)]	71,422	107,696	124,397	156,231	79,296	69,509	57,050	50,115	42,212	37,459	44,541	49,822	889,751
(6) Fixed Cost Factor	(7) ÷ (5)	\$1.8028	\$1.4740	\$1.4753	\$1.4813	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718
(7) High Load Revenue		\$128,761	\$158,745	\$183,523	\$231,431	\$116,707	\$102,304	\$83,965	\$73,759	\$62,128	\$55,132	\$65,555	\$73,328	\$1,335,338
(8) Sub-total throughput Dth	(2) + (5)	1,679,827	3,620,782	5,137,680	5,517,540	4,267,145	3,056,882	1,602,141	913,486	661,324	584,517	622,537	808,467	28,472,331
(9) FT-2 Storage Revenue from marketers		\$240,014	\$387,355	\$899,046	\$530,762	\$235,057	\$235,057	\$235,057	\$235,057	\$235,057	\$235,057	\$235,057	\$235,057	\$3,937,637
(10) TOTAL FIXED REVENUE	(4) + (7) + (9)	\$4,257,530	\$7,684,896	\$11,250,081	\$11,643,870	\$8,843,176	\$6,394,650	\$3,451,898	\$2,059,413	\$1,552,515	\$1,399,422	\$1,472,576	\$1,846,637	\$61,856,665
(11) <u>II. Variable Cost Revenue</u>														
(12) (a) Firm Sales dth	(8)	1,679,827	3,620,782	5,137,680	5,517,540	4,267,145	3,056,882	1,602,141	913,486	661,324	584,517	622,537	808,467	28,472,331
(13) Variable Supply Cost Factor	(14) ÷ (12)	\$4.2651	\$4.2025	\$4.1934	\$4.1984	\$4.1935	\$4.1935	\$4.1935	\$4.1935	\$4.1935	\$4.1935	\$4.1935	\$4.1935	\$4.1935
(14) Variable Supply Revenue		\$7,164,602	\$15,216,372	\$21,544,512	\$23,164,773	\$17,894,374	\$12,819,108	\$6,718,618	\$3,830,723	\$2,773,278	\$2,451,188	\$2,610,625	\$3,390,325	\$119,578,499
(15) (b) TSS Sales dth	Sch. 6, line (20)	8,414	17,504	24,664	30,289	0	0	0	0	0	0	0	0	\$80,871
(16) TSS Surcharge Factor	Company's website	\$0.0194	\$0.0179	\$0.2729	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
(17) TSS Surcharge Revenue	(16) x (17)	\$163	\$313	\$6,731	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$7,207
(18) (c) Default Sales dth	Sch. 6, line (60)	3,086	14,071	8,688	32,683	0	0	0	0	0	0	0	0	58,529
(19) Variable Supply Cost Factor	(20) ÷ (18)	\$7.04	\$6.33	\$14.78	\$20.39	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(20) Variable Supply Revenue		\$21,716	\$89,125	\$128,381	\$666,252	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$905,474
(21) (d) Deferred Responsibility		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(22) (e) FT-1 Storage and Peaking														
(23) TOTAL VARIABLE REVENUE	(14)+(17)+(20)+(21)	\$7,186,482	\$15,305,811	\$21,679,624	\$23,831,025	\$17,894,374	\$12,819,108	\$6,718,618	\$3,830,723	\$2,773,278	\$2,451,188	\$2,610,625	\$3,390,325	\$120,491,180
(24) Total GAS COST REVENUE (w/o FT-2)	(10) + (23)	\$11,444,011	\$22,990,707	\$32,929,705	\$35,474,895	\$26,737,551	\$19,213,758	\$10,170,516	\$5,890,136	\$4,325,794	\$3,850,610	\$4,083,200	\$5,236,961	\$182,347,845

WORKING CAPITAL

		<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov-Oct</u>
		<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
<u>Description</u>	<u>Reference</u>													
(1) Supply Fixed Costs	Sch. 1, line (4)	\$8,117,432	\$7,560,197	\$8,368,573	\$8,387,193	\$9,509,862	\$7,393,845	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$93,477,014
(2) Less System Pressure to DAC	Sch. 1, line (5)	(\$986,458)	(\$1,168,288)	(\$1,266,121)	(\$1,251,721)	(\$2,231,165)	(\$226,605)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$8,335,493)
(3) Total Adjustments	(2)	<u>(\$986,458)</u>	<u>(\$1,168,288)</u>	<u>(\$1,266,121)</u>	<u>(\$1,251,721)</u>	<u>(\$2,231,165)</u>	<u>(\$226,605)</u>	<u>(\$200,856)</u>	<u>(\$200,856)</u>	<u>(\$200,856)</u>	<u>(\$200,856)</u>	<u>(\$200,856)</u>	<u>(\$200,856)</u>	<u>(\$8,335,493)</u>
(4) Allowable Working Capital Costs	(1) + (3)	\$7,130,974	\$6,391,909	\$7,102,452	\$7,135,473	\$7,278,697	\$7,167,240	\$7,155,796	\$7,155,796	\$7,155,796	\$7,155,796	\$7,155,796	\$7,155,796	\$85,141,521
(5) Number of Days Lag	Dkt 4770	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92
(6) Working Capital Requirement	[(4) x (5)] ÷ 365	\$643,155	\$576,498	\$640,583	\$643,561	\$656,479	\$646,426	\$645,394	\$645,394	\$645,394	\$645,394	\$645,394	\$645,394	\$645,394
(7) Cost of Capital	Dkt 4770	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
(8) Return on Working Capital Requirem	(6) x (7)	\$43,542	\$39,029	\$43,367	\$43,569	\$44,444	\$43,763	\$43,693	\$43,693	\$43,693	\$43,693	\$43,693	\$43,693	\$43,693
(9) Cost of Debt (Long Term Debt + Shs	Dkt 4770	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%
(10) Interest Expense	(6) x (9)	\$13,120	\$11,761	\$13,068	\$13,129	\$13,392	\$13,187	\$13,166	\$13,166	\$13,166	\$13,166	\$13,166	\$13,166	\$13,166
(11) Taxable Income	(8) - (10)	\$30,421	\$27,268	\$30,300	\$30,440	\$31,051	\$30,576	\$30,527	\$30,527	\$30,527	\$30,527	\$30,527	\$30,527	\$30,527
(12) 1 - Combined Tax Rate	Dkt 4770	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79
(13) Return and Tax Requirement	(11) ÷ (12)	\$38,508	\$34,517	\$38,354	\$38,532	\$39,306	\$38,704	\$38,642	\$38,642	\$38,642	\$38,642	\$38,642	\$38,642	\$38,642
(14) Supply Fixed Working Capital Re	(10) + (13)	\$51,628	\$46,277	\$51,422	\$51,661	\$52,698	\$51,891	\$51,808	\$51,808	\$51,808	\$51,808	\$51,808	\$51,808	\$616,425
(15) Supply Variable Costs	Sch. 1, line (19)	\$10,283,052	\$21,868,143	\$51,429,463	\$26,483,952	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180	\$143,060,989
(16) Less: Bal. Related Syst. Pressure Co	Sch. 1, line (20)													
(17) Total Adjustments	(16)	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>
(18) Allowable Working Capital Costs	(15) + (17)	\$10,283,052	\$21,868,143	\$51,429,463	\$26,483,952	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180	\$143,060,989
(19) Number of Days Lag	Dkt 4770	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92
(20) Working Capital Requirement	[(18) x (19)] ÷ 365	\$927,447	\$1,972,327	\$4,638,515	\$2,388,635	\$1,132,913	\$522,529	\$304,642	\$194,510	\$158,671	\$173,378	\$169,884	\$319,475	\$319,475
(21) Cost of Capital	Dkt 4770	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
(22) Return on Working Capital Requirem	(20) x (21)	\$62,788	\$133,527	\$314,027	\$161,711	\$76,698	\$35,375	\$20,624	\$13,168	\$10,742	\$11,738	\$11,501	\$21,628	\$21,628
(23) Cost of Debt (Long Term Debt + Shs	Dkt 4770	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%
(24) Interest Expense	(20) x (23)	\$18,920	\$40,235	\$94,626	\$48,728	\$23,111	\$10,660	\$6,215	\$3,968	\$3,237	\$3,537	\$3,466	\$6,517	\$6,517
(25) Taxable Income	(22) - (24)	\$43,868	\$93,291	\$219,402	\$112,982	\$55,587	\$24,716	\$14,410	\$9,200	\$7,505	\$8,201	\$8,036	\$15,111	\$15,111
(26) 1 - Combined Tax Rate	Dkt 4770	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79
(27) Return and Tax Requirement	(25) ÷ (26)	\$55,529	\$118,090	\$277,724	\$143,016	\$67,831	\$31,286	\$18,240	\$11,646	\$9,500	\$10,381	\$10,172	\$19,128	\$19,128
(28) Supply Variable Working Capital	(24) + (27)	\$74,449	\$158,325	\$372,349	\$191,744	\$90,943	\$41,945	\$24,455	\$15,614	\$12,737	\$13,918	\$13,637	\$25,645	\$1,035,762

INVENTORY FINANCE

		<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov-Oct</u>
		<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
<u>Description</u>	<u>Reference</u>													
(1) Storage Inventory Balance		\$11,199,806	\$9,642,526	\$7,663,995	\$6,409,877	\$7,409,829	\$7,588,430	\$9,064,131	\$9,547,908	\$9,553,012	\$9,553,012	\$10,464,244	\$12,182,909	
(2) Monthly Storage Deferral/Amortization		<u>\$1,723,779</u>	<u>\$1,279,506</u>	<u>\$710,838</u>	<u>\$248,795</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	
(3) Subtotal	(1) + (2)	\$12,923,585	\$10,922,032	\$8,374,833	\$6,658,671	\$7,409,829	\$7,588,430	\$9,064,131	\$9,547,908	\$9,553,012	\$9,553,012	\$10,464,244	\$12,182,909	
(4) Cost of Capital	Dkt 4770	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	
(5) Return on Working Capital Requirement	(3) x (4)	\$874,927	\$739,422	\$566,976	\$450,792	\$501,645	\$513,737	\$613,642	\$646,393	\$646,739	\$646,739	\$708,429	\$824,783	\$7,734,224
(6) Weighted Cost of Debt	Dkt 4770	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	
(7) Interest Charges Financed	(3) x (6)	\$263,641	\$222,809	\$170,847	\$135,837	\$151,161	\$154,804	\$184,908	\$194,777	\$194,881	\$194,881	\$213,471	\$248,531	\$2,330,549
(8) Taxable Income	(5) - (7)	\$611,286	\$516,612	\$396,130	\$314,955	\$350,485	\$358,933	\$428,733	\$451,616	\$451,857	\$451,857	\$494,959	\$576,252	
(9) 1 - Combined Tax Rate	Dkt 4770	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(10) Return and Tax Requirement	(8) ÷ (9)	\$773,779	\$653,939	\$501,430	\$398,677	\$443,652	\$454,345	\$542,701	\$571,666	\$571,972	\$571,972	\$626,530	\$729,432	\$6,840,095
(11) Working Capital Requirement	(7) + (10)	\$1,037,420	\$876,749	\$672,276	\$534,514	\$594,812	\$609,149	\$727,609	\$766,443	\$766,853	\$766,853	\$840,001	\$977,964	\$9,170,644
(12) Monthly Average	(11) ÷ 12	\$86,452	\$73,062	\$56,023	\$44,543	\$49,568	\$50,762	\$60,634	\$63,870	\$63,904	\$63,904	\$70,000	\$81,497	\$764,220
(13) LNG Inventory Balance		\$6,693,909	\$6,435,308	\$4,016,764	\$2,849,913	\$2,394,473	\$2,547,214	\$3,094,578	\$3,197,802	\$3,329,505	\$3,469,275	\$3,582,137	\$4,152,295	
(14) Cost of Capital	Dkt 4770	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	
(15) Return on Working Capital Requirement	(13) x (14)	\$453,178	\$435,670	\$271,935	\$192,939	\$162,106	\$172,446	\$209,503	\$216,491	\$225,407	\$234,870	\$242,511	\$281,110	\$3,098,167
(16) Weighted Cost of Debt	Dkt 4770	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	
(17) Interest Charges Financed	(13) x (16)	\$136,556	\$131,280	\$81,942	\$58,138	\$48,847	\$51,963	\$63,129	\$65,235	\$67,922	\$70,773	\$73,076	\$84,707	\$933,569
(18) Taxable Income	(15) - (17)	\$316,622	\$304,390	\$189,993	\$134,801	\$113,259	\$120,483	\$146,374	\$151,256	\$157,486	\$164,097	\$169,435	\$196,404	
(19) 1 - Combined Tax Rate	Dkt 4770	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(20) Return and Tax Requirement	(18) ÷ (19)	\$400,787	\$385,304	\$240,497	\$170,634	\$143,365	\$152,510	\$185,283	\$191,463	\$199,349	\$207,717	\$214,475	\$248,612	\$2,739,997
(21) Working Capital Requirement	(17) + (20)	\$537,343	\$516,584	\$322,439	\$228,772	\$192,212	\$204,474	\$248,412	\$256,698	\$267,271	\$278,491	\$287,550	\$333,319	\$3,673,566
(22) Monthly Average	(21) ÷ 12	\$44,779	\$43,049	\$26,870	\$19,064	\$16,018	\$17,039	\$20,701	\$21,392	\$22,273	\$23,208	\$23,963	\$27,777	\$306,131
(23) TOTAL GCR Inventory Financing Costs	(12) + (22)	\$131,230	\$116,111	\$82,893	\$63,607	\$65,585	\$67,802	\$81,335	\$85,262	\$86,177	\$87,112	\$93,963	\$109,274	\$1,070,351

Actual Dth Usage for Filing

	<u>Nov</u> <u>Actual</u>	<u>Dec</u> <u>Actual</u>	<u>Jan</u> <u>Actual</u>	<u>Feb</u> <u>Actual</u>	<u>Mar</u> <u>Forecast</u>	<u>Apr</u> <u>Forecast</u>	<u>May</u> <u>Forecast</u>	<u>Jun</u> <u>Forecast</u>	<u>Jul</u> <u>Forecast</u>	<u>Aug</u> <u>Forecast</u>	<u>Sep</u> <u>Forecast</u>	<u>Oct</u> <u>Forecast</u>	<u>Nov-Oct</u>
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
THROUGHPUT (Dth)													
<u>Rate Class</u>													
(1) SALES													
(2) Residential Non-Heating	22,908	42,855	58,226	61,500	31,295	26,094	18,018	12,824	10,440	9,901	10,578	13,668	318,306
(3) Residential Non-Heating Low Income	1,636	2,537	3,337	3,630	2,286	2,110	1,451	1,021	824	724	774	1,028	21,358
(4) Residential Heating	1,109,606	2,448,726	3,490,353	3,717,114	2,876,908	2,073,184	1,087,131	594,919	412,329	362,322	380,623	490,598	19,043,813
(5) Residential Heating Low Income	106,303	209,952	282,811	295,762	273,613	217,290	116,926	67,274	46,870	39,870	42,639	54,212	1,753,519
(6) Small C&I	130,015	320,270	488,554	534,506	409,185	257,472	110,520	55,591	43,310	38,657	40,526	55,562	2,484,168
(7) Medium C&I	213,980	425,891	599,296	616,832	503,430	356,922	190,194	125,403	104,832	96,847	106,456	138,207	3,478,289
(8) Large LLF	35,053	78,012	109,270	123,692	113,339	77,973	38,475	19,140	11,241	8,222	6,595	17,416	638,427
(9) Large HLF	20,390	28,856	35,005	33,409	30,238	27,755	21,394	20,360	16,630	14,528	18,850	19,292	286,706
(10) Extra Large LLF	5,633	13,656	19,891	45,441	11,375	4,533	1,847	1,044	531	1,140	1,157	2,650	108,897
(11) Extra Large HLF	25,891	32,523	26,275	55,365	15,477	13,551	16,187	15,910	14,318	12,307	14,339	15,834	257,976
(12) Total SALES	1,671,413	3,603,279	5,113,016	5,487,251	4,267,145	3,056,882	1,602,141	913,486	661,324	584,517	622,537	808,467	28,391,460
(13) TSS													
(14) TSS Small C&I	147	661	1,207	1,971	0	0	0	0	0	0	0	0	3,987
(15) TSS Medium C&I	3,211	7,021	9,471	10,706	0	0	0	0	0	0	0	0	30,408
(16) TSS Large LLF	4,458	8,897	12,432	15,285	0	0	0	0	0	0	0	0	41,072
(17) TSS Large HLF	598	925	1,555	2,327	0	0	0	0	0	0	0	0	5,405
(18) TSS Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(19) TSS Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(20) Total TSS	8,414	17,504	24,664	30,289	0	0	0	0	0	0	0	0	80,871
(21) Sales & TSS THROUGHPUT													
(22) Residential Non-Heating	22,908	42,855	58,226	61,500	31,295	26,094	18,018	12,824	10,440	9,901	10,578	13,668	318,306
(23) Residential Non-Heating Low Income	1,636	2,537	3,337	3,630	2,286	2,110	1,451	1,021	824	724	774	1,028	21,358
(24) Residential Heating	1,109,606	2,448,726	3,490,353	3,717,114	2,876,908	2,073,184	1,087,131	594,919	412,329	362,322	380,623	490,598	19,043,813
(25) Residential Heating Low Income	106,303	209,952	282,811	295,762	273,613	217,290	116,926	67,274	46,870	39,870	42,639	54,212	1,753,519
(26) Small C&I	130,162	320,931	489,761	536,477	409,185	257,472	110,520	55,591	43,310	38,657	40,526	55,562	2,488,155
(27) Medium C&I	217,191	432,911	608,767	627,538	503,430	356,922	190,194	125,403	104,832	96,847	106,456	138,207	3,508,697
(28) Large LLF	39,511	86,909	121,701	138,977	113,339	77,973	38,475	19,140	11,241	8,222	6,595	17,416	679,499
(29) Large HLF	20,988	29,781	36,560	35,736	30,238	27,755	21,394	20,360	16,630	14,528	18,850	19,292	292,111
(30) Extra Large LLF	5,633	13,656	19,891	45,441	11,375	4,533	1,847	1,044	531	1,140	1,157	2,650	108,897
(31) Extra Large HLF	25,891	32,523	26,275	55,365	15,477	13,551	16,187	15,910	14,318	12,307	14,339	15,834	257,976
(32) Total SALES & TSS THROUGHPUT	1,679,827	3,620,782	5,137,680	5,517,540	4,267,145	3,056,882	1,602,141	913,486	661,324	584,517	622,537	808,467	28,472,331
(33) FT-1 TRANSPORTATION													
(34) FT-1 Small	0	0	0	0	0	0	0	0	0	0	0	0	0
(35) FT-1 Medium	39,744	20,608	75,699	82,188	68,743	46,081	28,893	21,639	18,554	18,679	21,701	30,546	473,074
(36) FT-1 Large LLF	47,563	45,005	113,694	124,633	98,495	66,413	35,134	19,657	13,421	12,342	15,857	33,288	625,502
(37) FT-1 Large HLF	22,879	6,082	38,468	45,228	37,030	30,922	28,515	25,339	22,247	24,653	27,697	31,468	340,527
(38) FT-1 Extra Large LLF	62,873	78,813	127,392	178,007	166,529	110,644	60,347	31,767	21,601	20,501	27,662	54,005	940,142
(39) FT-1 Extra Large HLF	388,400	23,484	502,496	542,101	496,244	464,875	429,662	410,267	407,130	409,649	427,317	439,647	4,941,272
(40) Default	3,086	14,071	8,688	32,683	0	0	0	0	0	0	0	0	58,529
(41) TOTAL FT-1 TRANSPORTATION	564,544	188,064	866,438	1,004,840	867,041	718,934	582,551	508,669	482,954	485,824	520,233	588,955	7,379,046
(42) FT-2 TRANSPORTATION													
(43) FT-2 Small	12,639	28,285	39,876	44,734	29,612	18,816	9,189	5,048	5,279	3,247	3,565	5,410	205,700
(44) FT-2 Medium	122,950	237,335	308,086	338,806	276,092	198,707	113,416	67,172	50,975	46,219	50,832	68,766	1,879,355
(45) FT-2 Large LLF	88,340	176,927	357,226	262,270	226,643	165,727	86,224	37,855	20,416	17,434	19,175	33,570	1,491,848
(46) FT-2 Large HLF	45,868	61,193	75,431	82,553	60,278	52,837	42,565	35,108	30,220	29,306	32,165	34,886	582,410
(47) FT-2 Extra Large LLF	8,020	18,445	22,098	25,004	16,587	11,682	6,629	3,467	1,646	1,811	3,249	3,920	122,559
(48) FT-2 Extra Large HLF	28,838	28,545	27,922	44,167	32,040	35,210	32,169	30,519	26,717	23,353	28,533	30,820	368,842
(49) TOTAL FT-2 TRANSPORTATION	306,655	550,730	830,649	797,535	641,252	483,018	290,191	179,169	135,253	121,370	137,518	177,373	4,650,713
(50) Total THROUGHPUT													
(51) Residential Non-Heating	22,908	42,855	58,226	61,500	31,295	26,094	18,018	12,824	10,440	9,901	10,578	13,668	318,306
(52) Residential Non-Heating Low Income	1,636	2,537	3,337	3,630	2,286	2,110	1,451	1,021	824	724	774	1,028	21,358
(53) Residential Heating	1,109,606	2,448,726	3,490,353	3,717,114	2,876,908	2,073,184	1,087,131	594,919	412,329	362,322	380,623	490,598	19,043,813
(54) Residential Heating Low Income	106,303	209,952	282,811	295,762	273,613	217,290	116,926	67,274	46,870	39,870	42,639	54,212	1,753,519
(55) Small C&I	142,801	349,216	529,637	581,211	438,797	276,287	119,708	60,639	48,589	41,905	44,091	60,972	2,693,855
(56) Medium C&I	379,885	690,854	992,552	1,048,532	848,264	601,710	332,503	214,213	174,360	161,745	178,989	237,520	5,861,126
(57) Large LLF	175,414	308,841	592,621	625,881	438,477	310,153	159,833	76,652	45,078	37,999	41,627	84,274	2,796,849
(58) Large HLF	89,735	97,055	150,460	163,518	127,546	111,514	92,474	80,807	69,097	68,486	78,712	85,646	1,215,048
(59) Extra Large LLF	76,526	110,914	169,381	248,452	194,491	126,859	68,823	36,279	23,778	23,452	32,068	60,575	1,171,598
(60) Extra Large HLF	443,128	84,553	556,702	641,632	543,760	513,636	478,018	456,696	448,166	445,308	470,189	486,302	5,568,090
(61) Default	3,086	14,071	8,688	32,683	0	0	0	0	0	0	0	0	58,529
(62) TOTAL THROUGHPUT	2,551,027	4,359,576	6,834,767	7,319,915	5,775,438	4,258,835	2,474,884	1,601,324	1,279,531	1,191,711	1,280,289	1,574,794	40,502,090

Attachment TGS-3

Estimated Deferred Gas Cost Balance with
Revised GCR

Deferred Gas Cost Balances

	Description	Reference	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sen	Oct	Nov-Oct
			Actual 30 (a)	Actual 31 (b)	Actual 31 (c)	Actual 28 (d)	Forecast 31 (e)	Forecast 30 (f)	Forecast 31 (g)	Forecast 30 (h)	Forecast 31 (i)	Forecast 31 (j)	Forecast 30 (k)	Forecast 31 (l)	Forecast 31 (m)
(1)	# of Days in Month		30 (a)	31 (b)	31 (c)	28 (d)	31 (e)	30 (f)	31 (g)	30 (h)	31 (i)	31 (j)	30 (k)	31 (l)	365 (m)
(2)	I. Fixed Cost Deferred														
(3)	Beginning Under/(Over) Recovery		(\$13,924,066)	(\$12,367,836)	(\$19,607,999)	(\$25,222,803)	(\$31,228,960)	(\$34,311,175)	(\$35,060,344)	(\$32,879,904)	(\$29,291,335)	(\$25,184,407)	(\$20,907,508)	(\$16,684,216)	(\$13,924,066)
(4)	Supply Fixed Costs (net of cap rel)	Sch. 2, line (31)	\$8,117,432	\$7,560,197	\$8,368,573	\$8,387,193	\$9,509,862	\$7,399,845	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$93,477,014
(5)	Supply Related System Pressure to DAC		(\$986,458)	(\$1,168,288)	(\$1,266,121)	(\$1,251,721)	(\$2,231,165)	(\$226,605)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$8,335,493)
(6)	Supply Related LNG O & M		\$192,721	\$148,662	\$79,300	\$60,893	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$1,034,791
(7)	NGPMP Credits	Dkt 4770	(\$1,507,649)	(\$6,076,656)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$22,660,798)
(8)	Working Capital	Sch. 4, line (14)	\$51,628	\$46,277	\$51,422	\$51,661	\$52,698	\$51,891	\$51,808	\$51,808	\$51,808	\$51,808	\$51,808	\$51,808	\$616,425
(9)	Total Supply Fixed Costs	Sum(4)-(8)	\$5,867,674	\$5,103,193	\$5,725,525	\$5,740,377	\$5,892,898	\$5,780,634	\$5,769,107	\$5,769,107	\$5,769,107	\$5,769,107	\$5,769,107	\$5,769,107	\$64,131,939
(10)	Supply Fixed - Revenue	Sch. 3, line (10)	\$4,257,530	\$7,684,896	\$11,250,081	\$11,643,870	\$8,843,176	\$6,394,650	\$3,451,898	\$2,059,413	\$1,552,515	\$1,399,422	\$1,472,576	\$1,846,637	\$61,856,665
(11)	Monthly Under/(Over) Recovery	(9) - (10)	\$1,610,144	(\$7,174,704)	(\$5,524,557)	(\$5,903,493)	(\$2,950,279)	(\$614,016)	\$2,317,209	\$3,709,694	\$4,216,591	\$4,369,685	\$4,296,531	\$3,922,470	\$2,275,274
(12)	Prelim. Ending Under/(Over) Recovery	(3) + (11)	(\$12,313,922)	(\$19,542,539)	(\$25,132,556)	(\$31,126,296)	(\$34,179,239)	(\$34,925,191)	(\$32,743,136)	(\$29,170,210)	(\$25,074,744)	(\$20,814,723)	(\$16,610,977)	(\$12,761,746)	(\$13,648,791)
(13)	Month's Average Balance	[(3) + (12)] ÷ 2	(\$13,118,994)	(\$19,955,187)	(\$22,370,277)	(\$28,174,550)	(\$32,704,099)	(\$34,618,183)	(\$33,901,740)	(\$31,025,057)	(\$27,183,040)	(\$22,999,565)	(\$18,759,243)	(\$14,722,981)	(\$13,648,791)
(14)	Interest Rate (BOA Prime minus 200 bps)		5.00%	4.83%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	
(15)	Interest Applied	[(13) x (14)] ÷ 365 x (1)	(\$53,914)	(\$65,460)	(\$90,247)	(\$102,663)	(\$131,936)	(\$135,153)	(\$136,768)	(\$121,125)	(\$109,663)	(\$92,786)	(\$73,238)	(\$59,396)	(\$1,172,350)
(16)	FIXED ENDING UNDER/(OVER) RECOVERY	(12) + (15)	(\$12,367,836)	(\$19,607,999)	(\$25,222,803)	(\$31,228,960)	(\$34,311,175)	(\$35,060,344)	(\$32,879,904)	(\$29,291,335)	(\$25,184,407)	(\$20,907,508)	(\$16,684,216)	(\$12,821,142)	(\$12,821,142)
(17)	II. Variable Cost Deferred														
(18)	Beginning Under/(Over) Recovery		\$11,777,674	\$15,178,748	\$22,117,054	\$52,497,527	\$55,627,630	\$50,690,150	\$43,983,962	\$35,727,538	\$31,341,340	\$28,422,429	\$26,230,115	\$23,709,915	\$11,777,674
(19)	Variable Supply Costs	Sch. 2, line (70)	\$10,283,052	\$21,868,143	\$51,429,463	\$26,483,952	\$12,561,155	\$5,793,537	\$3,777,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180	\$143,060,989
(20)	Supply Related System Pressure to DAC														\$0
(21)	Supply Related LNG O & M	Dkt 4770	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$25,187	\$302,244
(22)	Inventory Financing - LNG	Sch. 5, line (22)	\$44,779	\$43,049	\$26,870	\$19,064	\$16,018	\$17,039	\$20,701	\$21,392	\$22,273	\$23,208	\$23,963	\$27,777	\$306,131
(23)	Inventory Financing - UG	Sch. 5, line (12)	\$86,452	\$73,062	\$56,023	\$44,543	\$49,568	\$50,762	\$60,634	\$63,870	\$63,904	\$63,904	\$70,000	\$81,497	\$764,220
(24)	Working Capital	Sch. 4, line (28)	\$74,449	\$158,325	\$372,349	\$191,744	\$90,943	\$41,945	\$24,455	\$15,614	\$12,737	\$13,918	\$13,637	\$25,645	\$1,035,762
(25)	Total Supply Variable Costs	Sum(19)-(24)	\$10,513,918	\$22,167,766	\$51,909,893	\$26,764,490	\$12,742,870	\$5,928,471	\$3,508,688	\$2,282,687	\$1,883,363	\$2,048,537	\$2,016,375	\$3,702,286	\$145,469,346
(26)	Supply Variable - Revenue	Sch. 3, line (23)	\$7,186,482	\$15,305,811	\$21,679,624	\$23,831,025	\$17,894,374	\$12,819,108	\$11,925,577	\$6,799,552	\$4,922,582	\$4,350,870	\$4,633,871	\$6,017,842	\$137,366,717
(27)	Monthly Under/(Over) Recovery	(25) - (26)	\$3,327,437	\$6,861,956	\$30,230,269	\$2,933,466	(\$5,151,504)	(\$6,890,637)	(\$8,416,889)	(\$4,516,865)	(\$3,039,219)	(\$2,302,333)	(\$2,617,496)	(\$2,314,556)	\$8,102,629
(28)	Prelim. Ending Under/(Over) Recovery	(18) + (27)	\$15,105,110	\$22,040,704	\$52,347,323	\$55,430,993	\$50,476,126	\$43,799,513	\$35,567,073	\$31,210,673	\$28,302,121	\$26,120,096	\$23,612,620	\$21,394,359	\$19,880,302
(29)	Month's Average Balance	[(18) + (28)] ÷ 2	\$13,441,392	\$18,609,726	\$37,232,189	\$53,964,260	\$53,051,878	\$47,244,832	\$39,775,518	\$33,469,105	\$29,821,730	\$27,271,263	\$24,921,367	\$22,521,137	\$19,880,302
(30)	Interest Rate (BOA Prime minus 200 bps)		5.00%	4.83%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	
(31)	Interest Applied	[(29) x (30)] ÷ 365 x (1)	\$55,239	\$76,351	\$150,204	\$196,637	\$214,024	\$184,449	\$160,464	\$120,308	\$110,019	\$97,296	\$90,981	\$1,586,639	
(32)	Gas Procurement Incentive/(penalty)		\$18,399	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$18,399	
(33)	VARIABLE ENDING UNDER/(OVER) RECOVERY	(28) + (31) + (32)	\$15,178,748	\$22,117,054	\$52,497,527	\$55,627,630	\$50,690,150	\$43,983,962	\$35,727,538	\$31,341,340	\$28,422,429	\$26,230,115	\$23,709,915	\$21,485,340	\$21,485,340
(34)	GCR Deferred Summary														
(35)	Beginning Under/(Over) Recovery	(3) + (18)	(\$2,146,392)	\$2,810,913	\$2,509,055	\$27,274,724	\$24,398,670	\$16,378,975	\$8,923,618	\$2,847,634	\$2,050,004	\$3,238,022	\$5,322,607	\$7,025,700	(\$2,146,392)
(36)	Gas Costs	Sum(4)-(6)-(19)-(21)	\$17,631,933	\$28,433,902	\$58,636,403	\$33,705,505	\$19,934,191	\$13,055,116	\$10,627,847	\$9,406,759	\$9,009,397	\$9,172,455	\$9,133,723	\$10,792,315	\$229,539,545
(37)	Inventory Finance	(22) + (23)	\$131,230	\$116,111	\$82,893	\$63,607	\$65,585	\$67,802	\$81,335	\$85,262	\$86,177	\$87,112	\$93,963	\$109,274	\$1,070,351
(38)	Working Capital	(8) + (24)	\$126,078	\$204,603	\$423,771	\$245,405	\$143,641	\$93,836	\$76,263	\$67,422	\$64,545	\$65,726	\$65,445	\$77,453	\$1,652,187
(39)	NGPMP Credits	(7)	(\$1,507,649)	(\$6,076,656)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$1,507,649)	(\$22,660,798)
(40)	Total Costs	Sum(36)-(39)	\$16,881,592	\$22,677,959	\$57,635,417	\$32,504,867	\$18,635,768	\$11,709,105	\$9,277,795	\$8,051,794	\$7,652,469	\$7,817,644	\$7,785,482	\$9,471,392	\$209,601,285
(41)	Revenue	(10) + (26)	\$11,444,011	\$22,990,707	\$32,929,705	\$35,474,895	\$26,737,551	\$19,213,758	\$15,377,475	\$8,858,965	\$6,475,097	\$5,750,292	\$6,706,446	\$7,864,478	\$199,223,382
(42)	Monthly Under/(Over) Recovery	(40) - (41)	\$4,937,580	(\$312,748)	\$24,705,712	(\$2,970,028)	(\$8,101,783)	(\$7,504,653)	(\$6,099,680)	(\$807,171)	\$1,177,372	\$2,067,352	\$1,069,035	\$1,606,914	\$10,377,903
(43)	Prelim. Ending Under/(Over) Recovery	(35) + (42)	\$2,791,189	\$2,498,164	\$27,214,768	\$24,304,697	\$16,296,887	\$8,874,322	\$2,823,937	\$2,040,463	\$3,227,377	\$5,305,374	\$7,001,642	\$8,632,614	\$130,373,903
(44)	Month's Average Balance	[(35) + (43)] ÷ 2	\$322,398	\$2,654,539	\$14,861,912	\$25,789,710	\$20,347,779	\$12,626,648	\$5,873,778	\$2,444,048	\$2,638,691	\$4,271,698	\$6,162,125	\$7,829,157	\$130,373,903
(45)	Interest Rate (BOA Prime minus 200 bps)		5.00%	4.83%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	
(46)	Interest Applied	(15) + (31)	\$13,325	\$10,891	\$59,957	\$93,973	\$82,088	\$49,296	\$23,696	\$9,542	\$10,645	\$17,233	\$24,058	\$31,585	\$414,288
(47)	Gas Purchase Plan Incentives/(Penalties)	(32)	\$18,399	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$18,399	
(48)	ENDING UNDER/(OVER) RECOVERY W/ INTEREST	(43) + (46) + (47)	\$2,810,913	\$2,509,055	\$27,274,724	\$24,398,670	\$16,378,975	\$8,923,618	\$2,847,634	\$2,050,004	\$3,238,022	\$5,322,607	\$7,025,700	\$8,664,198	\$8,664,198

Supply Estimates Actuals for Filing

	<u>Nov</u> <u>Actual</u> (a)	<u>Dec</u> <u>Actual</u> (b)	<u>Jan</u> <u>Actual</u> (c)	<u>Feb</u> <u>Actual</u> (d)	<u>Mar</u> <u>Forecast</u> (e)	<u>Apr</u> <u>Forecast</u> (f)	<u>May</u> <u>Forecast</u> (g)	<u>Jun</u> <u>Forecast</u> (h)	<u>Jul</u> <u>Forecast</u> (i)	<u>Aug</u> <u>Forecast</u> (j)	<u>Sep</u> <u>Forecast</u> (k)	<u>Oct</u> <u>Forecast</u> (l)	<u>Nov-Oct</u> <u>Forecast</u> (m)
<u>Description</u>	<u>Reference</u>												
(1) SUPPLY FIXED COSTS - Pipeline Delivery													
(2) AGT M3	\$438,710	\$440,364	\$442,331	\$442,331	\$174,487	\$174,487	\$174,487	\$174,487	\$174,487	\$174,487	\$174,487	\$174,487	\$3,159,631
(3) AIM	\$927,625	\$925,463	\$933,613	\$914,553	\$781,498	\$781,498	\$781,498	\$781,498	\$781,498	\$781,498	\$781,498	\$781,498	\$9,953,238
(4) Dawn via PNGTS	\$1,294,033	\$1,325,385	\$1,300,881	\$1,215,733	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$1,059,382	\$13,611,090
(5) Dawn via Waddington	\$10,192	\$10,176	\$10,184	\$9,700	\$22,061	\$22,061	\$22,061	\$22,061	\$22,061	\$22,061	\$22,061	\$22,061	\$216,741
(6) EGTS	\$9,193	\$9,193	\$9,193	\$9,379	\$9,421	\$9,421	\$9,421	\$9,421	\$9,421	\$9,421	\$9,421	\$9,421	\$112,323
(7) Manchester Lateral	\$262,800	\$262,800	\$262,800	\$262,800	\$216,276	\$216,276	\$216,276	\$216,276	\$216,276	\$216,276	\$216,276	\$216,276	\$2,781,409
(8) Niagara	\$6,241	\$6,224	\$6,232	\$5,716	\$5,974	\$5,974	\$5,974	\$5,974	\$5,974	\$5,974	\$5,974	\$5,974	\$72,204
(9) TCO (Pool)	\$894,034	\$165,850	\$894,754	\$894,394	\$849,526	\$849,526	\$849,526	\$849,526	\$849,526	\$849,526	\$849,526	\$849,526	\$9,645,239
(10) TETCO CDS Long Haul	\$1,663,179	\$1,669,795	\$1,677,480	\$1,734,486	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$1,448,740	\$18,334,862
(11) TETCO SCT Long Haul	\$32,045	\$31,997	\$31,992	\$33,019	\$25,970	\$25,970	\$25,970	\$25,970	\$25,970	\$25,970	\$25,970	\$25,970	\$336,814
(13) TGP ConneXion	\$264,274	\$264,088	\$264,181	\$264,181	\$221,980	\$221,980	\$221,980	\$221,980	\$221,980	\$221,980	\$221,980	\$221,980	\$2,832,564
(12) TGP Long Haul	\$512,711	\$512,242	\$512,477	\$469,865	\$412,761	\$412,761	\$412,761	\$412,761	\$412,761	\$412,761	\$412,761	\$412,761	\$5,309,380
(14) Transco	\$12,559	\$12,791	\$12,791	\$12,097	\$12,238	\$12,238	\$12,238	\$12,238	\$12,238	\$12,238	\$12,238	\$12,238	\$148,142
(15) AMA Credits	(\$239,642)	(\$218,890)	(\$230,427)	(\$211,215)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$243,888)	(\$2,851,278)
(16) Less Credits from Mkter Releases*	(\$931,041)	(\$924,787)	(\$990,032)	(\$869,191)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$3,715,051)
(17) STORAGE FIXED COSTS - Facilities													
(18) Columbia FSS	\$23,219	(\$11,940)	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$23,219	\$243,466
(19) Exeter LNG	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(20) Providence LNG	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$331,020	\$3,972,240
(21) Tennessee FSMA	\$39,253	\$39,284	\$39,253	\$35,969	\$37,611	\$37,611	\$37,611	\$37,611	\$37,611	\$37,611	\$37,611	\$37,611	\$454,647
(22) Tetco FSS1	\$2,481	\$2,496	\$2,470	\$2,625	\$3,917	\$3,917	\$3,917	\$3,917	\$3,917	\$3,917	\$3,917	\$3,917	\$41,409
(23) Tetco SS1	\$133,721	\$133,086	\$133,738	\$140,535	\$159,773	\$159,773	\$159,773	\$159,773	\$159,773	\$159,773	\$159,773	\$159,773	\$1,819,262
(24) EGTS GSS	\$57,381	\$57,381	\$57,381	\$57,381	\$80,239	\$80,239	\$80,239	\$80,239	\$80,239	\$80,239	\$80,239	\$80,239	\$871,438
(25) EGTS GSSTE	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$73,941	\$887,291
(26) Less Credits from Mkter Releases	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(27) STORAGE FIXED COSTS - Delivery													
(28) Storage Delivery	\$490,019	\$444,259	\$473,286	\$473,240	\$576,035	\$532,120	\$532,120	\$532,120	\$532,120	\$532,120	\$532,120	\$532,120	\$6,181,682
(29) LNG	\$764,225	\$770,891	\$770,891	\$750,892	\$823,842	\$823,842	\$823,842	\$823,842	\$823,842	\$823,842	\$823,842	\$823,842	\$9,647,637
(30) Confidential Pipeline and Peaking Supplies	<u>\$1,045,261</u>	<u>\$1,227,091</u>	<u>\$1,324,924</u>	<u>\$1,310,524</u>	<u>\$2,403,839</u>	<u>\$331,736</u>	<u>\$294,543</u>	<u>\$294,543</u>	<u>\$294,543</u>	<u>\$294,543</u>	<u>\$294,543</u>	<u>\$294,543</u>	<u>\$9,410,632</u>
(31) TOTAL FIXED COSTS	Sum[(2):(30)]	\$8,117,432	\$7,560,197	\$8,368,573	\$8,387,193	\$9,509,862	\$7,393,845	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$93,477,014

Supply Estimates Actuals for Filing

		<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov-Oct</u>
		<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
<u>Description</u>	<u>Reference</u>													
(32) VARIABLE COMMODITY COSTS														
(33) AIM at Ramapo		\$0	\$0	\$0	\$0	\$43,019	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$43,019
(34) Beverly		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(35) Dawn via IGTS		\$0	\$0	\$0	\$0	\$290	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$290
(36) Dawn via PNGTS		\$0	\$0	\$0	\$0	\$143,850	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$143,850
(37) Dracut		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(38) EGTS SP		\$0	\$0	\$0	\$0	\$39,701	\$37,817	\$37,746	\$39,064	\$44,554	\$45,085	\$38,298	\$38,226	\$320,490
(39) Millennium		\$0	\$0	\$0	\$0	\$103,695	\$0	\$0	\$0	\$635,518	\$0	\$0	\$0	\$739,213
(40) Niagara		\$0	\$0	\$0	\$0	\$83,968	\$0	\$0	\$0	\$92,384	\$94,684	\$0	\$0	\$271,036
(41) TCO Appalachia		\$0	\$0	\$0	\$0	\$2,552,483	\$96,463	\$131,024	\$99,654	\$0	\$0	\$0	\$59,242	\$2,938,865
(42) Tetco M2 CDS		\$0	\$0	\$0	\$0	\$2,649,932	\$180,963	\$1,061,807	\$1,264,395	\$699,794	\$1,476,410	\$2,079,880	\$2,727,351	\$12,140,533
(43) Tetco M2 SCT		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(44) Tetco M3		\$0	\$0	\$0	\$0	\$929,114	\$4,025,200	\$2,415,871	\$0	\$0	\$0	\$0	\$1,180,118	\$8,550,302
(45) TGP Z4 Cnx		\$0	\$0	\$0	\$0	\$774,199	\$635,385	\$692,577	\$745,869	\$244,373	\$277,820	\$567,180	\$736,165	\$4,673,569
(46) TGP Z4 LH		\$0	\$0	\$0	\$0	\$1,177,580	\$323,185	\$59,775	\$0	\$0	\$0	\$742	\$461,225	\$2,022,507
(47) Transco Leidy		\$0	\$0	\$0	\$0	\$5,550	\$5,141	\$5,082	\$5,286	\$6,110	\$6,164	\$5,161	\$5,175	\$43,671
(48) Winter Liquid		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(49) Confidential Pipeline and Peaking Supplies		\$0	\$0	\$0	\$0	\$24,607	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$24,607
(50) Variable Transportation Costs		\$0	\$0	\$0	\$0	\$426,514	\$227,902	\$399,530	\$128,821	\$101,528	\$136,839	\$159,522	\$500,007	\$2,080,663
(51) Total Pipeline Commodity Charges	Sum[(33):(50)]	\$9,019,647	\$18,908,372	\$43,388,609	\$28,683,446	\$8,954,501	\$5,532,055	\$4,803,412	\$2,283,090	\$1,824,261	\$2,037,003	\$2,850,784	\$5,707,508	\$133,992,688
(52) INJECTIONS & HEDGING IMPACT														
(53) Hedging		\$1,478,640	(\$183,185)	(\$120,559)	(\$9,314,068)	\$2,239,789	\$592,824	\$597,365	\$460,535	\$71,808	\$25,087	\$56,898	\$123,495	(\$3,971,371)
(54) Less: Costs of Injections		\$0	\$0	\$0	\$0	\$0	(\$667,010)	(\$2,126,148)	(\$678,651)	(\$226,400)	(\$225,712)	(\$1,104,233)	(\$2,368,936)	(\$7,397,090)
(55) TOTAL VARIABLE SUPPLY COSTS	Sum[(51):(54)]	\$10,498,287	\$18,725,187	\$43,268,049	\$19,369,378	\$11,194,290	\$5,457,869	\$3,274,628	\$2,064,974	\$1,669,669	\$1,836,379	\$1,803,449	\$3,462,066	\$122,624,226
(56) TOTAL VARIABLE STORAGE COSTS		\$637,741	\$2,222,426	\$5,427,672	\$2,726,510	\$1,366,865	\$335,668	\$103,084	\$91,650	\$89,593	\$85,942	\$80,139	\$80,113	\$13,247,403
(57) TOTAL VARIABLE COSTS	(55) + (56)	\$11,136,028	\$20,947,613	\$48,695,721	\$22,095,888	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180	\$135,871,629
(58) TOTAL SUPPLY COSTS	(31) + (57)	\$19,253,460	\$28,507,810	\$57,064,294	\$30,483,081	\$22,071,017	\$13,187,382	\$10,734,364	\$9,513,276	\$9,115,914	\$9,278,973	\$9,240,240	\$10,898,832	\$229,348,643

Supply Estimates Actuals for Filing

		<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov-Oct</u>
		<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
<u>Description</u>	<u>Reference</u>													
(59) Storage Costs for FT-2 Calculation														
(60) Total Managed and Storage Costs		\$2,732,194	\$2,843,303	\$3,003,972	\$2,986,088	\$4,231,394	\$2,115,377	\$2,115,377	\$2,115,377	\$2,115,377	\$2,115,377	\$2,115,377	\$2,115,377	\$30,604,586
(61) Supply Related System Pressure to DAC		(\$986,458)	(\$1,168,288)	(\$1,266,121)	(\$1,251,721)	(\$2,231,165)	(\$226,605)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$8,335,493)
(62) Inventory Financing		\$131,230	\$116,111	\$82,893	\$63,607	\$65,585	\$67,802	\$81,335	\$85,262	\$86,177	\$87,112	\$93,963	\$109,274	\$1,070,351
(63) Supply Related LNG O&M Costs		\$192,721	\$148,662	\$79,300	\$60,893	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$69,152	\$1,034,791
(64) Working Capital Requirement		<u>\$12,605</u>	<u>\$12,094</u>	<u>\$12,548</u>	<u>\$12,523</u>	<u>\$14,442</u>	<u>\$13,637</u>	<u>\$13,823</u>	<u>\$13,823</u>	<u>\$13,823</u>	<u>\$13,823</u>	<u>\$13,823</u>	<u>\$13,823</u>	\$160,788
(65) TOTAL FT-2 STORAGE FIXED COSTS	Sum[(60):(64)]	\$2,082,291	\$1,951,882	\$1,912,592	\$1,871,390	\$2,149,408	\$2,039,363	\$2,078,831	\$2,082,758	\$2,083,673	\$2,084,608	\$2,091,458	\$2,106,769	\$24,535,023
(66) System Storage MDQ (Dth)		196,220	195,510	194,840	195,090	196,390	196,390	196,390	196,390	196,390	196,390	196,390	196,390	\$2,352,783
(67) FT-2 Storage Cost per MDQ (Dth)	(65) ÷ (66)	\$10.6120	\$9.9835	\$9.8162	\$9.5924	\$10.9446	\$10.3842	\$10.5852	\$10.6052	\$10.6099	\$10.6146	\$10.6495	\$10.7275	\$10.4281
(68) Pipeline Variable	(57)	\$11,136,028	\$20,947,613	\$48,695,721	\$22,095,888	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180	\$135,871,629
(69) Less Non-firm Gas Costs		(\$139,070)	(\$339,162)	(\$500,043)	(\$338,843)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,317,119)
(70) Mkter Over-takes/Undertakes		(\$769,945)	\$1,116,521	\$3,317,254	\$4,380,689	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$8,044,519
(71) Less Mkter FT-2 Daily weather true-up		<u>\$56,039</u>	<u>\$143,171</u>	<u>(\$83,469)</u>	<u>\$346,218</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	\$461,959
(72) TOTAL FIRM COMMODITY COSTS	Sum[(68):(71)]	\$10,283,052	\$21,868,143	\$51,429,463	\$26,483,952	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180	\$143,060,989

GCR Revenue

		<u>Nov</u> <u>Actual</u>	<u>Dec</u> <u>Actual</u>	<u>Jan</u> <u>Actual</u>	<u>Feb</u> <u>Actual</u>	<u>Mar</u> <u>Forecast</u>	<u>Apr</u> <u>Forecast</u>	<u>May</u> <u>Forecast</u>	<u>Jun</u> <u>Forecast</u>	<u>Jul</u> <u>Forecast</u>	<u>Aug</u> <u>Forecast</u>	<u>Sep</u> <u>Forecast</u>	<u>Oct</u> <u>Forecast</u>	<u>Nov-Oct</u>
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
<u>Description</u>	<u>Reference</u>													
(1) <u>I. Fixed Cost Revenue</u>														
(2) (a) Low Load dth	Sch. 6, Sum[(24):(28), (30)]	1,608,405	3,513,086	5,013,283	5,361,309	4,187,850	2,987,373	1,545,092	863,370	619,112	547,059	577,996	758,645	27,582,580
(3) Fixed Cost Factor	(4) ÷ (2)	\$2.4178	\$2.0321	\$2.0281	\$2.0297	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276	\$2.0276
(4) Low Load Revenue		\$3,888,755	\$7,138,796	\$10,167,512	\$10,881,677	\$8,491,412	\$6,057,289	\$3,132,876	\$1,750,596	\$1,255,331	\$1,109,233	\$1,171,963	\$1,538,252	\$56,583,690
(5) (b) High Load dth	Sch. 6, Sum[(22), (23), (29), (31)]	71,422	107,696	124,397	156,231	79,296	69,509	57,050	50,115	42,212	37,459	44,541	49,822	889,751
(6) Fixed Cost Factor	(7) ÷ (5)	\$1.8028	\$1.4740	\$1.4753	\$1.4813	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718	\$1.4718
(7) High Load Revenue		\$128,761	\$158,745	\$183,523	\$231,431	\$116,707	\$102,304	\$83,965	\$73,759	\$62,128	\$55,132	\$65,555	\$73,328	\$1,335,338
(8) Sub-total throughput Dth	(2) + (5)	1,679,827	3,620,782	5,137,680	5,517,540	4,267,145	3,056,882	1,602,141	913,486	661,324	584,517	622,537	808,467	28,472,331
(9) FT-2 Storage Revenue from marketers		\$240,014	\$387,355	\$899,046	\$530,762	\$235,057	\$235,057	\$235,057	\$235,057	\$235,057	\$235,057	\$235,057	\$235,057	\$3,937,637
(10) TOTAL FIXED REVENUE	(4) + (7) + (9)	\$4,257,530	\$7,684,896	\$11,250,081	\$11,643,870	\$8,843,176	\$6,394,650	\$3,451,898	\$2,059,413	\$1,552,515	\$1,399,422	\$1,472,576	\$1,846,637	\$61,856,665
(11) <u>II. Variable Cost Revenue</u>														
(12) (a) Firm Sales dth	(8)	1,679,827	3,620,782	5,137,680	5,517,540	4,267,145	3,056,882	1,602,141	913,486	661,324	584,517	622,537	808,467	28,472,331
(13) Variable Supply Cost Factor	(14) ÷ (12)	\$4.2651	\$4.2025	\$4.1934	\$4.1984	\$4.1935	\$4.1935	\$7.4435	\$7.4435	\$7.4435	\$7.4435	\$7.4435	\$7.4435	\$7.4435
(14) Variable Supply Revenue		\$7,164,602	\$15,216,372	\$21,544,512	\$23,164,773	\$17,894,374	\$12,819,108	\$11,925,577	\$6,799,552	\$4,922,582	\$4,350,870	\$4,633,871	\$6,017,842	\$136,454,036
(15) (b) TSS Sales dth	Sch. 6, line (20)	8,414	17,504	24,664	30,289	0	0	0	0	0	0	0	0	\$80,871
(16) TSS Surcharge Factor	Company's website	\$0.0194	\$0.0179	\$0.2729	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
(17) TSS Surcharge Revenue	(16) x (17)	\$163	\$313	\$6,731	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$7,207
(18) (c) Default Sales dth	Sch. 6, line (60)	3,086	14,071	8,688	32,683	0	0	0	0	0	0	0	0	58,529
(19) Variable Supply Cost Factor	(20) ÷ (18)	\$7.04	\$6.33	\$14.78	\$20.39	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(20) Variable Supply Revenue		\$21,716	\$89,125	\$128,381	\$666,252	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$905,474
(21) (d) Deferred Responsibility		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(22) (e) FT-1 Storage and Peaking														
(23) TOTAL VARIABLE REVENUE	(14)+(17)+(20)+(21)	\$7,186,482	\$15,305,811	\$21,679,624	\$23,831,025	\$17,894,374	\$12,819,108	\$11,925,577	\$6,799,552	\$4,922,582	\$4,350,870	\$4,633,871	\$6,017,842	\$137,366,717
(24) Total GAS COST REVENUE (w/o FT-2)	(10) + (23)	\$11,444,011	\$22,990,707	\$32,929,705	\$35,474,895	\$26,737,551	\$19,213,758	\$15,377,475	\$8,858,965	\$6,475,097	\$5,750,292	\$6,106,446	\$7,864,478	\$199,223,382

Schedule 4

Page 1 of 1

WORKING CAPITAL

		<u>Nov</u> <u>Actual</u> (a)	<u>Dec</u> <u>Actual</u> (b)	<u>Jan</u> <u>Actual</u> (c)	<u>Feb</u> <u>Actual</u> (d)	<u>Mar</u> <u>Forecast</u> (e)	<u>Apr</u> <u>Forecast</u> (f)	<u>May</u> <u>Forecast</u> (g)	<u>Jun</u> <u>Forecast</u> (h)	<u>Jul</u> <u>Forecast</u> (i)	<u>Aug</u> <u>Forecast</u> (j)	<u>Sep</u> <u>Forecast</u> (k)	<u>Oct</u> <u>Forecast</u> (l)	<u>Nov-Oct</u> (m)
	<u>Description</u>													
	<u>Reference</u>													
(1)	Supply Fixed Costs	Sch. 1, line (4)	\$8,117,432	\$7,560,197	\$8,368,573	\$8,387,193	\$9,509,862	\$7,393,845	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$7,356,652	\$93,477,014
(2)	Less System Pressure to DAC	Sch. 1, line (5)	(\$986,458)	(\$1,168,288)	(\$1,266,121)	(\$1,251,721)	(\$2,231,165)	(\$226,605)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)
(3)	Total Adjustments	(2)	(\$986,458)	(\$1,168,288)	(\$1,266,121)	(\$1,251,721)	(\$2,231,165)	(\$226,605)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$200,856)	(\$8,335,493)
(4)	Allowable Working Capital Costs	(1) + (3)	\$7,130,974	\$6,391,909	\$7,102,452	\$7,135,473	\$7,278,697	\$7,167,240	\$7,155,796	\$7,155,796	\$7,155,796	\$7,155,796	\$7,155,796	\$85,141,521
(5)	Number of Days Lag	Dkt 4770	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	
(6)	Working Capital Requirement	[(4) x (5)] ÷ 365	\$643,155	\$576,498	\$640,583	\$643,561	\$656,479	\$646,426	\$645,394	\$645,394	\$645,394	\$645,394	\$645,394	\$645,394
(7)	Cost of Capital	Dkt 4770	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
(8)	Return on Working Capital Requiren	(6) x (7)	\$43,542	\$39,029	\$43,367	\$43,569	\$44,444	\$43,763	\$43,693	\$43,693	\$43,693	\$43,693	\$43,693	\$43,693
(9)	Cost of Debt (Long Term Debt + Shc	Dkt 4770	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%
(10)	Interest Expense	(6) x (9)	\$13,120	\$11,761	\$13,068	\$13,129	\$13,392	\$13,187	\$13,166	\$13,166	\$13,166	\$13,166	\$13,166	\$13,166
(11)	Taxable Income	(8) - (10)	\$30,421	\$27,268	\$30,300	\$30,440	\$31,051	\$30,576	\$30,527	\$30,527	\$30,527	\$30,527	\$30,527	\$30,527
(12)	1 - Combined Tax Rate	Dkt 4770	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79
(13)	Return and Tax Requirement	(11) ÷ (12)	\$38,508	\$34,517	\$38,354	\$38,532	\$39,306	\$38,704	\$38,642	\$38,642	\$38,642	\$38,642	\$38,642	\$38,642
(14)	Supply Fixed Working Capital Re	(10) + (13)	\$51,628	\$46,277	\$51,422	\$51,661	\$52,698	\$51,891	\$51,808	\$51,808	\$51,808	\$51,808	\$51,808	\$616,425
(15)	Supply Variable Costs	Sch. 1, line (19)	\$10,283,052	\$21,868,143	\$51,429,463	\$26,483,952	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180
(16)	Less: Bal. Related Syst. Pressure Cor	Sch. 1, line (20)												
(17)	Total Adjustments	(16)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
(18)	Allowable Working Capital Costs	(15) + (17)	\$10,283,052	\$21,868,143	\$51,429,463	\$26,483,952	\$12,561,155	\$5,793,537	\$3,377,712	\$2,156,624	\$1,759,262	\$1,922,321	\$1,883,588	\$3,542,180
(19)	Number of Days Lag	Dkt 4770	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92
(20)	Working Capital Requirement	[(18) x (19)] ÷ 365	\$927,447	\$1,972,327	\$4,638,515	\$2,388,635	\$1,132,913	\$522,529	\$304,642	\$194,510	\$158,671	\$173,378	\$169,884	\$319,475
(21)	Cost of Capital	Dkt 4770	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
(22)	Return on Working Capital Requiren	(20) x (21)	\$62,788	\$133,527	\$314,027	\$161,711	\$76,698	\$35,375	\$20,624	\$13,168	\$10,742	\$11,738	\$11,501	\$21,628
(23)	Cost of Debt (Long Term Debt + Shc	Dkt 4770	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%
(24)	Interest Expense	(20) x (23)	\$18,920	\$40,235	\$94,626	\$48,728	\$23,111	\$10,660	\$6,215	\$3,968	\$3,237	\$3,537	\$3,466	\$6,517
(25)	Taxable Income	(22) - (24)	\$43,868	\$93,291	\$219,402	\$112,982	\$53,587	\$24,716	\$14,410	\$9,200	\$7,505	\$8,201	\$8,036	\$15,111
(26)	1 - Combined Tax Rate	Dkt 4770	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79
(27)	Return and Tax Requirement	(25) ÷ (26)	\$55,529	\$118,090	\$277,724	\$143,016	\$67,831	\$31,286	\$18,240	\$11,646	\$9,500	\$10,381	\$10,172	\$19,128
(28)	Supply Variable Working Capital	(24) + (27)	\$74,449	\$158,325	\$372,349	\$191,744	\$90,943	\$41,945	\$24,455	\$15,614	\$12,737	\$13,918	\$13,637	\$25,645

INVENTORY FINANCE

		<u>Nov</u> <u>Actual</u> (a)	<u>Dec</u> <u>Actual</u> (b)	<u>Jan</u> <u>Actual</u> (c)	<u>Feb</u> <u>Actual</u> (d)	<u>Mar</u> <u>Forecast</u> (e)	<u>Apr</u> <u>Forecast</u> (f)	<u>May</u> <u>Forecast</u> (g)	<u>Jun</u> <u>Forecast</u> (h)	<u>Jul</u> <u>Forecast</u> (i)	<u>Aug</u> <u>Forecast</u> (j)	<u>Sep</u> <u>Forecast</u> (k)	<u>Oct</u> <u>Forecast</u> (l)	<u>Nov-Oct</u> (m)
<u>Description</u>	<u>Reference</u>													
(1) Storage Inventory Balance		\$11,199,806	\$9,642,526	\$7,663,995	\$6,409,877	\$7,409,829	\$7,588,430	\$9,064,131	\$9,547,908	\$9,553,012	\$9,553,012	\$10,464,244	\$12,182,909	
(2) Monthly Storage Deferral/Amortization		<u>\$1,723,779</u>	<u>\$1,279,506</u>	<u>\$710,838</u>	<u>\$248,795</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	
(3) Subtotal	(1) + (2)	\$12,923,585	\$10,922,032	\$8,374,833	\$6,658,671	\$7,409,829	\$7,588,430	\$9,064,131	\$9,547,908	\$9,553,012	\$9,553,012	\$10,464,244	\$12,182,909	
(4) Cost of Capital	Dkt 4770	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	
(5) Return on Working Capital Requirement	(3) x (4)	\$874,927	\$739,422	\$566,976	\$450,792	\$501,645	\$513,737	\$613,642	\$646,393	\$646,739	\$646,739	\$708,429	\$824,783	\$7,734,224
(6) Weighted Cost of Debt	Dkt 4770	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	
(7) Interest Charges Financed	(3) x (6)	\$263,641	\$222,809	\$170,847	\$135,837	\$151,161	\$154,804	\$184,908	\$194,777	\$194,881	\$194,881	\$213,471	\$248,531	\$2,330,549
(8) Taxable Income	(5) - (7)	\$611,286	\$516,612	\$396,130	\$314,955	\$350,485	\$358,933	\$428,733	\$451,616	\$451,857	\$451,857	\$494,959	\$576,252	
(9) 1 - Combined Tax Rate	Dkt 4770	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(10) Return and Tax Requirement	(8) ÷ (9)	\$773,779	\$653,939	\$501,430	\$398,677	\$443,652	\$454,345	\$542,701	\$571,666	\$571,972	\$571,972	\$626,530	\$729,432	\$6,840,095
(11) Working Capital Requirement	(7) + (10)	\$1,037,420	\$876,749	\$672,276	\$534,514	\$594,812	\$609,149	\$727,609	\$766,443	\$766,853	\$766,853	\$840,001	\$977,964	\$9,170,644
(12) Monthly Average	(11) ÷ 12	\$86,452	\$73,062	\$56,023	\$44,543	\$49,568	\$50,762	\$60,634	\$63,870	\$63,904	\$63,904	\$70,000	\$81,497	\$764,220
(13) LNG Inventory Balance		\$6,693,909	\$6,435,308	\$4,016,764	\$2,849,913	\$2,394,473	\$2,547,214	\$3,094,578	\$3,197,802	\$3,329,505	\$3,469,275	\$3,582,137	\$4,152,295	
(14) Cost of Capital	Dkt 4770	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	
(15) Return on Working Capital Requirement	(13) x (14)	\$453,178	\$435,670	\$271,935	\$192,939	\$162,106	\$172,446	\$209,503	\$216,491	\$225,407	\$234,870	\$242,511	\$281,110	\$3,098,167
(16) Weighted Cost of Debt	Dkt 4770	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	
(17) Interest Charges Financed	(13) x (16)	\$136,556	\$131,280	\$81,942	\$58,138	\$48,847	\$51,963	\$63,129	\$65,235	\$67,922	\$70,773	\$73,076	\$84,707	\$933,569
(18) Taxable Income	(15) - (17)	\$316,622	\$304,390	\$189,993	\$134,801	\$113,259	\$120,483	\$146,374	\$151,256	\$157,486	\$164,097	\$169,435	\$196,404	
(19) 1 - Combined Tax Rate	Dkt 4770	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(20) Return and Tax Requirement	(18) ÷ (19)	\$400,787	\$385,304	\$240,497	\$170,634	\$143,365	\$152,510	\$185,283	\$191,463	\$199,349	\$207,717	\$214,475	\$248,612	\$2,739,997
(21) Working Capital Requirement	(17) + (20)	\$537,343	\$516,584	\$322,439	\$228,772	\$192,212	\$204,474	\$248,412	\$256,698	\$267,271	\$278,491	\$287,550	\$333,319	\$3,673,566
(22) Monthly Average	(21) ÷ 12	\$44,779	\$43,049	\$26,870	\$19,064	\$16,018	\$17,039	\$20,701	\$21,392	\$22,273	\$23,208	\$23,963	\$27,777	\$306,131
(23) TOTAL GCR Inventory Financing Costs	(12) + (22)	\$131,230	\$116,111	\$82,893	\$63,607	\$65,585	\$67,802	\$81,335	\$85,262	\$86,177	\$87,112	\$93,963	\$109,274	\$1,070,351

Actual Dth Usage for Filing

	<u>Nov</u> <u>Actual</u>	<u>Dec</u> <u>Actual</u>	<u>Jan</u> <u>Actual</u>	<u>Feb</u> <u>Actual</u>	<u>Mar</u> <u>Forecast</u>	<u>Apr</u> <u>Forecast</u>	<u>May</u> <u>Forecast</u>	<u>Jun</u> <u>Forecast</u>	<u>Jul</u> <u>Forecast</u>	<u>Aug</u> <u>Forecast</u>	<u>Sep</u> <u>Forecast</u>	<u>Oct</u> <u>Forecast</u>	<u>Nov-Oct</u>
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
THROUGHPUT (Dth)													
<u>Rate Class</u>													
(1) SALES													
(2) Residential Non-Heating	22,908	42,855	58,226	61,500	31,295	26,094	18,018	12,824	10,440	9,901	10,578	13,668	318,306
(3) Residential Non-Heating Low Income	1,636	2,537	3,337	3,630	2,286	2,110	1,451	1,021	824	724	774	1,028	21,358
(4) Residential Heating	1,109,606	2,448,726	3,490,353	3,717,114	2,876,908	2,073,184	1,087,131	594,919	412,329	362,322	380,623	490,598	19,043,813
(5) Residential Heating Low Income	106,303	209,952	282,811	295,762	273,613	217,290	116,926	67,274	46,870	39,870	42,639	54,212	1,753,519
(6) Small C&I	130,015	320,270	488,554	534,506	409,185	257,472	110,520	55,591	43,310	38,657	40,526	55,562	2,484,168
(7) Medium C&I	213,980	425,891	599,296	616,832	503,430	356,922	190,194	125,403	104,832	96,847	106,456	138,207	3,478,289
(8) Large LLF	35,053	78,012	109,270	123,692	113,339	77,973	38,475	19,140	11,241	8,222	6,595	17,416	638,427
(9) Large HLF	20,390	28,856	35,005	33,409	30,238	27,755	21,394	20,360	16,630	14,528	18,850	19,292	286,706
(10) Extra Large LLF	5,633	13,656	19,891	45,441	11,375	4,533	1,847	1,044	531	1,140	1,157	2,650	108,897
(11) Extra Large HLF	25,891	32,523	26,275	55,365	15,477	13,551	16,187	15,910	14,318	12,307	14,339	15,834	257,976
(12) Total SALES	1,671,413	3,603,279	5,113,016	5,487,251	4,267,145	3,056,882	1,602,141	913,486	661,324	584,517	622,537	808,467	28,391,460
(13) TSS													
(14) TSS Small C&I	147	661	1,207	1,971	0	0	0	0	0	0	0	0	3,987
(15) TSS Medium C&I	3,211	7,021	9,471	10,706	0	0	0	0	0	0	0	0	30,408
(16) TSS Large LLF	4,458	8,897	12,432	15,285	0	0	0	0	0	0	0	0	41,072
(17) TSS Large HLF	598	925	1,555	2,327	0	0	0	0	0	0	0	0	5,405
(18) TSS Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(19) TSS Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(20) Total TSS	8,414	17,504	24,664	30,289	0	0	0	0	0	0	0	0	80,871
(21) Sales & TSS THROUGHPUT													
(22) Residential Non-Heating	22,908	42,855	58,226	61,500	31,295	26,094	18,018	12,824	10,440	9,901	10,578	13,668	318,306
(23) Residential Non-Heating Low Income	1,636	2,537	3,337	3,630	2,286	2,110	1,451	1,021	824	724	774	1,028	21,358
(24) Residential Heating	1,109,606	2,448,726	3,490,353	3,717,114	2,876,908	2,073,184	1,087,131	594,919	412,329	362,322	380,623	490,598	19,043,813
(25) Residential Heating Low Income	106,303	209,952	282,811	295,762	273,613	217,290	116,926	67,274	46,870	39,870	42,639	54,212	1,753,519
(26) Small C&I	130,162	320,931	489,761	536,477	409,185	257,472	110,520	55,591	43,310	38,657	40,526	55,562	2,488,155
(27) Medium C&I	217,191	432,911	608,767	627,538	503,430	356,922	190,194	125,403	104,832	96,847	106,456	138,207	3,508,697
(28) Large LLF	39,511	86,909	121,701	138,977	113,339	77,973	38,475	19,140	11,241	8,222	6,595	17,416	679,499
(29) Large HLF	20,988	29,781	36,560	35,736	30,238	27,755	21,394	20,360	16,630	14,528	18,850	19,292	292,111
(30) Extra Large LLF	5,633	13,656	19,891	45,441	11,375	4,533	1,847	1,044	531	1,140	1,157	2,650	108,897
(31) Extra Large HLF	25,891	32,523	26,275	55,365	15,477	13,551	16,187	15,910	14,318	12,307	14,339	15,834	257,976
(32) Total SALES & TSS THROUGHPUT	1,679,827	3,620,782	5,137,680	5,517,540	4,267,145	3,056,882	1,602,141	913,486	661,324	584,517	622,537	808,467	28,472,331
(33) FT-1 TRANSPORTATION													
(34) FT-1 Small	0	0	0	0	0	0	0	0	0	0	0	0	0
(35) FT-1 Medium	39,744	20,608	75,699	82,188	68,743	46,081	28,893	21,639	18,554	18,679	21,701	30,546	473,074
(36) FT-1 Large LLF	47,563	45,005	113,694	124,633	98,495	66,413	35,134	19,657	13,421	12,342	15,857	33,288	625,502
(37) FT-1 Large HLF	22,879	6,082	38,468	45,228	37,030	30,922	28,515	25,339	22,247	24,653	27,697	31,468	340,527
(38) FT-1 Extra Large LLF	62,873	78,813	127,392	178,007	166,529	110,644	60,347	31,767	21,601	20,501	27,662	54,005	940,142
(39) FT-1 Extra Large HLF	388,400	23,484	502,496	542,101	496,244	464,875	429,662	410,267	407,130	409,649	427,317	439,647	4,941,272
(40) Default	3,086	14,071	8,688	32,683	0	0	0	0	0	0	0	0	58,529
(41) TOTAL FT-1 TRANSPORTATION	564,544	188,064	866,438	1,004,840	867,041	718,934	582,551	508,669	482,954	485,824	520,233	588,955	7,379,046
(42) FT-2 TRANSPORTATION													
(43) FT-2 Small	12,639	28,285	39,876	44,734	29,612	18,816	9,189	5,048	5,279	3,247	3,565	5,410	205,700
(44) FT-2 Medium	122,950	237,335	308,086	338,806	276,092	198,707	113,416	67,172	50,975	46,219	50,832	68,766	1,879,355
(45) FT-2 Large LLF	88,340	176,927	357,226	262,270	226,643	165,767	86,224	37,855	20,416	17,434	19,175	33,570	1,491,848
(46) FT-2 Large HLF	45,868	61,193	75,431	82,553	60,278	52,837	42,565	35,108	30,220	29,306	32,165	34,886	582,410
(47) FT-2 Extra Large LLF	8,020	18,445	22,098	25,004	16,587	11,682	6,629	3,467	1,646	1,811	3,249	3,920	122,559
(48) FT-2 Extra Large HLF	28,838	28,545	27,922	44,167	32,040	35,210	32,169	30,519	26,717	23,353	28,533	30,820	368,842
(49) TOTAL FT-2 TRANSPORTATION	306,655	550,730	830,649	797,535	641,252	483,018	290,191	179,169	135,253	121,370	137,518	177,373	4,650,713
(50) Total THROUGHPUT													
(51) Residential Non-Heating	22,908	42,855	58,226	61,500	31,295	26,094	18,018	12,824	10,440	9,901	10,578	13,668	318,306
(52) Residential Non-Heating Low Income	1,636	2,537	3,337	3,630	2,286	2,110	1,451	1,021	824	724	774	1,028	21,358
(53) Residential Heating	1,109,606	2,448,726	3,490,353	3,717,114	2,876,908	2,073,184	1,087,131	594,919	412,329	362,322	380,623	490,598	19,043,813
(54) Residential Heating Low Income	106,303	209,952	282,811	295,762	273,613	217,290	116,926	67,274	46,870	39,870	42,639	54,212	1,753,519
(55) Small C&I	142,801	349,216	529,637	581,211	438,797	276,287	119,708	60,639	48,589	41,905	44,091	60,972	2,693,855
(56) Medium C&I	379,885	690,854	992,552	1,048,532	848,264	601,710	332,503	214,213	174,360	161,745	178,989	237,520	5,861,126
(57) Large LLF	175,414	308,841	592,621	625,881	438,477	310,153	159,833	76,652	45,078	37,999	41,627	84,274	2,796,849
(58) Large HLF	89,735	97,055	150,460	163,518	127,546	111,514	92,474	80,807	69,097	68,486	78,712	85,646	1,215,048
(59) Extra Large LLF	76,526	110,914	169,381	248,452	194,491	126,859	68,823	36,279	23,778	23,452	32,068	60,575	1,171,598
(60) Extra Large HLF	443,128	84,553	556,702	641,632	543,760	513,636	478,018	456,696	448,166	445,308	470,189	486,302	5,568,090
(61) Default	3,086	14,071	8,688	32,683	0	0	0	0	0	0	0	0	58,529
(62) TOTAL THROUGHPUT	2,551,027	4,359,576	6,834,767	7,319,915	5,775,438	4,258,835	2,474,884	1,601,324	1,279,531	1,191,711	1,280,289	1,574,794	40,502,090

Attachment TGS-4
Bill Impact Analysis

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Heating:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) Difference due to:			(j)	(k)
	Annual	Proposed	Current				DAC					
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(1)												
(2)												
(3)												
(4)												
(5)	104	\$308.02	\$272.49	\$35.53	13.0%	\$34.46	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.07
(6)	115	\$330.92	\$291.64	\$39.28	13.5%	\$38.10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.18
(7)	126	\$353.81	\$310.78	\$43.03	13.8%	\$41.74	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.29
(8)	137	\$376.72	\$329.93	\$46.79	14.2%	\$45.39	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.40
(9)	149	\$401.74	\$350.86	\$50.88	14.5%	\$49.35	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.53
(10)	160	\$424.65	\$370.01	\$54.64	14.8%	\$53.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.64
(11)	171	\$447.57	\$389.17	\$58.40	15.0%	\$56.65	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.75
(12)	183	\$472.56	\$410.03	\$62.53	15.2%	\$60.65	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.88
(13)	194	\$495.43	\$429.16	\$66.27	15.4%	\$64.28	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.99
(14)	205	\$518.36	\$448.34	\$70.02	15.6%	\$67.92	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.10
(15)	216	\$541.24	\$467.46	\$73.78	15.8%	\$71.57	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.21

Residential Heating Low Income:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) Difference due to:			(j)	(k)	(l)
	Annual	Proposed	Current				Total Bill	DAC					
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET	
(16)													
(17)													
(18)													
(19)													
(20)	104	\$229.11	\$202.47	\$26.64	13.2%	\$34.46	(\$8.61)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.80
(21)	115	\$246.10	\$216.64	\$29.46	13.6%	\$38.10	(\$9.53)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.88
(22)	126	\$263.06	\$230.79	\$32.27	14.0%	\$41.74	(\$10.44)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.97
(23)	137	\$280.05	\$244.95	\$35.10	14.3%	\$45.39	(\$11.35)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.05
(24)	149	\$298.59	\$260.43	\$38.16	14.7%	\$49.35	(\$12.34)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.14
(25)	160	\$315.57	\$274.59	\$40.98	14.9%	\$53.00	(\$13.25)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.23
(26)	171	\$332.55	\$288.75	\$43.80	15.2%	\$56.65	(\$14.16)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.31
(27)	183	\$351.09	\$304.19	\$46.89	15.4%	\$60.65	(\$15.16)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.41
(28)	194	\$368.04	\$318.34	\$49.70	15.6%	\$64.28	(\$16.07)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.49
(29)	205	\$385.03	\$332.51	\$52.52	15.8%	\$67.92	(\$16.98)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.58
(30)	216	\$402.00	\$346.66	\$55.34	16.0%	\$71.57	(\$17.89)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.66

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Non-Heating:												
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) Difference due to:		(i)	(j)	(k)
	Annual	Proposed	Current				DAC					
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(31)												
(32)												
(33)												
(34)												
(35)	44	\$184.22	\$169.21	\$15.01	8.9%	\$14.56	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.45
(36)	47	\$190.55	\$174.53	\$16.02	9.2%	\$15.54	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.48
(37)	51	\$198.98	\$181.58	\$17.40	9.6%	\$16.88	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.52
(38)	57	\$211.63	\$192.16	\$19.46	10.1%	\$18.88	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.58
(39)	60	\$217.99	\$197.49	\$20.49	10.4%	\$19.88	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.61
(40)	66	\$230.66	\$208.12	\$22.54	10.8%	\$21.86	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.68
(41)	72	\$243.29	\$218.71	\$24.59	11.2%	\$23.85	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.74
(42)	75	\$249.62	\$224.02	\$25.60	11.4%	\$24.83	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.77
(43)	81	\$262.28	\$234.61	\$27.67	11.8%	\$26.84	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.83
(44)	85	\$270.70	\$241.67	\$29.03	12.0%	\$28.16	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.87
(45)	89	\$279.18	\$248.77	\$30.40	12.2%	\$29.49	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.91

Residential Non-Heating Low Income:													
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) Difference due to:		(i)	(j)	(k)	(l)
	Annual	Proposed	Current				Total Bill	DAC					
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET	
(46)													
(47)													
(48)													
(49)													
(50)	44	\$137.36	\$126.11	\$11.26	8.9%	\$14.56	(\$3.64)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.34
(51)	47	\$142.06	\$130.04	\$12.02	9.2%	\$15.54	(\$3.89)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.36
(52)	51	\$148.31	\$135.25	\$13.05	9.6%	\$16.88	(\$4.22)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.39
(53)	57	\$157.68	\$143.08	\$14.60	10.2%	\$18.88	(\$4.72)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.44
(54)	60	\$162.39	\$147.02	\$15.37	10.5%	\$19.88	(\$4.97)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.46
(55)	66	\$171.78	\$154.88	\$16.90	10.9%	\$21.86	(\$5.47)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.51
(56)	72	\$181.16	\$162.72	\$18.44	11.3%	\$23.85	(\$5.96)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.55
(57)	75	\$185.85	\$166.65	\$19.20	11.5%	\$24.83	(\$6.21)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.58
(58)	81	\$195.24	\$174.48	\$20.75	11.9%	\$26.84	(\$6.71)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.62
(59)	85	\$201.48	\$179.71	\$21.77	12.1%	\$28.16	(\$7.04)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.65
(60)	89	\$207.74	\$184.94	\$22.80	12.3%	\$29.49	(\$7.37)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.68

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I Small:												
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) Difference due to:		(i)	(j)	(k)
	Annual	Proposed	Current				DAC					
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(61)												
(62)												
(63)												
(64)												
(65)	140	\$414.44	\$366.61	\$47.82	13.0%	\$46.39	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.43
(66)	156	\$443.55	\$390.28	\$53.27	13.6%	\$51.67	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.60
(67)	171	\$470.88	\$412.48	\$58.40	14.2%	\$56.65	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.75
(68)	186	\$498.17	\$434.64	\$63.53	14.6%	\$61.62	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.91
(69)	200	\$523.69	\$455.38	\$68.31	15.0%	\$66.26	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.05
(70)	216	\$552.83	\$479.07	\$73.75	15.4%	\$71.54	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.21
(71)	232	\$581.96	\$502.73	\$79.23	15.8%	\$76.85	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.38
(72)	247	\$609.28	\$524.92	\$84.36	16.1%	\$81.83	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.53
(73)	261	\$634.78	\$545.63	\$89.14	16.3%	\$86.47	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.67
(74)	276	\$662.09	\$567.82	\$94.27	16.6%	\$91.44	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.83
(75)	292	\$691.23	\$591.49	\$99.74	16.9%	\$96.75	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.99

C & I Medium:												
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) Difference due to:		(i)	(j)	(k)
	Annual	Proposed	Current				DAC					
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(76)												
(77)												
(78)												
(79)												
(80)	1,699	\$3,497.82	\$2,917.52	\$580.30	19.9%	\$562.89	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$17.41
(81)	1,882	\$3,817.45	\$3,174.66	\$642.79	20.2%	\$623.51	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$19.28
(82)	2,063	\$4,133.67	\$3,429.04	\$704.63	20.5%	\$683.49	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$21.14
(83)	2,246	\$4,453.29	\$3,686.16	\$767.12	20.8%	\$744.11	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$23.01
(84)	2,430	\$4,774.49	\$3,944.53	\$829.96	21.0%	\$805.06	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$24.90
(85)	2,612	\$5,092.57	\$4,200.44	\$892.13	21.2%	\$865.37	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$26.76
(86)	2,794	\$5,410.68	\$4,456.39	\$954.29	21.4%	\$925.66	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$28.63
(87)	2,978	\$5,731.85	\$4,714.72	\$1,017.13	21.6%	\$986.62	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$30.51
(88)	3,161	\$6,051.46	\$4,971.84	\$1,079.62	21.7%	\$1,047.23	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$32.39
(89)	3,342	\$6,367.66	\$5,226.21	\$1,141.44	21.8%	\$1,107.20	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$34.24
(90)	3,525	\$6,687.32	\$5,483.38	\$1,203.95	22.0%	\$1,167.83	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$36.12

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I LLF Large:											
	(a)	(b)	(c)	(d)	(e)	(f)	(g) (h) Difference due to:		(i)	(j)	(k)
	Annual	Proposed	Current				DAC				
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(91)											
(92)											
(93)											
(94)											
(95)	6,417	\$13,242.34	\$11,050.64	\$2,191.70	19.8%	\$2,125.95	\$0.00	\$0.00	\$0.00	\$0.00	\$65.75
(96)	7,107	\$14,532.85	\$12,105.46	\$2,427.39	20.1%	\$2,354.57	\$0.00	\$0.00	\$0.00	\$0.00	\$72.82
(97)	7,800	\$15,828.28	\$13,164.23	\$2,664.05	20.2%	\$2,584.13	\$0.00	\$0.00	\$0.00	\$0.00	\$79.92
(98)	8,491	\$17,120.66	\$14,220.58	\$2,900.08	20.4%	\$2,813.08	\$0.00	\$0.00	\$0.00	\$0.00	\$87.00
(99)	9,182	\$18,412.63	\$15,276.58	\$3,136.05	20.5%	\$3,041.97	\$0.00	\$0.00	\$0.00	\$0.00	\$94.08
(100)	9,872	\$19,703.51	\$16,331.75	\$3,371.75	20.6%	\$3,270.60	\$0.00	\$0.00	\$0.00	\$0.00	\$101.15
(101)	10,562	\$20,994.30	\$17,386.88	\$3,607.41	20.7%	\$3,499.19	\$0.00	\$0.00	\$0.00	\$0.00	\$108.22
(102)	11,254	\$22,287.88	\$18,444.12	\$3,843.76	20.8%	\$3,728.45	\$0.00	\$0.00	\$0.00	\$0.00	\$115.31
(103)	11,944	\$23,578.73	\$19,499.30	\$4,079.43	20.9%	\$3,957.05	\$0.00	\$0.00	\$0.00	\$0.00	\$122.38
(104)	12,637	\$24,874.15	\$20,558.05	\$4,316.10	21.0%	\$4,186.62	\$0.00	\$0.00	\$0.00	\$0.00	\$129.48
(105)	13,327	\$26,164.63	\$21,612.85	\$4,551.78	21.1%	\$4,415.23	\$0.00	\$0.00	\$0.00	\$0.00	\$136.55

C & I HLF Large:											
	(a)	(b)	(c)	(d)	(e)	(f)	(g) (h) Difference due to:		(i)	(j)	(k)
	Annual	Proposed	Current				DAC				
	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(106)											
(107)											
(108)											
(109)											
(110)	18,017	\$27,080.83	\$20,927.20	\$6,153.63	29.4%	\$5,969.02	\$0.00	\$0.00	\$0.00	\$0.00	\$184.61
(111)	19,956	\$29,861.71	\$23,045.81	\$6,815.90	29.6%	\$6,611.42	\$0.00	\$0.00	\$0.00	\$0.00	\$204.48
(112)	21,897	\$32,645.22	\$25,166.39	\$7,478.82	29.7%	\$7,254.46	\$0.00	\$0.00	\$0.00	\$0.00	\$224.36
(113)	23,835	\$35,424.73	\$27,283.98	\$8,140.74	29.8%	\$7,896.52	\$0.00	\$0.00	\$0.00	\$0.00	\$244.22
(114)	25,777	\$38,209.62	\$29,405.59	\$8,804.03	29.9%	\$8,539.91	\$0.00	\$0.00	\$0.00	\$0.00	\$264.12
(115)	27,717	\$40,991.82	\$31,525.18	\$9,466.64	30.0%	\$9,182.64	\$0.00	\$0.00	\$0.00	\$0.00	\$284.00
(116)	29,657	\$43,773.99	\$33,644.76	\$10,129.23	30.1%	\$9,825.35	\$0.00	\$0.00	\$0.00	\$0.00	\$303.88
(117)	31,599	\$46,558.81	\$35,766.31	\$10,792.51	30.2%	\$10,468.73	\$0.00	\$0.00	\$0.00	\$0.00	\$323.78
(118)	33,537	\$49,338.35	\$37,883.92	\$11,454.43	30.2%	\$11,110.80	\$0.00	\$0.00	\$0.00	\$0.00	\$343.63
(119)	35,478	\$52,121.90	\$40,004.51	\$12,117.39	30.3%	\$11,753.87	\$0.00	\$0.00	\$0.00	\$0.00	\$363.52
(120)	37,418	\$54,904.55	\$42,124.57	\$12,779.98	30.3%	\$12,396.58	\$0.00	\$0.00	\$0.00	\$0.00	\$383.40

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

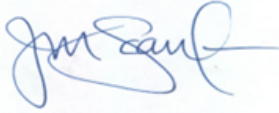
	C & I LLF Extra-Large:											
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) Difference due to:		(i)	(j)	(k)
	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC		EE	LIHEAP	GET	
							Base DAC	ISR				
(121)												
(122)												
(123)												
(124)												
(125)	44,054	\$65,981.37	\$50,934.88	\$15,046.48	29.5%	\$14,595.09	\$0.00	\$0.00	\$0.00	\$0.00	\$451.39	
(126)	48,799	\$72,754.27	\$56,087.15	\$16,667.12	29.7%	\$16,167.11	\$0.00	\$0.00	\$0.00	\$0.00	\$500.01	
(127)	53,540	\$79,522.57	\$61,236.16	\$18,286.41	29.9%	\$17,737.82	\$0.00	\$0.00	\$0.00	\$0.00	\$548.59	
(128)	58,285	\$86,295.47	\$66,388.44	\$19,907.03	30.0%	\$19,309.82	\$0.00	\$0.00	\$0.00	\$0.00	\$597.21	
(129)	63,029	\$93,067.20	\$71,539.88	\$21,527.32	30.1%	\$20,881.50	\$0.00	\$0.00	\$0.00	\$0.00	\$645.82	
(130)	67,774	\$99,840.11	\$76,692.14	\$23,147.97	30.2%	\$22,453.53	\$0.00	\$0.00	\$0.00	\$0.00	\$694.44	
(131)	72,519	\$106,613.01	\$81,844.41	\$24,768.60	30.3%	\$24,025.54	\$0.00	\$0.00	\$0.00	\$0.00	\$743.06	
(132)	77,263	\$113,384.74	\$86,995.83	\$26,388.91	30.3%	\$25,597.24	\$0.00	\$0.00	\$0.00	\$0.00	\$791.67	
(133)	82,008	\$120,157.64	\$92,148.09	\$28,009.55	30.4%	\$27,169.26	\$0.00	\$0.00	\$0.00	\$0.00	\$840.29	
(134)	86,749	\$126,925.91	\$97,297.10	\$29,628.81	30.5%	\$28,739.95	\$0.00	\$0.00	\$0.00	\$0.00	\$888.86	
(135)	91,494	\$133,698.83	\$102,449.40	\$31,249.43	30.5%	\$30,311.95	\$0.00	\$0.00	\$0.00	\$0.00	\$937.48	

	C & I HLF Extra-Large:											
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) Difference due to:		(i)	(j)	(k)
	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC		EE	LIHEAP	GET	
							Base DAC	ISR				
(136)												
(137)												
(138)												
(139)												
(140)	228,602	\$271,137.47	\$193,059.28	\$78,078.20	40.4%	\$75,735.85	\$0.00	\$0.00	\$0.00	\$0.00	\$2,342.35	
(141)	253,223	\$300,005.98	\$213,518.58	\$86,487.39	40.5%	\$83,892.77	\$0.00	\$0.00	\$0.00	\$0.00	\$2,594.62	
(142)	277,841	\$328,870.84	\$233,975.24	\$94,895.60	40.6%	\$92,048.73	\$0.00	\$0.00	\$0.00	\$0.00	\$2,846.87	
(143)	302,462	\$357,739.39	\$254,434.57	\$103,304.81	40.6%	\$100,205.67	\$0.00	\$0.00	\$0.00	\$0.00	\$3,099.14	
(144)	327,078	\$386,602.04	\$274,889.74	\$111,712.30	40.6%	\$108,360.93	\$0.00	\$0.00	\$0.00	\$0.00	\$3,351.37	
(145)	351,698	\$415,469.45	\$295,348.27	\$120,121.18	40.7%	\$116,517.54	\$0.00	\$0.00	\$0.00	\$0.00	\$3,603.64	
(146)	376,318	\$444,336.89	\$315,806.85	\$128,530.04	40.7%	\$124,674.14	\$0.00	\$0.00	\$0.00	\$0.00	\$3,855.90	
(147)	400,934	\$473,199.58	\$336,262.02	\$136,937.56	40.7%	\$132,829.43	\$0.00	\$0.00	\$0.00	\$0.00	\$4,108.13	
(148)	425,555	\$502,068.07	\$356,721.31	\$145,346.76	40.7%	\$140,986.36	\$0.00	\$0.00	\$0.00	\$0.00	\$4,360.40	
(149)	450,173	\$530,932.93	\$377,177.97	\$153,754.96	40.8%	\$149,142.31	\$0.00	\$0.00	\$0.00	\$0.00	\$4,612.65	
(150)	474,794	\$559,801.48	\$397,637.32	\$162,164.16	40.8%	\$157,299.24	\$0.00	\$0.00	\$0.00	\$0.00	\$4,864.92	

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate were electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.



Joanne M. Scanlon

March 31, 2026
Date

**Docket No. 25-22-NG – Narragansett Electric Co. d/b/a Rhode Island Energy
2025 Gas Cost Recovery Filing (GCR) and 2025 Distribution Adjustment Clause (DAC)
Service List as of 8/21/2025**

Name/Address	E-mail	Phone
The Narragansett Electric Company d/b/d Rhode Island Energy Celia B. O’Brien, Esq. 280 Melrose Street Providence, RI 02907	COBrien@pplweb.com ;	401-578-2700
	JHutchinson@pplweb.com ;	
	JScanlon@pplweb.com ;	
Steven Boyajian, Esq. Robinson & Cole LLP One Financial Plaza, 14 th Floor Providence, RI 02903	SBoyajian@rc.com ;	401-709-3359
	LPimentel@rc.com ;	
	HSeddon@rc.com ;	
Rhode Island Energy Stephanie A. Briggs Jeffrey D. Oliveira Tyler G. Shields Peter R. Blazunas James M. Stephens Terry Crupi Scott Porter Tim Jones Jared Long Michele V. Leone Laeyeng H. Hunt Brandon W. Flynn Kim Dao Ariel McCord Phil LaFond	SBriggs@pplweb.com ;	
	JOliveira@pplweb.com ;	
	TGShields@pplweb.com ;	
	PBlazunas@ceadvisors.com ;	
	JMStephens@pplweb.com ;	
	TJCrupi@pplweb.com ;	
	SWPorter@pplweb.com ;	
	Tim.Jones@lge-ku.com ;	
	Jared.Long@lge-ku.com ;	
	MVLeone@RIEnergy.com ;	
	LHHunt@RIEnergy.com ;	
	BFlynn@RIEnergy.com ;	
KDao@RIEnergy.com ;		
EMcCord@RIEnergy.com ;		

	PLaFond@RIEnergy.com ;	
	KMCampbell@RIEnergy.com ;	
Division of Public Utilities (DIV) Leo Wold, Esq. Division of Public Utilities	Leo.wold@dpuc.ri.gov ;	401-780-2177
	John.bell@dpuc.ri.gov ;	
	joel.munoz@dpuc.ri.gov ;	
	Al.mancini@dpuc.ri.gov ;	
	Margaret.L.Hogan@dpuc.ri.gov ;	
	Mark.A.Simpkins@dpuc.ri.gov ;	
	Kyle.J.Lynch@dpuc.ri.gov ;	
	gregory.schultz@dpuc.ri.gov ;	
	john.r.harrington@dpuc.ri.gov ;	
	nicole.m.corbin@dpuc.ri.gov ;	
	Ellen.Golde@dpuc.ri.gov ;	
	Machaela.Seaton@dpuc.ri.gov ;	
Jerome Mierzwa Exeter Associates, Inc. 10480 Little Patuxent Parkway, Suite 300 Columbia, MD 21044	jmierzwa@exeterassociates.com ;	410-992-7500
David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com ;	603-964-6526
File an original & 9 copies w/ PUC: Stephanie De La Rosa, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	stephanie.delarosa@puc.ri.gov ;	401-780-2107
	Patricia.lucarelli@puc.ri.gov ;	
	Alan.nault@puc.ri.gov ;	
	Christopher.Caramello@puc.ri.gov ;	
Christopher Kearns Office of Energy Resources	Christopher.Kearns@energy.ri.gov ;	
	William.Owen@energy.ri.gov ;	
Nicholas Vaz, Esq. RI Attorney General Office	nvaz@riag.ri.gov ;	
	mbedell@riag.ri.gov ;	
James Crowley, Esq. Conservation Law Foundation	jcrowley@clf.org ;	