STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT	**:**	
ELECTRIC COMPANY	**:**	**DOCKET NO. 4719**
d/b/a NATIONAL GRID	**:**	
2017 GAS COST RECOVERY CHARGE	**:**	

REPORT AND ORDER

I. Introduction

On September 1, 2017, The Narragansett Electric Company d/b/a National Grid (National Grid or Company) submitted its Gas Cost Recovery (GCR) filing to the Public Utilities Commission (PUC or Commission).[1] The GCR is an annual filing that allows National Grid to reconcile and recover its estimated costs for gas supplies, including pipeline transportation and storage charges, for the GCR year beginning November 1. The original filing proposed a total bill annual increase of approximately $38.46 for a typical residential heating customer using the equivalent of 846 therms per year, or 3.2 %. On September 20, 2017, the Company filed a market hedge proposal for its Gas Procurement Incentive Plan in PUC Docket No. 4647.[2] As a direct consequence of the market hedge proposal, on September 29, 2017, the Company filed a supplement to the September 1, GCR filing. The supplement proposed a total bill increase of approximately $44.85, or 3.8%, from the currently existing rates.[3] On October 3, 2017, pursuant to the Company's effective gas tariff, RIPUC NG-GAS No. 101, Section 1, Schedule B, Sheet 1 (definition

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[1] All filings in this docket are available at the Commission offices located at 89 Jefferson Boulevard, Warwick, Rhode Island or at http://www.ripuc.org/eventsactions/docket/4719page.html.
[2] http://www.ripuc.org/eventsactions/docket/4647-NGrid-GPIP-HedgeProposal(9-20-17).pdf.
[3] Letter of Robert Humm (Sept. 29, 2017); http://www.ripuc.org/eventsactions/docket/4719-NGrid-SupplementalGCR(9-29-17).pdf.

of British thermal unit (BTU) content factor), the Company filed its semi-annual BTU factor report which proposed a BTU content factor of 1.029 for the period of November 1, 2017 through April 30, 2018.[4]

On October 16, 2017, the Division of Public Utilities and Carriers (Division) filed a memorandum from its consultant, Bruce R. Oliver, concurring generally with the plan, with a few exceptions. Mr. Oliver recommended that the PUC shift $764,118 from the GCR to the Distribution Adjustment Charge (DAC). Mr. Oliver also recommended that the PUC exclude from proposed 2017-18 GCR factors the costs associated with leasing third-party portable LNG equipment and services in Cumberland.[5] In a filing dated October 23, 2017, the Company agreed with both recommendations and also corrected an error in the FT-2 demand rate and storage costs, as identified in Attachment AEL-5S. The revised bill impact to an average residential customer using 846 therms per year was an increase of $43.25 or 3.7% over existing rates.[6] On October 30, 2017, the PUC conducted an Open Meeting and unanimously approved the 2017 Gas Cost Recovery factors and the BTU factor for the period of November 2017 through April 2018.

II. National Grid's September 1, 2017 Filing

In support of its filing, National Grid submitted the prefiled testimonies of Nancy G. Culliford, Manager of Gas Supply Planning; Ann E. Leary, Manager of New England Gas Pricing for National Grid USA Service Company, Inc.; Theodore E. Poe, Jr., Manager of Gas Load Forecasting and Analysis; and John M. Protano, Manager of Origination and

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[4] Letter of Robert Humm; http://www.ripuc.org/eventsactions/docket/4719-NGrid-BTU-SemiAnnual(10-3-17).pdf.
[5] *See* http://www.ripuc.org/eventsactions/docket/4719-DPU-Oliver-Redacted_10_16_17.pdf.
[6] *See* Company Reply at 1-2; http://www.ripuc.org/eventsactions/docket/4719-NGrid%20Reply(Redacted)(10-23-17).pdf.

Price Volatility Management in the Energy Procurement organization of National Grid USA Service Company, Inc.[7]

Ms. Culliford's testimony provided support for the estimated gas costs, assignment of pipeline capacity to marketers, other issues relating to the Company's proposed 2017-2018 factors, and modifications made to National Grid's portfolio for the 2017 GCR period.[8] She explained that the proposed GCR factors are based on the New York Mercantile Exchange (NYMEX) strip as of the close of trading on July 31, 2017 and the difference between the futures contract purchases under the Gas Procurement Incentive Plan (GPIP) as of July 31, 2017 and the July 31, 2017 NYMEX strip. The factors also reflect storage and inventory costs as of July 31, 2017 and the projected cost of purchasing gas ratably through the injection season as provided for in the Natural Gas Portfolio Management Plan (NGPMP). She reported that the current year's average NYMEX pricing was lower than it was the previous year.[9]

Ms. Culliford explained how the Company uses a SENDOUT model to calculate projected gas costs. To minimize yearly supply costs, the model uses pricing, contract, and storage information to determine the dispatch of supplies.[10] Ms. Culliford explained the two gas cost components for the GCR: (1) Supply Fixed Costs, which include purchase, storage, or delivery of firm gas as well as pipeline and supplier fixed reservation costs, demand charges, and transportation fees; and (2) Supply Variable Costs, which include commodity costs, taxes on commodity, other gas supply expenses incurred to transport and

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[7] http://www.ripuc.org/eventsactions/docket/4719-NGrid-GCR-Book1(9-1-17).pdf and http://www.ripuc.org/eventsactions/docket/4719-NGrid-GCR-Book2(9-1-17).pdf.
[8] Culliford Direct at Bates 4 (Sept. 1, 2017).
[9] *Id.* at Bates 7; Attach. NGC-3.
[10] *Id.*

store the gas, and inventory commodity costs.[11] Attached to her testimony, Ms. Culliford provided supporting detail for the gas costs.[12] She described how the Company calculates the delivered cost for a particular gas supply. Beginning with the NYMEX price, the amount is then adjusted for basis differential and to reflect fuel retention, and finally, the cost of transportation on the pipeline is added.[13]

Ms. Culliford explained that National Grid would continue to operate its portfolio the way it had the prior year. She described the Company's portfolio as well-positioned to take advantage of opportunities presented by the development of the Marcellus basin, utilizing its economically priced market area transportation on existing long and short-haul capacity. She explained that the Company purchases less expensive supplies on the Texas Eastern Transmission (Texas Eastern) Market Area 2 (M2) and Market Area 3 (M3) points delivered to the Company's city-gates on the Algonquin Gas Transmission (Algonquin) pipeline, as well as the Tennessee Gas Pipeline Company, LLC (Tennessee) Zone 4 (Zone 4) point using existing pipeline contracts previously used to purchase Gulf of Mexico supplies.[14]

Ms. Culliford reported that the Company had issued a Request for Proposals (RFP) for an Asset Management and Gas Supply Agreement (AMA) with an effective date of November 1, 2017, to provide a maximum daily quantity of 1,025 decatherms (Dth) per day with a swing component for the months of November 2017 and March 2018, and a baseload volume for the months of December 2017, January 2018, and February 2018.[15]

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[11] *Id.* at Bates 8.
[12] Culliford Direct. at Bates 8; Attach. NGC-1.
[13] Culliford Direct. at Bates 9.
[14] *Id*. at Bates 10.
[15] *Id.* at Bates 11.

Ms. Culliford described four changes to the Company's portfolio. First, the Company's Algonquin Incremental Market (AIM) contract for 18,000 Dth per day went fully into service effective January 7, 2017. Second, Texas Eastern Contract No. 800173 is no longer necessary and will expire, as of October 31, 2017, providing annual demand charge savings of $88,708.80. Third, the Company provided notice that National Fuel Contract No. E11395 is also no longer necessary and will terminate effective March 31, 2018, providing an annual demand charge savings of $53,765.88. Finally, the Company's Crary Street (f/k/a Manchester Street) lateral service (Contract No. 510985) with Algonquin was placed into service effective July 17, 2017. This new meter station is sized to move up to 96,000 Dth per day, eliminating the need to rely on LNG during the shoulder months for system pressures.[16] Ms. Culliford explained that the Company planned to have its LNG facilities filled by December 1, 2017.[17] Ms. Culliford provided an update to pending precedent agreements, two of which have been delayed due to permitting opposition,[18]and a third to be located in central Massachusetts, with an intended in-service date of April 1, 2019.[19]

Regarding marketer capacity assignments, Ms. Culliford represented that the Company had made available 35,258 Dth per day of capacity to marketers on seven different pipeline paths, with no changes from these capacity paths from last year. She explained the calculation of the surcharge/credit for each assigned pipeline path and the calculations of the delivered costs for each path released to marketers. She added a Fixed Unit Cost of $0.7302 per Dth to the system average pipeline unit variable cost of $0.1080

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[16] *Id*. at 14-15.
[17] *Id*. at 15.
[18] These agreements are: (1) the Millennium Eastern System Upgrade Project, originally intended to be in service for the 2017-2018 winter, but will be delayed until 2018-19; and (2) National Grid LNG precedent agreement for liquefaction services
[19] The Northeast Energy project will provide up to 1,780 Dth per day and 380,920 Dth per refill for a term of fifteen years of liquefaction services with Northeast Energy.

per Dth to derive the $0.6222 per Dth weighted average pipeline cost. She then added the weighted average pipeline cost to the 100% load factor per unit cost of $0.0029 for the marketer reconciliation adjustment to average pipeline cost of $0.6193 per Dth. She also explained the calculation for the delivered cost for each path.[20]

Ann E. Leary, Manager of New England Gas Pricing, provided testimony to propose GCR factors for firm sales service and transportation service.[21] She explained that the proposed GCR factors are load specific, High Load and Low Load, and necessary for the Company to be able to recover the projected gas costs allocated to its firm sales customers for the November 1, 2017 through October 31, 2018 period. For the twelve-month period ending October 31, 2018, Ms. Leary stated projected gas costs for the Company's firm sales customers were approximately $119.5 million. She identified other costs and credits that, when added to the costs for the firm sales customers, would total $131.6 million in net costs necessary for the Company to collect.[22]

Ms. Leary related that the Fixed Cost component includes all Fixed Costs related to the purchase, storage, and delivery of firm gas for both High and Low Load factor customers. She explained the derivation of the component that resulted in total Fixed Costs of $40.2 million to be allocated to and collected from ratepayers based on their proportion of design-winter use requirements. She explained that the GCR factors were determined by dividing the allocated fixed gas cost by the projected throughput for each group, the High Load group and the Low Load group. She proposed a GCR Fixed Low Load factor of $1.5618 per Dth and a GCR Fixed High Load factor of $1.1416 per Dth.[23]

[20] Culliford Direct at 18, Attach. NGC-4 at.11.
[21] Leary Direct at Bates 72 (Sept. 1, 2017).
[22] *Id.* at 73.
[23] *Id.* at 74.

Ms. Leary noted that the Company agreed previously to provide an annual reconciliation of Marketer Fixed Costs and described the calculation of the Marketer Fixed Cost Reconciliation Balance, which she stated updated the 2016/2017 pipeline surcharge/credit for each path using actual pipeline capacity costs, resulting in a Marketer credit of $21,603.[24] After finalizing the 2015/2016 Marketer reconciliation filed the prior year to replace forecasted capacity and revenues with actual capacity and revenues, Ms. Leary reconciled the actual revenues billed during November 2016 through October 2017 of $39,004 with the actual surcharge for the 2015/2016 period of $39,001 and the prior period 2014-2015 Marketer reconciliation credit balance of $14,451. This resulted in a net Marketer reconciliation credit of $14,494 for the 2015-2016 period.[25] The overall total Marketer reconciliation for the two-year period totals a credit of $36,098; credit of $21,603 for the 2016-2017 period and a credit of $14,494 for the 2015-2016 period.[26] She reported that, as requested by the Division's consultant, the Company provided additional detail in this filing concerning monthly capacity release information for each gas pipeline.[27] She stated that the monthly design sales forecast was calculated by applying a monthly heat factor to the monthly design degree day.[28]

In describing the Variable Cost component, Ms. Leary identified total Variable Costs as covering all Variable Costs of gas, including commodity costs; supply-related LNG operation and maintenance; working capital; inventory finance costs; pipeline refunds; and deferred cost balances. She calculated Variable Costs for the November 2017

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[24] *Id*. at 75; Attach. AEL-7, p. 1.
[25] Leary Direct at 76.
[26] *Id.*
[27] *Id.*
[28] *Id*. at 77.

through October 2018 period to be $91,420,724. She divided that number by the projected period throughput to reach a Variable Cost factor of $3.5277 per Dth.[29] She explained that the estimated deferred balance under-recovery of $13,547,454 at October 31, 2017 was incorporated into the GCR rate as well as the projected deferred gas cost balances for the November 2017 through October 2018 period.[30]

She presented a proposed FT-2 marketer demand rate of $7.6636 per Maximum Daily Quantity (MDQ) in Dth/month and the Storage and Peaking charge of $0.06517 per therm for FT-1 firm transportation customers returning to Transitional Sales Service (TSS). She also submitted capacity assignment percentages for the High Load and Low Load factors to be used in the determination of pipeline, underground storage, and peaking capacity for Marketers.[31]

Ms. Leary explained that the Company had experienced a small amount of negative sales from April 2016 through March 2017, as well as negative sales for TSS Large Low Load Factors and TSS Large High Load Factor customers during September 2016 and January 2017. Firm Transportation Service customer classes FT-1 Large Low Load Factor and FT-1 Extra Large Low Load Factor also experienced negative sales. Total negative sales were 41,790 Dth, equating to $0.11% of total annual sales. Finally, she provided that an average residential heating customer using 846 therms per year would experience an increase of $38.46 or 3.2%.[32]

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[29] *Id*. at 77; Attach. AEL-1 at 3, line11.
[30] Leary Direct at Bates 78, Attach. AEL-1 at 6.
[31] Leary Direct at Bates 78, Attach. AEL-6.
[32] Leary Direct at Bates 82. The $38.46 increase is comprised of an increase of $41.44 as a result of the proposed GCR factors, a decrease of $4.13 as a result of the proposed DAC factors (Docket 4708) and an increase of $1.15 in gross earnings tax.

Mr. Poe provided testimony to support the underlying retail and wholesale forecasts of natural gas customer requirements that is used to estimate the Company's gas costs. He explained that every April 1, the Company utilizes a five-step process to determine its ten-year forecast of customer requirements. He indicated that modeling of both customer count and use-per-customer is used to determine the Company's retail forecast, which is then modeled at the rate class level and further sub-categorized. He stated that the forecasted volume consists of the meter count and use-per-customer at the rate class level. The retail forecast also takes into account the impact of the Company's energy efficiency programs.[33] After determining the retail forecast, Mr. Poe explained that it is adjusted for billing lag and unaccounted-for-gas to determine the wholesale forecast. Both the retail and wholesale forecasts are used by the Company for supply, engineering, and financial planning.[34]

Mr. Poe advised that, as directed in the 2016 GCR, Docket No. 4647, the Company met with Division staff and discussed the Company's forecasting, planning methodology, and capacity contracts and, on January 27, 2017, submitted a report summarizing the discussions. The parties agreed that the Company's continued use of heating degree days measures for its forecasting and weather normalization analyses appears reasonable, with no compelling reason to switch to effective degree day measures, as is done in Massachusetts. The Company further agreed to include more detail in the annual GCR filing to: (1) document its treatment of zero-capacity (FT-1) customers; (2) document its meter count data; (3) provide information on the year-to-year changes in usage by month and rate class.[35] The Company further agreed to provide the Division with an informal

[33] Poe Direct at Bates 132 (Sept. 1, 2017).
[34] *Id.* at Bates 133.
[35] *Id.* at Bates 134.

update of its forecast once the forecast is finalized in June of each year and vetted by the Company.[36]

Mr. Poe explained that the Company's forecast begins with a retail level forecast of each of its internal rate codes. The Company forecasts the meter count and use per customer for each rate code which is then used to calculate the volume forecast. The Company also calculates an "unaccounted for" gas percentage.[37] Mr. Poe further explained that 73% percent of the Company's gas sales occur from November through March. The company's gas resource portfolio and gas supply purchases are designed to address its customers' needs during the winter peak period and throughout the year. He related that the current year's retail forecast of 39,429,900 MMBtu indicated a 0.1% decrease over the last year's total retail forecast, with total sales decreasing by 0.6% and Commercial/Industrial Transportation increasing by 0.9%.[38] Wholesale sales volume growth is forecasted at 26,638,727 MMBtu for the period November 2017 through October 2018, a decrease of 0.1 % over last year.[39] Mr. Poe explained that the Company develops appropriate design-day and design-year planning standards to design a least-cost, reliable supply portfolio for its forecast period. The purpose of a design-day standard is to establish the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system. The Company designs its standards using a three-step process: (1) the Company performs statistical analyses of the coldest days and of the annual degree days recorded over a historical period; (2) the Company conducts cost-benefit analyses to

[36] *Id*.
[37] *Id*. at Bates 135.
[38] *Id*. at Bates 137.
[39] *Id*. at Bates 139.

evaluate the cost of maintaining the resources necessary to meet design-level demand versus the cost to customers of experiencing service curtailments; and (3) the Company identifies design standards that would maintain reliability at the lowest cost.[40]

Mr. Protano discussed the results of the Gas Procurement Incentive Plan (GPIP)[41] for the period July 1, 2016 through March 31, 2017 and the results of the Natural Gas Portfolio Management Plan (NGPMP) for April 1, 2016 through March 31, 2017. The GPIP is designed to encourage the Company to purchase supply in a way designed to stabilize prices and reduce the risk of dramatically escalating commodity costs. This year's GPIP report is the first year of a revised GPIP incentive year, now ending in March.[42] Beginning next year, the GPIP incentive will be for the period April 1 through March 31.[43]

To determine the incentive or penalty under the GPIP for each month, the total savings are multiplied by a percentage, depending upon the timing of the execution date of the purchase gas transaction and the specific unit costs savings. For instance, for transactions with unit cost savings of less than $.50 which are executed more than four months prior to gas flow, the incentive payment to the Company is 10% of the total costs savings. For transactions with unit cost savings greater than $.50 which are executed more than eight months prior to gas flow, the incentive payment to the Company is 20% of the total costs savings. For transactions executed between one and four months, the incentive payment to the Company is 5%, regardless of total costs savings.

[40] *Id*. at Bates 142.
[41] The Gas Procurement Incentive Plan (GPIP) encourages the Company to purchase supply in a way that will stabilize supply and reduce the risk of extreme price escalation. It requires National Grid to lock in future gas prices over a twenty-four month horizon and to make these purchases in a structured series of monthly increments. The difference between the average unit cost of the mandatory hedges and the average unit cost of discretionary purchases is multiplied by the discretionary volumes to calculate total savings or cost.
[42] Previously, the GPIP incentive year ran from July to June.
[43] Protano Direct at Bates 6 (Sept. 1, 2017).

The Company calculated a total incentive of $54,616, which Mr. Protano proposed be granted in full.[44]

Mr. Protano described the NGPMP, which shifted management of the Company's gas portfolio from an external company to internally within National Grid. He noted that the program produced a total of $12,088,685.08 in savings from April 2016 through March 2017, $10,863,363.97 of which customers would receive. Mr. Protano noted that the Company does not include any revenue from Asset Management Agreements (AMA) in the incentive and was not proposing any changes to the NGPMP incentive at the current time. AMA fees are recorded as a credit on the pipeline demand charges and customers receive 100% of this benefit.[45] The Company requested approval of a NGPMP incentive of $1,225,321.10 for the April 2016 through March 2017 period.

III. National Grid's Request for an Additional Hedge

On September 20, 2017, National Grid filed a request in PUC Docket No. 4647 for an additional hedge to the GPIP for the upcoming winter season.[46] On September 29, 2017, the Company submitted a supplemental filing in this docket to update the GCR factors as a result of the market hedge proposal, together with a proposal to replace gas supply that is no longer available as a result of the decommissioning of the liquefied natural gas (LNG) tank in Cumberland. In support of the filing, the Company submitted supplemental testimony and attachments from Ann Leary, supplemental attachments from Nancy G. Culliford, and prefiled testimony from Stephen P. Greco. [47]

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[44] *Id.* at Bates 7.
[45] *Id*. at Bates 9.
[46] http://www.ripuc.org/eventsactions/docket/4647-NGrid-GPIP-HedgeProposal(9-20-17).pdf
[47] http://www.ripuc.org/eventsactions/docket/4719-NGrid-SupplementalGCR(9-29-17).pdf

As a result of the additional hedge proposal, Ms. Leary reported an increase in annual forecasted gas supply costs of $1.27 million from the forecast filed on September 1, 2017. The impact of the Company's proposal regarding Cumberland LNG, as presented by Mr. Greco, is an increase in forecasted gas supply cost of $637,000. Therefore, the Company's supplemental GCR filing presents an increase of $1.9 million from the forecasted gas supply costs filed on September 1, 2017. Overall, the proposed GCR factors in Attachment AEL-1S are intended to recover approximately $133.4 million in net costs over the period November 2017 through October 2018.[48] The hedge filing also impacted the FT-2 Marketer Demand rate, as well as the Storage and Peaking charge for FT-1 firm transportation customers eligible for TSS service, with both being increased slightly.[49]

Ms. Leary explained that the amount of supply-related local production and storage costs recovered through the GCR are determined in a general rate case. Those amounts are fixed until a new level is determined in a subsequent general rate case. That new amount then becomes allowed for recovery in the GCR, pursuant to the Company's tariff. In the instant proceeding, the Company is requesting a waiver from the tariff to allow for an upward adjustment to the current production and storage costs recovered through the GCR of $637,000 until a permanent solution to the LNG issue is determined.[50]

Ms. Leary also provided updated bill impacts. An average residential heating customer using 846 therms per year will experience a total annual bill of $1,229.20 based on the proposed GCR and DAC factors, which is an increase of $44.85, or 3.8%, from last

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[48] Ann E. Leary Supp. Test. at 3 (Sept. 29, 2017)
[49] *Id*.
[50] *Id*. at 5.

year's bills.[51] The annual bill impact has increased from the initial September 1, 2017 GCR filing by $6.39, or 0.5%.[52]

Mr. Greco serves as Director of Pressure Regulation and Liquefied Natural Gas and Compressed Natural Gas (CNG) Assets for National Grid U.S.A. He explained that, historically, the Cumberland LNG facility supplied up to 30,000 Dth per day and 80,000 Dth per season. It did so using, two permanent LNG vaporizers, each with a capacity of 750,000 thousand cubic feet per hour (mcfh), to achieve the design output of 30,000 Dth per day.[53]

For the 2017-18 winter season, the Company proposed to rent four portable high-pressure trailers, each with a capacity of 13,520 gallons, for temporary use at the Cumberland site. The capacity of the four trailers will approach 70% of the peak day forecast, reducing the frequency of refilling and, consequently, the amount of LNG transported to and from the site.[54] Mr. Greco explained that the Company had explored two other options for supply, but rejected them because of operational challenges and unacceptable risks. Therefore, the Company determined that leasing portable LNG from a third party was the most prudent and reliable option for its customers.[55] Mr. Greco indicated that for future winters, the Company is focused on achieving a long-term solution, but that for the upcoming season, the anticipated effective date for the portable LNG would be December 1, 2017.[56]

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[51] This increase of $44.85 is comprised of an increase of $47.63 as a result of the proposed GCR factors; a decrease of $4.13 as a result of the proposed DAC factors, for which the Company submitted a supplemental filing on September 1, 2017 in Docket No. 4708; and an increase of $1.35 in Gross Earnings Tax.

[52] *Id*.

[53] Greco Test. at 5 (Sept. 29, 2018).

[54] *Id*.

[55] *Id*. at 8.

[56] *Id*. at 10.

IV. Division's October 16, 2017 Filing

The Division submitted the testimony of its consultant, Bruce R. Oliver, who analyzed the Company's filing and made recommendations. Mr. Oliver noted that the 2017 GCR filing reflected an increase of approximately 11.7% in GCR charges from last year's approved levels. He also indicated that the increase was not due to gas cost increases, but rather from three factors: (1) a $6.4 million reduction in Fixed Cost over-recoveries; (2) a $5.5 million increase in Variable Cost under-recoveries; and (3) a $2.8 million reduction in the NGPMP Customer Benefit.[57] He summarized the adjustments for each customer class as follows: for Residential Hearing customers, Small C&I customers, Medium C&I customers, and low load factors Large and Extra Large C&I accounts, the increase will be 11.8% over the GCR levels from the 2016 filing.[58] The proposed increase for Residential Non-Heating customers and High Load Factor Large and Extra Large C&I accounts would be 8%. Transportation customers would experience decreases in the FT-2 Marketer Demand Rate and the Storage and Peaking Charge of 9.6% and 3.8% respectively.[59] The Weighted Average Upstream Pipeline Transportation Charge will increase by 61.9%.[60]

Mr. Oliver identified three areas of concern with this year's GCR filing: (1) The allocation of system pressure related costs to the DAC; (2) the treatment of the incremental Cumberland costs; and (3) adjustments to the forecasted monthly sales volumes in the Company's monthly deferred balance reports.[61] The purpose of the System Pressure factor in the DAC is to transfer costs related to the maintenance of the gas system pressure from

[57] Memo of Bruce R. Oliver at 2 (Oct. 16, 2017).
[58] *Id*.
[59] *Id*.
[60] *Id*.
[61] *Id*. at 3.

the GCR costs to the DAC, to ensure that all customers who utilize the system for gas deliveries, and thus benefit from the Company's efforts to maintain system pressures, share responsibility for those costs. If the costs were not transferred to the DAC, all costs associated with the Company's maintenance of system pressures would otherwise be borne exclusively by the Company's gas sales customers. Transportation customers would be effectively relieved of any responsibility for system pressure costs even though gas delivery to them is dependent upon the Company's ability to maintain system pressure.[62]

In 2012, the PUC approved a Settlement Agreement in Docket No. 4339 that set forth a methodology for determining how much funding of system pressure costs would be transferred from the GCR docket to the DAC docket. This methodology, which has been in use since November 2012, was based upon an allocation of 75.77% of the annual lease payments for the Providence LNG tank.[63] However, now that the Company has completed the Crary Street Gate Station which provides a high pressure feed off the Algonquin gas mainline, the Company no longer requires the use of LNG to maintain pressure in that area. Therefore, the Company submits that the time is ripe to modify the methodology, set forth in the Docket No. 4339 Settlement.

Even though the Division acknowledged that the Company's request to change the methodology was expected, the Division expressed two concerns to this proposal: (1) previously the Company had indicated that only a portion of the Providence LNG tank's capacity was used for system pressure and now the Company was claiming that 100% of the tank's capacity accounts for system pressure maintenance; and (2) the Docket No. 4339 methodology resulted from a compromise that included consideration of all LNG use for

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[62] *Id.* at 4.
[63] *Id.*

pressure support on the Company's Rhode Island system, not just pressure support from the Providence Tank.[64] The Division expressed reservations over the modified system pressure factor used by the Company in this Docket and recommended that that 100% of the demand charges associated with deliveries to the Crary Street station be assigned to system pressure support. Furthermore, the Division posited that costs for LNG or other sources of gas supply used to provide system pressure support should be included in the development of the Company's System Pressure Factor [65] Additionally, the Division recommended that prior to the Company's next DAC filing, the Company should clarify the costs associated with maintaining system pressure for other parts of the Rhode Island system and the extent to which those costs warrant incorporation in System Pressure Factor determinations for subsequent proceedings.[66]

The Company requested waiver of the tariff provisions regarding the definition of supply-related local production and storage costs to facilitate recovery of additional estimated costs of $637,000 to meet peak day requirements during the winter of 2017-2018. However, the Division averred that because the request was filed so late, it had inadequate time to fully investigate the matter. The Division recommended that the PUC either direct the Company to address this matter in its next rate case or approve only interim GCR rates and allow an additional extension of time within this Docket for the Division to investigate further.[67] Mr. Oliver also recommended approval of the Company's plan for cost recovery related to its Market Area Hedge plan for the winter of 2017-2018. He characterized it as

[64] *Id*. at 5.
[65] *Id*.
[66] *Id*. at 6.
[67] *Id*. at 6-7.

a reasonable strategy for reducing exposure to large cost increases in the face of extreme cold weather and adverse market conditions.

Mr. Oliver expressed concerns with noticeable adjustments to forecasted sales volumes within the Company's monthly GCR Deferred Balance Reports. He noted that such adjustments have not historically been the Company's practice. He argued that such unilateral changes were inappropriate and distorted the interpretation of the computed end-of-October deferred balances that serve as a measure for assessing the need for interim CGR rate adjustments. For instance, Mr. Oliver noted, the Company made upward adjustments to its normal weather sales forecasts every month from January 2017 through August 2017 and that, for the months of January through March, the adjustments were in the range of 6%. In later months, however, the adjustments varied wildly, from 13.5% to roughly 49%. Mr. Oliver contended that, although the variations were noted in the monthly GCR Deferred Balance Reports, nowhere was the methodology for determining the magnitude of the adjustments clearly documented.[68]

Mr. Oliver also noted that, with one exception, these adjustments had been applied exclusively to Sales Service volumes. That suggested that Transportation Service customers have no responsibility for variations in Unaccounted For Gas. Mr. Oliver's concern centered primarily upon the fact that no analytic support for these adjustments had been provided. Any assignment of upward adjustments to Transportation Service volumes, rather than solely to Sales Service volumes, could directly impact the Company's estimates of GCR costs and revenues, and later the Company's estimated end-of-October deferred balances.[69]

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[68] *Id*. at 10.
[69] *Id*. at 11.

V. National Grid's Reply Comments

On October 23, 2017, in response to Mr. Oliver's direct testimony, National Grid agreed to reallocate 100% of the demand costs associated with Crary Street deliveries to the DAC rather than the GCR.[70] Additionally, National Grid agreed to further clarify the costs incurred to maintain system pressure to other parts of the Rhode Island gas distribution system, and determine the extent to which such costs should be incorporated into the System Pressure Factor.

The Company stated that because the costs for leasing third-party portable LNG units will be temporary, the matter would not be addressed in the Company's rate case. Rather, the Company agreed to exclude these costs from the 2017-2018 GCR factors and, will instead, include them in the annual GCR reconciliation report and deferred balance in October 2018.[71]

In its reply, the Company acknowledged that the monthly deferred balance report with its published adjustments to the monthly weather sales forecasts did not provide the Division with all the information needed to determine if the adjustments are reasonable. The Company indicated that its overall intent in including the information was to better estimate the reconciliation balance at the end of the GCR year (October 31) and that instead, it will continue to analyze drivers of projected deferred balances.[72]

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[70] Letter from Robert J. Humm (Oct. 23, 2017); http://www.ripuc.org/eventsactions/docket/4719-NGrid%20Reply(Redacted)(10-23-17).pdf.
[71] *Id*. at 2.
[72] *Id*. at 3.

VI. Hearing

At the time of the hearing on October 17, 2017, the Company had not yet filed its responses to the Division's third set of data requests which pertained to the proposal for a substitute to the Cumberland LNG plant. The Division indicated, however, that it was amenable to moving forward with the hearing, but reserved the right to request an additional hearing after receipt of the data requests.[73] Additionally, the Company confirmed that its supplemental filing on September 29, 2017 had removed the Company's proposal to lease portable LNG tanks.[74] The Company advised the PUC that the parties had agreed the Company will be transferring 100% of the demand costs associated with deliveries to the Crary Street gate station from this GCR filing into the system pressure factor, as part of the DAC filing.[75] This transfer of $764,118 resulted in a decrease to the projected GCR factors and an increase to the DAC factors. Finally, the Company indicated that it was removing Attachment AEL-8 from the filing.[76]

The Division presented Mr. Oliver who testified that he reviewed the entire detail of the company's filing from the development of their gas costs for the projected GCR year to the forecasts used, and the analyses used in support of the Gas Procurement Incentive Program (GPIP) and Natural Gas Portfolio Management Plan (NGPMP) incentives as well as the monthly gas costs reconciliations.[77] Mr. Oliver indicated his concurrence and approval of the amended filing. He further explained that the Company's tariff does not

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[73] Hr'g Tr. at 8.
[74] *Id*. at 11.
[75] Docket 4708.
[76] *Id*. at 12.
[77] Hr'g. Tr. at 50-51.

require the company to file for interim rate relief once a 5% threshold is exceeded, but that the tariff permits such a filing.

On cross-examination by PUC staff, Mr. Oliver agreed that the prior year's under recovery of $14 million was significant, but was adequately explained. He also clarified that the parties had been using different terms: the company had been referring to adjustments to "unaccounted for gas" wherein Mr. Oliver stated that the more appropriate term was "unbilled gas revenue" or volumes. The significant point is that the numbers do not refer to lost gas at all, but rather reflect a billing lag issue.[78] Mr. Oliver confirmed that the Division and the Company are working closely together to monitor potential interim adjustments to the GCR factors and that the Company has been very responsive to his inquiries.[79]

In response to a Commission question about the Company's cost-benefit analysis cost/benefit analysis of its choice of its design day, which had been an issue in last year's GCR hearing, Mr. Oliver said he disagreed with the Company's analysis because it used overly generalized extrapolations from data in other jurisdictions. The Commission inquired further into the Company's forecasting methods and analyses. The Company demurred, noting that its next long-range forecast plan would be filed in March 2018 and would provide an opportunity to discuss forecasts in depth.[80]

VI. Commission Findings

At the close of the hearing, the Commission approved a High Load GCR Charge of $0.4859 per therm for Residential Non-Heating, Large High Load, and Extra Large High

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[78] *Id*. at 56.
[79] *Id*. at 59.
[80] *Id*. at 77.

Load classes. It approved a Low Load GCR Charge of $0.5291 per therm for Residential Heating, Small Commercial and Industrial, Medium Commercial and Industrial, Large Low Load, and Extra Large Low Load classes. Additionally, the PUC approved an FT-2 Marketer Demand charge of $8.8520 per dekatherm per month, a Storage and peaking charge for FT-1 Transportation customers of $0.7527 per Dekatherm, and a weighted average system capacity charge of $0.6168 per dekatherm of capacity for usage on and after November 1, 2017

The Commission found the Company's request for the $54,616 incentive on its GPIP and the NGPMP incentive of $1,225,321.10 to be fair and reasonable and approved the same. Finally, the PUC approved the BTU Conversion Factor of 1.029 per ccf. The Commission was satisfied that the rates proposed by National Grid and supported by the Division were properly calculated and would ensure that customers pay a just and reasonable rate.

Accordingly, it is hereby

(23468) ORDERED:

1. The Company's Motion for Protective Treatment is hereby granted for: Attachments NGC-1, NGC-2, NGC-4, NGC-1S, NGC-2S, NGC-4S, AEL-1, AEL-2, AEL-5, AEL-1S, AEL-2S, AEL-5S; Attachments 2, 7, and 8 of the NGPMP annual report; AEL-5 Revised, NGC-1 Revised, NGC-2 Revised, and NGC-4 Revised; Responses to Division 1-2A, 1-3A, and 1-9A; and Attachments 1-9B, 1-9C, 1-10A, 1-10B, 1-10C, 2-2A, and 2-2B.
2. The Division's Motion for Protective Treatment is hereby granted for Attachment GCR-2.

3. The Gas Cost Recovery factors of:
   a. $0.4859 per therm for Residential Non-Heating customers, Large High Load, and Extra Large High Load Factor customers and
   b. $0.5291 per therm for Residential Heating customers, Small Commercial and Industrial, Medium Commercial and Industrial, Large Low Load, and Extra Large Low Load Factor customers

   are approved for usage on and after November 1, 2017.
4. A Weighted Average System Capacity Charge of $0.6168 per Dth is approved for usage on and after November 1, 2017.
5. The Gas Marketer Transportation factors of:
   a. $8.8520 per Dth for the FT-2 Firm Transportation Marketer Gas Charge and
   b. $0.7527 per Dth for a Storage and Peaking Charge

   are approved for usage on and after November 1, 2017.
6. The incentive of $1,225,321.10 for the NGPMP, for the period April 1, 2016 through March 31, 2017, is approved.
7. The incentive of $54,616 for the GPIP, for the period July 2016 to March 2017, is approved.
8. The BTU factor of 1.029 per ccf is approved.
9. National Grid and the Division shall work together to address the costs associated with leasing third party portable LNG equipment and services in Cumberland and report their findings to the PUC for approval of the costs. National Grid shall reflect these costs in the reconciliation reports and deferred balances projected as of October 2018.

10. National Grid will no longer include adjustments in future monthly deferred balance reports; however, if the balance exceeds the 5% threshold in the tariff, National Grid will submit an interim filing to propose new GCR factors and/or provide an explanation in its deferred balance report as to why it is not proposing to submit an interim filing.

11. National Grid shall comply with the reporting requirements and all other findings and directives contained in this Report and Order.

EFFECTIVE NOVEMBER 1, 2017 IN WARWICK, RHODE ISLAND PURSUANT TO A BENCH DECISION ON OCTOBER 30, 2017. WRITTEN ORDER ISSUED MARCH 22, 2019.

PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

Marion S. Gold, Commissioner

Abigail Anthony, Commissioner

NOTICE OF RIGHT OF APPEAL

Pursuant to R.I. Gen. Laws §39-5-1, any person aggrieved by a decision or order of the Commission may, within seven days from the date of the order, petition the Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision or order.