STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT	**:**	
ELECTRIC COMPANY	**:**	**DOCKET NO. 4872**
d/b/a NATIONAL GRID	**:**	
GAS COST RECOVERY CHARGE	**:**	

REPORT AND ORDER

I. Introduction

On August 31, 2018, 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 annually adjust its rates for firm sales and the weighted average cost of upstream pipeline transportation capacity. The GCR allows the Company to recover the costs of gas supplies, pipeline and storage capacity, production capacity and storage, and purchased gas working capital. The GCR proceeding also permits the Company to account for supplier refund credits, capacity credits from off-system sales, and revenues from capacity release transactions.[2] The new GCR rates are effective each year on November 1. The original filing proposed a total bill annual decrease of approximately $40.14 for a typical residential heating customer using the equivalent of 846 therms per year.[3]

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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/4872page.html.
[2] The Narragansett Electric Company d/b/a/ National Grid R.I.P.U.C NG-GAS No 101, Section 2 Gas Charge, Sch. A, Sheet 1, Ninth Rev.(Sept. 1, 2018); https://www.nationalgridus.com/media/pdfs/billing-payments/rigas_tariff.pdf.
[3] The total monthly bill decrease, when including the Distribution Adjustment Charge decrease of $48.84 in Docket 4846, and the Gross Earnings Tax decrease of $2.75, will be 91.73, or a 6.5 % decrease from the 2017 Interim Factors which were effective on March 1, 2018.

On September 26, 2018, pursuant to the Company's effective gas tariff, RIPUC NG-GAS No. 101, Section 1, Schedule B, Sheet 1 (definition of British thermal unit (BTU) content factor), the Company filed its semi-annual BTU factor report[4] which proposed a BTU content factor of 1.030 for the period of November 1, 2018 through April 30, 2019.[5]

On October 18, 2018, the Division of Public Utilities and Carriers (Division) filed a memorandum authored by consultant, Bruce R. Oliver, together with a cover letter by Jonathan E. Shrag, the Division's Deputy Administrator, which made three primary recommendations: (1) disallow the Company's supplemental winter 2011-2018 supply contracts with ENGIE, pending a further review of the economic justification for those contracts; (2) disallow incremental costs incurred to replace supply formerly provided by the Cumberland LNG tank that was decommissioned in 2016, pending the completion of a prudency proceeding to examine the Company's maintenance practices in connection with the tank failure; and (3) approve an extension of time for the Division to examine, without prejudice, the prudency of a substantial increase over last year's GCR of the Company's supplier demand charges. At the hearing, Mr. Oliver also recommended that the Company's Long Range Plan (LRP) be developed more fully so that it has more direct relevance to the annual GCR filings.

On October 19, 2018, the Company filed rebuttal testimony challenging the legality and appropriateness of the Division's recommendations.[6] On October 24, 2018, the

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[4] National Grid's currently effective gas tariff, RIPUC NG-GAS No. 101, Section 1, Schedule B, Sheet 1 (definition of British thermal unit (BTU) content factor) requires National Grid to calculate the seasonal BTU content based upon the prior six-month experience for the equivalent season, which National Grid would then propose to take effect for the applicable May 1 and November 1. Such BTU content factors are used to convert volumetric meter readings into therms; Letter of Robert Humm (Sept. 26, 2018) ; http://www.ripuc.org/eventsactions/docket/4872-NGrid-BTU-SemiAnnualRept_9-26-18.pdf.
[5] *Id.*
[6] National Grid's Rebuttal Test.(Oct. 22, 2018); http://www.ripuc.org/eventsactions/docket/4872-NGrid-JointRebuttal-w-att(10-22-18).pdf.

Division submitted its surrebuttal testimony, with none of the contested issues having been resolved.[7] On October 25, 2018, the Commission conducted a hearing to examine the appropriateness of the Company's petition and address the Division's challenges. On October 30, 2018, the Commission held an Open Meeting and approved the 2019 Gas Cost Recovery factors and the BTU factor for the period of November 2018 through April 2019, as filed. The Commission first denied the Division's request to disallow the costs of the Engie contracts from the winter of 2017-2018. Next, the Commission ordered a prudency examination into the Company's maintenance practices for the now-decommissioned Cumberland LNG tank, to be concluded by April 1, 2019. The Commission also granted the Division additional time to April 1, 2019, to examine the prudency of the Company's supplier demand charges. Finally, the Commission ordered the Company and the Division to submit a joint memorandum in Docket No. 4816 outlining each of their recommendations for improving the LRP as it relates to the annual Gas Cost Recovery filing.

II. National Grid's August 31, 2018 Filing

Pursuant to the tariff, the GCR filing shall include all costs of firm gas, including, but not limited to, commodity costs, demand charges, hedging and hedging related costs, local production and storage costs and other gas supply expense incurred to procure and transport supplies, transportation fees, inventory finance costs, requirements for purchased gas working capital, all applicable credits, taxes, and deferred gas costs.[8] The tariff requires

[7] Test. of Bruce Oliver (Oct. 24, 2018); http://www.ripuc.org/eventsactions/docket/4872-DIV-Oliver(10-24-18).pdf.
[8] The Narragansett Electric Company d/b/a/ National Grid R.I.P.U.C NG-GAS No 101, Section 2 Gas Charge, Sch. A, Sheet 1, Ninth Rev.(Sept. 1, 2018); https://www.nationalgridus.com/media/pdfs/billing-payments/rigas_tariff.pdf.

that the Company calculate the gas charges separately for Sales Customers (a high load rate group and a low load rate group) and Firm Transportation (FT) customers (marketers).[9] The gas charges to sales customers consist of two components; fixed costs and variable costs. The cost calculation includes an adjustment for an uncollectible percentage of 1.91% as approved in Docket No. 4770. These charges are subject to the Rhode Island Gross Earnings Tax, as set forth in Section 1, Schedule C of the gas tariff.

In support of its filing, National Grid submitted the prefiled testimonies of Nancy G. Culliford, Manager of Gas Supply Planning for National Grid USA Service Company, Inc.; (Service Company); Elizabeth D. Arangio, the Director of Gas Supply Planning for the Service Company;[10] Ann E. Leary, Manager of New England Gas Pricing for the Service Company; Theodore E. Poe, Jr., Principal Gas Regulatory Specialist for the Service Company; and John M. Protano, Manager of Origination and Price Volatility Management in the Energy Procurement organization of the Service Company.[11]

III. National Grid's Prefiled Testimony

A. Nancy G. Culliford and Elizabeth D. Arangio- Joint Testimony

1. Consumption projections

The Culliford/Arangio testimony provided support for the estimated gas costs, assignment of pipeline capacity to marketers, other issues relating to the Company's proposed 2018-2019 factors, and modifications made to National Grid's portfolio for the

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[9] *Id.*

[10] Ms. Culliford's testimony and Ms. Arangio's testimony were submitted as joint testimony and shall be referred to as Culliford/Arangio testimony.

[11] Joint Test. of Ann E. Leary and Elizabeth D. A'Rangio (Aug. 31, 2018); http://www.ripuc.org/eventsactions/docket/4872-NGrid-Book%201-4872-GCR%202018%20(R)%20(8-31-18).pdf.; Test. of John Protano (Aug. 31, 2018); http://www.ripuc.org/eventsactions/docket/4872-NGrid-Book%202-2018-RI-GCR-Protano(8-31-18).pdf.

2018-19 GCR period.[12] Ms. Culliford and Ms. Arangio 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, 2018 and the difference between the futures contract purchases under the Gas Procurement Incentive Plan (GPIP) as of August 2, 2018 and the August 2, 2018 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). They reported that overall, the August 2, 2018 NYMEX strip is an average of $0.164 or 5.6% lower compared to the July 31, 2017 NYMEX strip.[13]

The Culliford/Arangio testimony asserted that the Company had planned for and contracted for the forecasted volume of 390,227 decatherms (Dth) to meet design day load requirements for November 2018 through October 2019, an increase of 32,219 Dth or 9% from last year. To meet design heating season load requirements for November 2018 through October 2019, the Company had planned for and contracted the forecasted volume of 29,676,936 Dth which was an increase of 11% over the 2017-2018 projected design heating season. The design year load requirement for November 2018 through October 2019 was a projected volume of 41,521,561 Dth, an increase in design year load requirements over the 2017-2018 year, of 10%.[14]

2. Cost Projections

The Culliford/Arangio testimony described how the Company uses a SENDOUT model to calculate projected gas costs. The SENDOUT model performs a dispatch

[12] Culliford/Arangio Direct Test. at 5 (Aug. 31, 2018).
[13] *Id*. at 7.
[14] *Id*. at 7-8.

optimization of the entire Rhode Island portfolio of gas supply, pipeline transportation, underground storage, and peaking supplies to calculate projected gas costs. The pricing of pipeline services is based directly on the pipeline tariffs and rates in effect as of August 1, 2018. For purchases at locations other than the Henry Hub, the model uses the expected basis differential to the Henry Hub process, to determine the expected difference or basis.[15]

The Culliford/Arangio testimony outlined the two gas cost components for the GCR: (1) Supply Fixed Costs, which include purchase, storage, or delivery of firm gas including pipeline and supplier fixed reservation costs, demand charges, and transportation fees; and (2) Supply Variable Costs, includes all variable costs of firm gas, including but not limited to commodity costs, taxes on commodity, other gas supply expenses incurred to transport and store the gas, and inventory commodity costs.[16] The testimony described how the Company calculated 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. Finally, the cost of transportation on the pipeline is added.[17]

3. Gas Supply Portfolio

Ms. Culliford & Ms. Arangio explained that National Grid would continue to operate its portfolio similarly to its operation in the 2017-2018 GCR period. They 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. They noted that on most days the Company is able to purchase less expensive supplies on the Texas Eastern

[15] *Id*. at 10.
[16] *Id.* at 11. Supporting detail for the gas costs was attached to the testimony as Attach. NGC/EDA-1.
[17] *Id*. at 12.

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. These less expensive supplies can be accessed by the Company without incurring any additional fixed costs.[18]

4. Transportation Capacity Portfolio

The Company's transportation capacity portfolio includes numerous contracts for gas delivery. The total capacity of the design year portfolio is 41,521,561, an increase of 3,767,030 Dth. over the 2017-2018 season.

a. Firm Gas Transportation – Tennessee Agreements (2)

The Company's first firm transportation agreement stems from a commitment in the Tennessee Northeast Energy Direct (NED) project for 20,000 Dth per day of firm pipeline capacity to meet forecasted requirements. The NED project was cancelled, but the Company was able to contract with Tennessee to replace the capacity with a transportation agreement for 20,000 Dth per day. The with a primary receipt point was at the interconnect with ENGIE Gas & LNG LLC (ENGIE) for delivery to the Company's citygate in Cranston, Rhode Island. This contract originally provided a phase-in of the maximum daily quantity (MDQ) of 5,000 Dth in 2018, 10,000 Dth in 2019 and 20,000 Dth in 2020. However, because of increased demand, the Company was able to negotiate an acceleration of the of the phase-in to secure 15,000 Dth per day, effective November 1, 2018, with a receipt point of Everett.[19]

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[18] *Id.* at 13.
[19] *Id*. at 15.

The second firm transportation agreement with Tennessee was for 24,000 Dth per day, with primary receipts allocated between Dracut (14,000 Dth/day) and Everett (10,000 Dth/day). Primary delivery under this contract was to the Lincoln citygate. This transportation contract was designed to cover supplies lost from the decommissioning of the Company's Cumberland LNG tank in the summer of 2016. After the decommissioning, the Company executed a one year agreement with Tennessee which contained a "right of first refusal" for capacity for one additional year. The right of first refusal was exercised for the period November 1, 2017 through October 31, 2018. The Company then entered into the instant agreement with Tennessee for a twenty-year period commencing November 1, 2018.[20]

b. Portland Agreement

On August 31, 2017, the Company executed a precedent agreement with Portland for the Portland Xpress Project which, once fully phased in, would allow the Company to supply 29,000 Dth per day of its Dracut receipt point entitlements on Tennessee using supplies from Dawn, Ontario via transportation agreements with Union Gas, TransCanada, and Portland. On April 20, 2018, Portland filed an application with the Federal Energy Regulatory Commission (FERC) to satisfy the requirements of Phase I of the Portland Xpress Project and requested approval by September 30, 2018 to achieve an in-service date of November 1, 2018. Subject to receipt of such approval by the FERC, effective November 1, 2018, the Company will have firm capacity entitlements of 11,037 Dth per day on the Union Gas pipeline system from Dawn to Parkway and 10,910 Dth per day on TransCanada from Parkway to East Hereford.[21]

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[20] *Id*. at 16.
[21] *Id*. at 17.

c. Tennessee Contract Consolidation

The Company consolidated three existing long-haul contracts with Tennessee into one contract with an MDQ of 29,335 Dth per day, with an end date of October 31, 2024.This consolidation created nomination and scheduling efficiencies, while not losing any firm entitlements.

d. Columbia Gas Transmission, LLC (Contract No. 31520)

In January 2018, the Company experienced a problem purchasing supply at Downingtown, the interconnect between Transcontinental Gas Pipeline Company, LLC (Transco) and Columbia Gas Transmission, LLCD (Columbia) due to pressure balancing between the two pipelines. As a result, the Company sought to switch to a more reliable and liquid receipt point. After analyzing various options, the Company determined that the receipt point in Pennsburg, Pennsylvania would serve as a less-expensive and more liquid trading point. Therefore, on February 15, 2018, the Company amended its contract with an effective date of April 1, 2018.[22]

e. Dawn Capacity Path

The Company has a total firm commitment of 1,025 Dth per day on the Union Gas pipeline system, originating at the Dawn Hub in Ontario Canada with delivery into TransCanada at the Parkway Compressor Station in Ontario. Additionally, the Company has firm capacity entitlements of 1,012 Dth per day on the TransCanada pipeline system, delivered to the Company's distribution system using the Company's existing transportation contracts on the Iroquois and Tennessee pipelines.[23]

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[22] *Id*. at 18.
[23] *Id*. at 19.

f. Asset Management and Gas Supply Agreement

Ms. Culliford and Ms. Arangio reported that the Company had issued a Request for Proposal (RFP) for an Asset Management and Gas Supply Agreement (AMA) with an effective date of November 1, 2018, to provide a maximum daily quantity of 1,025 Dth. per day with a swing component for the months of November, 2018 and March 2019, and a baseload volume for the months of December 2018, January, 2019, and February 2019.[24] These supplies will be transported on the Company's Iroquois and Tennessee pipeline transportation capacity to the Company's citygates. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned capacity for its own account. In exchange, the Company will receive an asset management fee, which is then credited to the customers. At the time of filing this Plan, the Company was still negotiating an asset management services agreement.[25]

g. Portland Capacity Path from Dawn

On August 7, 2018, the Company issued an RFP for an AMA to manage the Canadian assets associated with this path for a term of one-year effective November 1, 2018. The RFP requested a MDQ of 11,037 Dth per day with a daily call for the months of November 2018 through April 2019. The supplies will be delivered to the Company's citygates via the Portland and Tennessee pipelines. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned Canadian capacity for its own account. In exchange, the Company will receive an asset management fee, which is then credited to the customers. At the time of

[24] *Id.*
[25] *Id*. at 19-20.

filing this Plan, the Company was still negotiating an asset management services agreement.[26]

h. Dracut Capacity Path

On July 26, 2018, the Company issued an RFP to purchase supply at Dracut, Massachusetts for a term of four months, December 2018 through March 2019. The RFP requested an MDQ of 17,700 Dth per day and a maximum seasonal quantity (MSQ) of 531,000 Dth. The Company will transport the volumes from the primary Dracut receipt point on the Tennessee contracts to the Company's citygates. At the time of filing this Plan, the Company was still negotiating a transaction confirmation to memorialize the trade.[27]

i. Firm Liquid service for LNG/ NGLNG

At the time the Plan was filed, the Company was in the process of evaluating offers to meet an annual contract quantity of 300,000 Dth with eight trucks per day. The Company previously entered into a precedent agreement for a term of twenty years for liquefaction services at NGLNG's currently-existing storage facilities located in Providence, Rhode Island. On June 25, 2018, the FERC issued its Environmental Assessment of the NGLNG project. The Company anticipated that a certificate of public convenience and necessity would be issued on or before September 23, 2018, which would allow for the facilities to be in service for the 2021 refill season.

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[26] *Id*. at 20.
[27] *Id*. at 21.

5. Marketer Capacity Assignments

The Company is required to provide pipeline capacity for Gas Marketers. [28] The Culliford/Arangio testimony represented that the Company had made available 35,258 Dth per day of capacity to marketers on seven different pipeline paths, with one change from these capacity paths from last year- the change from Downingtown receipt point to Pennsburg, as previously discussed. The testimony 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. The first step is to calculate the system average cost which was $0.7713. A one hundred percent load factor per unit value of $0.0020 for the Marketer reconciliation adjustment is then credited to arrive at the average pipeline cost of $0.7693 per Dth.[29] They also explained the calculation for the delivered cost for each path.[30]

B. Testimony of Ann E. Leary

Ann E. Leary, Manager of New England Gas Pricing provided testimony to propose GCR factors for firm sales service and transportation service.[31] 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, 2018 through October 31, 2019 period. For the twelve-month period ending October 31, 2019, Ms. Leary stated projected gas costs for the Company's firm sales customers were approximately $161.4 million. She identified other costs and credits

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[29] Culliford/Arangio Test. at 27.

[30] *Id*. at 28; Attach. NGC/EDA-4.

[31] Leary Direct Test. at 2 (Aug. 31, 2018).

that, when added to the costs for the firm sales customers, would total $183.5 million in net costs necessary for the Company to collect.[32]

Ms. Leary explained that the Amended Settlement Agreement in Docket No. 4770, the Company made the following adjustments to components of the GCR factors: (1) reduced the uncollectible percentage used to gross up the GCR factors from 3.18 percent to 1.91 percent; (2) updated the fixed and variable LNG Operation & Maintenance (O&M) costs from $572,581 and $572,694, respectively, to $829,823, and $302,244, respectively; (3) increased the number of days lag used to calculate the gas working capital from 21.51 days to 32.92 days; and (4) updated the weighted average cost of capital and cost of debt from 7.26 percent and 2.58 percent, respectively, to 7.15 percent and 2.42 percent, respectively, used in both the working capital and inventory finance calculations.[33]

1. Fixed Costs

Ms. Leary explained that the Fixed Cost component includes all Fixed Costs related to the purchase, storage, and delivery of firm gas for both Low Load and High Load factor customers. She explained the derivation of the component that resulted in total Fixed Costs of $81.3 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 Low Load group and the High Load group. She proposed a GCR Fixed Low Load factor of $3.0728 per Dth and a GCR Fixed High Load factor of $2.1496 per Dth.[34]

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[32] *Id.* at 4.
[33] *Id.* at 5.
[34] *Id.* at 7.

This year, when calculating the fixed costs, the Company did not allocate any demand costs to the Company's Distribution Adjustment Charge (DAC) filing in Docket 4648. In recent years, there had been an allocation for one hundred percent of the gas costs associated with the Company's Crary Street gate station for system pressure. However, the parties have now decided that because all Company gate stations provide inlet pressure to the Company's distribution system, the Company will recover the costs associated with system pressure through the GCR, for all citygates.[35]

Ms. Leary explained that the Company calculated a 2017-2018 reconciliation credit to Marketers of $17,803, as shown in Attachment AEL-7, Page 1, 17 Line (22). The calculation was performed in accordance with a Settlement Agreement in Docket No. 4199. Additionally, the Company credited $6,851 for 2016-2017, as depicted on Attachment AEL-7, Page 3, Line 48.

Ms. Leary described the calculation of the design sales forecast. She indicated that the Company calculated the monthly design sales forecast by applying a monthly heat factor to the monthly design degree days. The monthly heat factor was computed by dividing the heating component of the normal sales (normal sales less monthly base use) by normal degree days for each month during the period November 2018 through March 2019. To compute the monthly design sales, the Company summed the monthly base use and the product of the monthly heat factor multiplied by the monthly design degree days.[36]

2. Variable Costs

The Company's variable cost component includes all variable costs of gas such as commodity costs, supply-related LNG O&M, working capital, inventory finance costs,

[35] *Id*. at 8.
[36] *Id*. at 11, Attach. AEL-1, p 14-16.

pipeline refunds, and deferred cost balances. The total estimated variable cost for the period November 2018 through October 2019 is $102,211,195. The variable costs are divided by the projected throughput to obtain a variable cost factor of $3.8346 per Dth[37]

3. Deferred Balance

On Attachment AEL -1, page 7, Mr. Leary presented the total estimated deferred balance for October 31, 2018 as an under-recovery of $23,353,322. This deferred balance was incorporated into the proposed GCR factors in this filing for the period November 1, 2018 through October 31, 2019.

4. FT-2 Rates

Ms. Leary presented a proposed FT-2 marketer demand rate of $17.0642 per Maximum Daily Quantity (MDQ) in Dth/month and the Storage and Peaking charge of $0.01648 per therm for FT-1 firm transportation customers returning to Transitional Sales Service (TSS). She also submitted capacity assignment percentages for the Low Load and High Load factors to be used in the determination of pipeline, underground storage, and peaking capacity for Marketers.[38] The FT-2 rate design separates storage costs into two components: : (1) the FT-2 Demand rate designed to recover the fixed costs associated with storage and peaking, which the Company is submitting for approval in this filing; and (2) the FT-2 Variable rate that is designed to recover variable underground storage costs, as well as the associated commodity costs and loss factors associated with pipeline contracts to bring the gas from storage to the citygate.[39]

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[37] *Id*. at 11, Attach.AEL-1, Page 3, Line (11).
[38] *Id*. at 14, Attach. AEL-6.
[39] *Id*.

Ms. Leary reported negative sales of 1,505 dekatherms for the period April 2017 through March 2018, as follows: (1) TSS Large Low Load Factor customers (Line (16)) during the month of June 2017; (2) Firm Transportation Service FT-2 Extra Large Low Load Factor customers (Line (47)) during the month of September 2017; and (3) Firm Sales Residential Non-Heating Low Income customers (Line (3)) during the month of October 2017.[40]

5. Bill Impact

Ms. Leary presented a combined bill impact to customers for the GCR factors and the DAC factors: for an average residential heating customer using 846 therms per year, the bill would decrease 6.5% on an annual basis.[41]

C. Testimony of Theodore E. Poe, Jr.

Mr. Poe's testimony supported the underlying retail and wholesale forecasts of natural gas customer requirements 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 provided 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 volume forecast 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.[42]–After determining the retail forecast, Mr. Poe explained that it is adjusted for billing lag and

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[40] *Id*. at 15.
[41] *Id*. at 17.; This overall decrease is comprised of a decrease of $40.14 from the proposed GCR factors; a decrease of $48.84 from the proposed DAC factors, for which the Company submitted a supplemental filing on August 31, 2018 in Docket No. 4846; and a decrease of $2.75 in Gross Earnings Tax.
[42] Theodore E. Poe, Jr. Direct Test. at 4-5 (Aug. 31, 2018); http://www.ripuc.org/eventsactions/docket/4872-NGrid-Book%201-4872-GCR%202018%20(R)%20(8-31-18).pdf.

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.[43]

Mr. Poe explained that the Company's forecast began with a retail level forecast of each of its internal rate codes. The Company forecasted the meter count and use per customer for each rate code which is then used to calculate the volume forecast. The Company also calculated an "unaccounted for" gas percentage.[44] Mr. Poe further explained that seventy-three 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 39,687,032 MMBtu indicated a 2.9% increase over the last year's total retail forecast, and a Commercial/Industrial Transportation decrease of 3.7%.[45] Wholesale sales volume growth is forecasted at 29,432,358 MMBtu for the period November 2018 through October 2019, an increase of 10.5% over last year.[46] Mr. Poe reported 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 evaluate the cost of

[43] *Id.* at 5.
[44] *Id.*
[45] *Id.* at 8.
[46] *Id.* at 9.

maintaining the resources necessary to meet design-level demand versus the cost to customers of experiencing service curtailments; (3) the Company identifies design standards that would maintain reliability at the lowest cost.[47]

D. Testimony of John M. Protano

Mr. Protano discussed the results of the Gas Procurement Incentive Plan (GPIP)[48] for the period April 1, 2017 through March 31, 2018 and the results of the Natural Gas Portfolio Management Plan (NGPMP) for April 1, 2017 through March 31, 2018.

1. GPIP

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. 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 ten percent 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 twenty percent of the total costs savings. For transactions executed between one and four months, the incentive payment to the Company is five percent, regardless of total costs savings.

[47] *Id*. at 10-11.

[48] The Gas Procurement Incentive Plan 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.

The Company calculated a total incentive of $17,789, which Mr. Protano proposed be granted in full.[49]

2. NGPMP

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 $4,495,089.54 in savings from April 2017 through March 2018, $3,996,071.64 of which customers would receive. Mr. Protano noted that the Company does not include any revenue from its Asset Management Agreement (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. The Company requested approval of a NGPMP incentive of $499,017.91 for the April 2017 through March 2018 period.[50]

IV. Division of Public Utilities and Carriers

On October 18, 2018, the Division filed a memorandum from its consultant, Bruce R. Oliver, together with a cover letter by Jonathan E. Shrag, the Division's Deputy Administrator, outlining its concerns and recommendations. The Division was concerned that the Company failed to adequately justify certain supply contracts and the impacts of the premature decommissioning of the Cumberland LNG tank. The Division opined that there was inadequate time to review the decommissioning issues within the scope of the GCR docket. Mr. Oliver also highlighted the fact that a major driver of the Company's

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[49] Protano Direct Test. at 5.
[50] *Id*. at 7-8.

costs for the 2018-2019 year were deferred gas costs of approximately $23 million from 2017-2018.[51]

Mr. Oliver noted that the Company's Fixed Costs (net of Capacity Release to marketers) were estimated in the 2017-2018 year (Docket No. 4719) to be $53.3 million. In the current filing, the Company projected $81.1 million for Fixed Costs, a year-over-year increase of $27.8 million or 52%.[52] He expressed concern that the Company's fixed cost commitments represented nearly half of the Company's overall gas supply and storage costs, when just two years ago, the Company's fixed cost commitments represented only 24.6% of its annual gas cost recovery requirements.[53]

Mr. Oliver expressed trepidation that the Company's 7.7% increase in Variable Costs was the first increase in the Company's Variable Gas Supply and Storage Costs in a decade and that it occurred at a time when the NYMEX strip prices for natural gas have decreased by 5.6%.[54] He argued further that the because the Company's interim rate adjustment from Docket No. 4719 did not become effective until March 1, 2018, the effective increases for various rate classes were actually higher than portrayed by National Grid.[55] Moreover, he predicted that residential customers would see a 13.5 % annual increase for 2018-2019 if the proposed GCR charges were approved.[56]

Mr. Oliver elucidated his concerns about the absence of comparative cost information from the 2018 GCR or from the Company's 2018 Long-Range Plan (LRP). With cost information from the 2018 GCR, the Division and Commission could assess the

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[51] Direct Test. of Bruce R. Oliver (Oct. 16, 2018); http://www.ripuc.org/eventsactions/docket/4872-DIV-Oliver-Redacted(10-18-18).pdf.
[52] *Id*. at 11-12.
[53] *Id*. at 12.
[54] *Id*. at 13-14.
[55] *Id*. at 15.
[56] *Id*. at 16.

overall costs of alternative gas supply portfolio configurations. He argued that the 2018 LRP's SENDOUT model was premised on a single set of portfolio assumptions and that nothing in the plan examined the manner in which the Company's total gas costs would differ under any alternative set of fixed costs assumptions.[57] He further opined that the Company's gas supply planning lacks sensitivity analyses with respect to the uncertain weather conditions in which it must operate.

Mr. Oliver alleged that the Company's strategy of fixed cost commitments, which he described as extremely expensive, uneconomic insurance policies, is most beneficial to the Company. He alleged that the Company's reliance on this strategy essentially eliminates the Company's responsibility for economically planning its gas supply resources.[58] Mr. Oliver noted that the Company's current fixed cost commitments focus on very low probability and low load factor. This approach results in far higher costs that differ substantially from past commitments which were focused on high load factors. He also criticized the Company's planning as inappropriately focused on only normal weather and design, instead of exploring a probability weighted average of weather outcomes.[59]

Mr. Oliver concurred with the accuracy of the Company's computations which showed an aggregate deferred gas cost balance as of March 31, 2018 of $43,080,683. This aggregate balance was comprised of a net of $45,495,738 under-recovery of variable costs and a $2,415,056 over-recovery of fixed costs.[60] He argued that the Commission should direct the Company to remove the fixed costs associated with payments made to ENGIE

[57] *Id*. at 22.
[58] *Id*. at 24.
[59] *Id*. at 26.
[60] *Id*. at 27.

during the winter of 2017-2018 because those supplemental contract costs were not approved in the original 2017-2018 GCR filing.[61]

Mr. Oliver also opposed approving incremental costs for gas supply that resulted from the closing of the Cumberland LNG tank. He opined that a prudency investigation into the Company's maintenance practices on the LNG tank was warranted. He contended that there was simply insufficient time within a GCR proceeding to undertake such an examination.[62]

As for the requested GPIP and NGPMP incentive payments, Mr. Oliver concurred with the Company's mathematical computations, but questioned the on-going effectiveness of each of these programs. He noted that since 2016, the NGPMP benefits to ratepayers have plummeted 67.5 % from a peak of nearly $12.3 million to $4.4 million. He stated that substantial losses of ratepayer benefits at a time when the Company has increased its fixed cost commitments will further exacerbate the rate impacts of the Company's fixed cost commitments.[63]

V. National Grid's Rebuttal

On October 22 2018 National Grid filed rebuttal testimony which argued: (1) that the Company's fixed cost commitments, including supplier demand charges were reasonable; (2) the ENGIE contract costs should not be excluded from recovery; and (3) the cost to replace LNG supply lost from the decommissioning of the Cumberland LNG tank should not be excluded from recovery.

[61] *Id*. at 28.
[62] *Id*. at 31.
[63] *Id*. at 37.

VI. Hearing

At the hearing on October 25, 2018, both National Grid's and the Division's various Motions for Protective Treatment[64] were granted and, after ensuring no objection, all exhibits were marked as full exhibits.[65] Mr. Humm presented Ms. Leary, Ms. Culliford, Mr. Poe, Mr. Protano, and Mr. Stephen Greco, Director of Pressure Regulation, as a panel. All the witnesses adopted their prefiled testimony and sponsored data request responses.[66]

Ms. Arangio explained that the increase in gas fixed cost recovery was due to a significant increase in the Company's planning load requirements and market conditions. She reported that during the winter in 2017-2018, the Company experienced six of the top ten SENDOUT days in the Company's history. As a result, she argued that the Company had no choice but to procure incremental resources for the upcoming year.[67] She opined that the Company's decision in making these purchases were necessary and prudent. She indicated that gas for Rhode Island is delivered via two interstate pipelines, the Tennessee and the Algonquin - both of which are constrained. When the Company determined that it did not have enough resources in the gas portfolio, it issued RFPs to purchase the incremental supplies.[68] These supplies were very expensive, but necessary.

On cross-examination by PUC staff, the Company explained that by following its rule curve, a design model for supplies, it determined that LNG supplies needed replenishment in early January 2018 because supplies were down to thirty percent. The

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[64] Hr'g Tr. at 5-6.
[65] *Id.* at 5.
[66] Mr. Greco made three minor typographical corrections to words in his testimony. (Hr'g. Tr at 29) No other witnesses made any changes to their prefiled testimony or sponsored exhibits.
[67] Hr'g. Tr. at 51.
[68] *Id.* at 55.

Company replenished 250,000 Dths of the 356,000 dekatherms that had been consumed since November 1, 2017.

The Company vigorously defended its decision to go to market to purchase incremental fixed cost supplies that it forecasted as necessary for the 2018-2019 winter. Ms. Arangio noted that the Company has participated in different projects to provide incremental capacity over the past several years and underscored the fact that the existing pipelines are severely constrained during the winter months. Additionally, she related that for the very first time in New England, suppliers failed to deliver contracted supplies. She argued that it would be imprudent for the Company to fail to plan for design weather standards. [69]

On cross-examination, Mr. Oliver clarified that the Division had backed away from its original request that the PUC deny the fixed costs of incremental supply to replace the peaking supplies formerly provided by the Cumberland LNG plant. He indicated that the Division sought a prudency review, with the opportunity for the Division to request disallowance at the end of that review.[70] He expressed concern that these costs have been imposed on ratepayers prematurely, due to the plant's removal being premature and unscheduled.[71]

Mr. Oliver expressed frustration with the gas supply LRP as it interacts with the GCR process and what he described as the LRP's lack of relevance. He offered some suggestions on how the LRP could be improved to add more relevance to the GCR process. He reported that while the Company and the Division have had interactions on the LRP,

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[69] *Id*. at 71.
[70] *Id.* at 171.
[71] *Id*.

there is no mechanism to resolve disagreements that arise. He opined that the LRP was seriously lacking in terms of identification of the plan's costs, including incremental costs and the financing of alternative projects. He also claimed that the LRP was not complete because it showed significant unserved load under every scenario over a ten-year period - whether it's for design year, peak day, design winter or normal winter.[72] He asserted that a fully developed plan would at least provide estimates of alternative sources of supply.

Mr. Oliver criticized the way the Company updated its LRP because the Company did not provide any work papers on how the update was performed. According to Mr. Oliver, the Division requested information, but was told the Company had nothing to provide to him.[73]

He claimed that there needs to be a better assessment of peak requirements and more explicit cost information. He indicated that additional planning alternative should be examined, including contracting for more pipeline capacity, greater access to more liquid markets for spot gas purchases, expansion of LNG capabilities and changes in the GPIP and NGPMP.[74] He questioned whether it is necessary to have five or ten year commitments to reservation charges if, in three or five years, there could be another LNG tank in place that would perform the same function, but at a lower cost.[75] He further challenged whether the Company's current modeling was adequate to answer whether an early winter cold snap really necessitated the level of additional procurement that was secured during the past heating season.

[72] *Id.* at 175.
[73] *Id*. at 179.
[74] *Id*. at 180, 184.
[75] *Id*. at 187.

Mr. Oliver recommended that the GCR be an expedited proceeding with far shorter timeframes for responses to the Division's data requests. He stated that such a process would be far more in line with how similar cases are handled in other jurisdictions.[76] Although he did not necessarily favor creating a standardized list of items for the GCR filing, he did think that it was critical for the Company to be providing economic justifications for their purchasing decisions. He did not think that the Company had demonstrated that it had evaluated a reasonable range of alternatives as to the current supply procurement plan or demonstrated why the chosen resource was a reasonable selection. However, he did not recommend that the Commission disallow the requested rates.[77] He suggested, instead, that the Commission permit the rates to go into effect, but to provide the Division with additional time to review and litigate, if necessary, the costs of the ENGIE contracts. He identified April 1, 2019 as an end date for the Division's review because that would be when the Company would begin making supply purchase decisions for the following winter heating season.[78] Mr. Oliver also suggested that the Company investigate the development of demand side management options to help reduce peak load.

VII. Commission's Findings

On October 29, 2018, the Commission conducted an Open Meeting to decide all pending factors and issues. The Commission approved a High Load GCR Charge of $0.6100 per therm for Residential Non-Heating, Large High Load, and Extra Large High Load classes. It approved a Low Load GCR Charge of $0.7041 per therm for Residential

[76] *Id*. at 197.
[77] *Id*. at 200.
[78] *Id*. at 203.

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 $17.064 per dekatherm per month, a Storage and peaking charge for FT-1 Transportation customers of $1.6478 per Dekatherm, and a weighted average system capacity charge of $0.7693 per dekatherm of capacity for usage on and after November 1, 2018.

The Commission found the Company's requests for the $17,789 incentive on its GPIP incentive and the NGPMP incentive of $499,017.91 were properly calculated in accordance with those programmatic requirements, as well as fair and reasonable, and approved the same. Finally, the PUC approved the BTU Conversion Factor of 1.030 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.

The Commission also reviewed, discussed, and addressed the Division's four specific recommendations.[79] The first recommendation related to the costs associated with two of the Company's supply contracts (referred to as the ENGIE contracts). The Division argued that the contracts, which were first referenced in an interim proceeding within Docket No. 4719, the 2017 GCR, were not economically justified by the Company and that recovery of these costs should be excluded from the GCR, pending a more in-depth investigation by the Division. At the commencement of the hearing, the Division withdrew its objection, without prejudice, to the costs flowing through the GCR at this time. However, the Division sought time to conduct further investigations into these contracts.

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[79] Division Memo (Dec. 18,2018); http://www.ripuc.org/eventsactions/docket/4872-DIV-RecommendationLletter(10-16-18).pdf.

In denying the Division's request, the Commission noted that the existence of these contracts was known and referenced in the 2017 GCR interim proceeding. The company explained that extreme cold weather and corresponding increases in customer load stressed the Company's LNG inventory levels and put them well below the LNG storage rule curve levels. The company entered into the ENGIE contracts to bring its LNG supply back in line with its LNG rule curve. Responses to the Division's data request on these contracts were received by the Division prior to the February 2018 hearing on the Interim GCR and the Division did not sound any alarms about these contracts. In fact, the Division specifically recommended that the Commission approve the Interim rate filing which included these contracts.[80] The Commission finds that to deny cost recovery now would be arbitrary.

The Division's second recommendation centered on the incremental gas costs incurred after the Cumberland LNG tank decommissioning in late 2016. The Division originally sought the exclusion of incremental costs in the GCR and requested that the Commission open a docket to examine the prudency of the Company's maintenance practices in connection with the tank failure. Again, at the commencement of the hearing, the Division modified its position and stated that the costs could be permitted to flow through the GCR, but without prejudice to the Division to raise the issue in next year's GCR, after a prudency investigation has been completed. In its review, the PUC noted that the Company was assessed and paid a civil penalty to the Division of $160,000 in association with the decommissioning of the tank.[81] Additionally, in the last Gas

[80] Memo from Bruce Oliver at 3 (Feb.23, 2018); http://www.ripuc.org/eventsactions/docket/4719-DIV-Memo-InterimGCR(2-23-18).pdf.

[81] This civil penalty issued by the Division does not necessarily equate to an admission of liability. The Commission retains its prudency review.

Infrastructure, Safety, and Reliability Plan (Gas ISR), Docket No. 4678, the Division indicated that its investigation into the decommissioning was ongoing and retained its right to recommend adjustments in the upcoming Gas ISR relating to this issue. The costs incurred by the Company to replace the gas that would have been supplied by the Cumberland LNG tank are not insubstantial.[82] The Commission voted to allow certain incremental costs incurred by the Company resulting from failure of the LNG tank in Cumberland, pending the findings of a separate proceeding to examine the prudence of the Company's maintenance practices in connection with the tank failure. By this motion, the Commission reserved its right to consider the prudency of any incremental costs as a result of the decommissioning of the LNG tank. The Division was ordered to conclude its investigation and report to the Commission no later than April 1, 2019.

The Division's third recommendation addressed the costs associated with the Company's so-called "Supplier Demand Charges." The Division was concerned about the substantial increase in these costs (over $23 million more than what was included in GCR rates last year). Further, the Division averred that the GCR proceeding does not allow enough time for a complete review. The Division did not object to these costs flowing through the GCR at this time but recommended that this flow-through not constitute a final decision on cost recovery. The Division requested the Commission further time to review these costs in the 2019 GCR, after the Division completes its review. The Commission voted to approve incremental fixed costs and allow further review of these costs to be examined, without prejudice to the Division recommending adjustments to the GCR in

[82] Confidential responses to Division Rata Request 3-1 and 3-2.

2019 relating to these fixed costs. The Division was directed to submit its recommendation to the Commission concerning these costs no later than April 1, 2019.

The Division's fourth issue was Mr. Oliver's assertion that the Company's LRP, as it impacts the annual GCR filings, was inadequate to fully inform the GCR filings. In his testimony before the Commission, Mr. Oliver highlighted a number of issues and argued that the Gas Long Range Supply Plan filed in March, 2018 in Docket 4816 required additional information for it to be an effective docket for the Commission's review of the Gas GCR. The Company concurred that improvement could be made in the LRP docket to create a positive impact upon the GCR proceedings, prospectively. Therefore, the Commission ordered the parties to file a joint memorandum by February 1, 2019 in Docket No. 4816 outlining each of their recommendations for improving the Long Range Gas Supply Plan as it relates to the annual Gas Cost Recovery filing. The memo shall specify areas or topics on which they do not agree and why.

Accordingly, it is

(23693) ORDERED:

1. The Company's Motion for Protective Treatment is hereby granted for: Attachments NGC/EDA-1, NGC/EDA-2, NGC/EDA-4, AEL-1, AEL-2, AEL-5, Responses to Division 1-7, 1-10, 1-12, 1-16, as well as Attachments Div. 1-10, Div. 1-13, Div. 1-14 and Div. 1-15.2-1, Div. 2-2. Div. 2-5, Div. 2-7 through Div. 2-10, Div. Div. 2-16, Div. 3-1, 3-2, 3-6 and Attachments Div.3-6-6 through 3-6-8, Div. 4-1, Div. 4-2, Attachment Div. 4-1. and Div.5-5.
2. The Division's Motion for Protective Treatment is hereby granted for Attachments DIV GCR-5 and DIV GCR-6.

3. The Gas Cost Recovery factors of:

    a. \$0.6100 per therm for Residential Non-Heating customers, Large High Load, and Extra Large High Load Factor customers and

    b. \$0.7041 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, 2018.

4. A Weighted Average System Capacity Charge of \$0.7693 per dekatherm is approved for usage on and after November 1, 2018.

5. The Gas Marketer Transportation factors of:

    a. \$17.064 per dekatherm for the FT-2 Firm Transportation Marketer Gas Charge and

    b. \$1.6478 per dekatherm for a Storage and Peaking Charge

    are approved for usage on and after November 1, 2018.

6. The incentive of \$499,017.91 for the Natural Gas Portfolio Management Plan, for the period April 1, 2017 through March 31, 2018, is approved.

7. The incentive of \$17,789 for the Gas Procurement Incentive Plan, for the period July 2017 to March 2018, is approved.

8. The BTU factor of 1.030 per ccf is approved.

9. The Division's request for additional time to review the prudency of the ENGIE contracts from the 2017-2018 GCR year is denied.

10. Certain incremental costs incurred by the Company resulting from the failure of the Cumberland LNG tank are allowed, pending the findings of a separate proceeding to examine the prudence of the Company's maintenance practices in connection with the

tank failure. In issuing this order, the Commission reserves its right to consider the prudency of any incremental costs as a result of the decommissioning of the LNG tank.

11. The Division's request for additional time to review the prudency of incremental fixed costs for the 2018-2019 GCR year is granted, without prejudice to the Division recommending adjustments to the 2019-2020 GCR relating to these fixed costs. The Division shall submit its recommendation to the Commission concerning these costs no later than April 1, 2019.
12. By February 1, 2019, the Company and the Division will submit a joint memorandum in Docket No. 4816 outlining each of their recommendations for improving the Long Range Gas Supply Plan as it relates to the annual Gas Cost Recovery filing. This filing will specify areas or topics on which they do not agree and why.

EFFECTIVE NOVEMBER 1, 2018 IN WARWICK, RHODE ISLAND PURSUANT TO A DECISION MADE AT OPEN MEETING ON OCTOBER 30, 2018. WRITTEN ORDER ISSUED OCTOBER 11, 2019.

PUBLIC UTILITIES COMMISSION

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Margaret E. Curran, Chairperson*

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Marion S. Gold, Commissioner

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Abigail Anthony, Commissioner

*Chairperson Curran was not available to participate in the decision.

NOTICE OF RIGHT OF APPEAL: Pursuant to R.I. Gen. Laws § 39-5-1, any person aggrieved by a decision or order of the PUC 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.