STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

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

REPORT AND ORDER

1. Introduction

On January 29, 2018, The Narragansett Electric Company d/b/a National Grid (National Grid or Company) submitted an Interim 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. National Grid's tariff provides that if the deferred gas cost balance exceeds five percent of the Company's annual gas cost revenue, the Company may request a change to its GCR factors.[2] In the current filing, the Company indicated that it was projecting a deferred cost balance as of October 31, 2018, at approximately $34.4 million or twenty-four percent of the total annual cost revenue. The Company proposed a change to the GCR factors to recover approximately $22.8 million of the deferred gas cost balance between March 2018 through October 2018 and to defer recovery of approximately $11.6 million for recovery during the November 1, 2018, through October 2019 GCR year.

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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/4719-NGrid-InterimGCR(1-29-18).pdf.
[2] RIPUC NG-GAS No. 101, Section 2, Schedule A, Part 1.2.

On February 22, 2018, the Division filed a memorandum from its consultant, Bruce R. Oliver, who recommended approval of the Company's request, but expressed several ratemaking, planning and policy concerns which will need to be addressed in the coming months. By the time that the PUC conducted a hearing on February 26, 2018, the deferred balance had risen from $34.4 million to $47.1 million. However, since the proposed increase to ratepayers to recover the $22.8 million between March and October 2018 was already 15.6%, the Company proposed deferring recovery of the additional $12.7 million, for a total of $24.3 million, to the 2018-2019 GCR year. Upon conclusion of the hearing, the PUC voted to approve the filing.

2. National Grid's January 29, 2018 Filing- Summary of Prefiled testimony

In support of its filing, National Grid submitted the prefiled testimonies of Nancy G. Culliford, Manager of Gas Supply Pricing; Ann E. Leary, Manager of New England Gas Pricing, Gas Pricing for National Grid USA Service Company, Inc.; and Stephen A. McCauley, Director of Wholesale Electric Supply and U.S. Commodity Hedging in the Energy Procurement division of National Grid USA Service Company, Inc.

Pursuant to the Company's Tariff, RIPUC NG-GAS No. 101, Section 2, Schedule A, Part 1.2, if a projected deferred cost balance exceeds five percent of the Company's annual gas cost revenue, the Company may file a request to adjust its GCR factors to eliminate or reduce this deferred balance. The Company projected that the deferred cost balance at the end of October 2018 would be approximately twenty-four percent of the annual cost revenue, and determined that an interim adjustment to the GCR factors was

warranted.[3] If the Company did not seek this increase in its GCR factors, the estimated deferred gas cost balance at the end of October 2018 would be $34.4 million.[4]

Ms. Leary explained that there were two major factors contributing to the substantial increase in the projected gas cost deferrals: (1) increases in actual and forecasted gas prices, and (2) significant increase in gas purchases due to the extremely cold weather at the end of 2017 and into early 2018. The gas forecast was based on the New York Mercantile Exchange (NYMEX) strip as of the close of trading on July 31, 2017. Since then, gas prices have escalated. The Company's actual commodity gas costs for November and December 2017 were approximately $15.2 million higher than forecasted.[5] The updated forecast for January 2018 through October 2018 is approximately $28.4 million higher than projected in the initial GCR filing.[6] The Company also updated its January 2018 sales volumes to reflect a billing lag for December 2017 deliveries. Finally, the Company is making updates to the GCR's working capital and inventory finance calculations because of the federal Tax Cuts and Jobs Act reduction of the corporate income tax rate to twenty one percent.[7]

Ms. Leary explained that the proposed factors are not intended to eliminate the full $34.4 million deferred balance by October 2018, but rather to recover approximately $22.8 million and defer the balance to next year's GCR, lessening the recovery impact on its customers. Had the Company sought to recover the full deferred amount, customers would have experienced a twenty-four percent total bill increase.[8] The Company decided that

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[3] Test. of Ann E. Leary at 3 (Jan. 29, 2018).
[4] *Id*. at 4.
[5] *Id*.
[6] *Id*. at 5.
[7] *Id*. at 6.
[8] *Id*. at 7.

mitigation of the bill impacts was in order and sought instead to limit the bill impacts to 15.6 % by deferring approximately $11.6 million of the deferred balance to the 2018-19 GCR. Ms. Leary further related that in 2014, the PUC approved a similar size adjustment to the GCR factors. Ms. Leary indicated that deferral of the full amount to the next GCR year would impact current and future customers unfairly through interest costs and by burdening the future customers with costs that they did not create.[9] She indicated that by adjusting the GCR factors, customers would avoid paying $245,000 in interest through October 31, 2018. Ms. Leary advised that the current GCR factors already include a deferred balance of approximately $13.5 million from the 2016-2017 GCR period.[10]

Ms. Leary explained that seven other Massachusetts gas distribution companies have also requested increases in their Peak Gas Adjustment Factors (GAFs) for similar reasons, with customer bill impacts ranging from a low of 6.6% up to 31 %. An average Rhode Island residential heating customer using 396 therms for period of March through October will experience a total bill increase of $94.84 or 15.6%.[11]

Nancy G. Culliford presented a chart comparing the Heating Degree Day design to actual Heating Degree Days for the weeks ending December 17, 2017, through January 14, 2018. The chart showed that for four out of five weeks, the weather was colder than normal and for three of the five, the weather was colder than the forecasted design weather.[12] Of significant note is that during the December 2017- January 2018 timeframe, the Company experienced six of the top ten highest sendout volumes in Company history within its

[9] *Id*. at Bates 10.
[10] *Id.* at Bates 11.
[11] *Id*. at Bates 13.
[12] Test. of Nancy Guilford at 3 (Jan. 29, 2018).

service territory.[13] The bitter weather caused increased customer usage, requiring the Company to purchase supplies over and above the portfolio, at significantly increased prices.[14] When pipeline supplies were exhausted, the Company had to use liquified natural gas (LNG) to meet requirements, decreasing the local LNG inventory supply to sixty-seven percent at the end of December, 2017, and to thirty-six percent by January 8, 2018.[15] This required the Company to purchase replenishment supplies. From December 9, 2017, through January 16, 2018, the Company purchased 0.858 billion cubic feet of gas (Bcf) supply. That represents seventy-six percent of the design forecast for firm customers for the entire 2017-18 season and 283% of the forecast for that period.[16]

Ms. Culliford explained that there have been two changes to the Company's gas supply portfolio since the initial GCR filing, both with an effective date of January 10, 2018: (1) the Company entered into an LNG Liquid Agreement with ENGIE Gas & LNG, LLC (ENGIE), and (2) the Company also entered into a Firm Combination Contract with ENGIE to be used as either liquid or vapor.[17] The ENGIE liquid agreement was required to replenish supplies that had fallen substantially below the design season rule curve and to ensure that LNG would be available for the remainder of the heating season. The Firm Combination Contract provides the Company with the right to purchase a maximum daily quantity (MDQ) of 10,000 million British Thermal Units (MMBtu) per day with a contract total of 150,000 MMBtus. The Company has the option, prior to April 1, 2018, to call on the MDQ as either vapor or LNG. This contract terminates on October 1, 2018. The

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[13] *Id*.
[14] *See* Chart, "Gas Daily Price for AGT, CG, TGP Z6 and TETCO M3 12/1/2017-1/16/2018" at Bates 56.
[15] Test. of Nancy Guilford at 5 (Jan. 29, 2018).
[16] *Id*.
[17] *Id*. at Bates 6.

Company also recalculated projected gas costs using the SENDOUT model results as shown in the initial GCR filing with updated pricing.[18]

Stephen A. McCauley explained the effectiveness of the Company's market area hedge strategy and the cost of gas resulting from the mid-winter cold snap. He explained that the market area hedge strategy was similar to ones approved by the PUC during three prior winters.[19] Mr. McCauley identified a net benefit of $7.5 million as a result of hedged purchases from the first sixteen days of January.[20] He further opined that the Company's hedging strategy effectively balances the risks and costs and provides some protection under more severe weather conditions, while not burdening customers with incremental costs in normal and warmer than normal winters.[21]

3. <u>Division of Public Utilities and Carriers February 22, 2018, Filing</u>

The Division of Public Utilities and Carriers (Division) submitted the testimony of Bruce R. Oliver, its consultant, who analyzed the Company's filing and made recommendations. He noted that the Company's incremental market purchases in the first sixteen days of January 2018 had an average price that was more than eight and a half times the anticipated average costs. These purchases added roughly $24 million to the Company's normal weather variable costs of gas. Additionally, another $5 million was slated for expenditures under the ENGIE contracts. Neither of these amounts were contemplated or accounted for in the approved GCR factors.[22] Mr. Oliver did not dispute National Grid's assertion that had the hedges not occurred, gas costs would have been

[18] *Id*. at 9.
[19] Test. of Stephen A. McCauley at 3 (Jan. 29, 2018).
[20] *Id*. at 6.
[21] *Id*. at 8.
[22] Division Memo at 2 (Feb. 22, 2018)

approximately $7.5 million higher and its projected deferred balance higher. Mr. Oliver concurred with the Company's approach to not defer recovery of the entire projected deficit to the 2018-2019 GCR year and recommended that the PUC grant the Company's request.[23] Mr. Oliver did, however, raise several ratemaking, planning, and policy concerns that he recommended should be addressed in greater detail, perhaps in the Company's Long-Term Gas Plan. These included: (1) whether the Company acted in a reasonable and prudent manner to minimize its costs for the procurement of incremental gas supplies, including costs for access to incremental gas supply resources; (2) the extent to which non-firm customers contributed to the Company's incurrence of costs of extremely high-priced purchases, and whether the existing rates and tariffs provide adequate compensation during periods of high demand and high area market prices; and (3) whether more of the costs should be recovered through the Company's "Fixed Cost Factor" as opposed to the "Variable Cost Factor."

According to Mr. Oliver, policy considerations that should be examined include: (1) contracting for additional pipeline capacity; (2) greater access to more liquid markets for spot gas purchases; (3) expansion of LNG storage capabilities; and (3) changes in the parameters of the Company's Gas Procurement Incentive Program (GPIP) and the Natural Gas Portfolio Management Plan (NGPMP). Regulatory policy options suggested for consideration by Mr. Oliver include: (1) encouragement of greater use of gas demand side management options; (2) greater penalties for marketers whose customers use gas in excess of the marketer's deliveries on high sendout days; (3) encouragement for customers to utilize interruptible gas services; and (4) development of curtailment plans under which

[23] *Id*. at 3.

non-essential gas uses could be curtailed during extremely high-priced periods for incremental market area gas purchases.[24]

4. <u>The Commission's Hearing</u>

By the time of the February 26, 2018, hearing, the deferred cost balance projected for October 31, 2018 had risen from an estimated $34.4 million to $47.1 million.[25] Ms. Leary explained that there were a few different causes for the increase in the projected deferred gas cost balance: (1) actual costs for gas purchases were about $3.1 million higher than forecasted for January; (2) revenues were approximately $5.5 million lower for the month of December; (3) an updated forecast for February through October projected an increase of approximately $900,000; and (4) NGPMP credits for the period of April 2017 through December 2017 were $3.1 million less than originally forecast.[26] She confirmed that she was comfortable with not adjusting the current request to recover more of the projected deficit via the 2017-2018 GCR. By deferring the recovery into the following GCR year, the costs can be spread over an entire year instead of eight months.[27]

Mr. McCauley confirmed that the Company's approved hedging plan did not call for hedging in December 2017, but that if it had, the cost would probably have been approximately $7 million. Although in hindsight, there might have been an incremental $1 million benefit by hedging, the Company did not seek to hedge because hedging absolutely results in incremental costs and the Company had benefitted by not hedging December's gas in the past few years.[28] The Company will continue to examine its hedging

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[24] *Id*. at 4-5.
[25] Hr'g. Tr. at 23.
[26] *Id*. at 34-36.
[27] *Id*. at 38.
[28] *Id*. at 30.

strategy closely for the upcoming season to ascertain whether hedging for December 2018 would be appropriate.

The Company will also be closely reviewing and formulating its future forecasts for purchases because the Company was required to purchase a significantly greater volume of gas over several days. Mr. McCauley also stated that pricing would have to be carefully reviewed. The Company has been forecasting price using what is known as a ninety-five percent confidence level. If the Company switched to a ninety-nine percent confidence level, the pricing would rise, which in turn would change the ratios used to evaluate the risks.[29] Mr. McCauley explained that the hedging pricing estimated cost in January at a substantially lower cost than was actually realized.[30] As the month moved on, the prices went down a bit, but the Company still spent a significant more amount of money on gas than it had forecast.

Commissioner Anthony inquired as to whether the Company had any plans to modify its forecasting and planning in a world that has been characterized by increasingly extreme weather. Mr. Poe explained that the Company is always reexamining its forecasting. He described three components of forecasting: (1) the design day standard, which is set for the highest throughput on a rare probability of occurrence; (2) the design year standard, to be utilized over an extended period of time with various gas resources so as to be able to provide continued service to customers over a colder than normal period; and (3) the cold snap analysis which looks at fourteen-day period of intense cold, and which is useful for testing what the Company's resource portfolio can withstand.[31]

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[29] *Id*. at 53.
[30] *See* Attach. SAM-1 at 25.
[31] *Id*. at 69-70.

Immediately following the hearing, the Commission approved a High Load GCR Charge of $0.7183 per therm for high load classes and $0.7614 per therm for low load classes. The Commission was satisfied with the Company's filing. Further, it concurred with the Division's conclusion, that the rates proposed by National Grid were properly calculated as well as just and reasonable.

Accordingly, it is hereby

(23261) ORDERED:

1. The Company's Motion for Protective Treatment is hereby granted.
2. The Gas Cost Recovery factors of: $0.7183 per therm for high load classes and $0.7614 per therm for low load classes are approved for usage on and after March 1, 2018.

EFFECTIVE AT WARWICK, RHODE ISLAND ON MARCH 1, 2018, PURSUANT TO A BENCH DECISION ON FEBRUARY 28, 2018. WRITTEN ORDER ISSUED AUGUST 24, 2018.

PUBLIC UTILITIES COMMISSION

*Margaret E. Curran, Chairperson

Marion S. Gold, Commissioner

Abigail Anthony, Commissioner

* Chairperson Curran did not participate in this matter.

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 (7) days from the date of the order, petition the Rhode Island Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision of order.