STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT	**:**	
ELECTRIC COMPANY	**:**	**DOCKET NO. 4647**
d/b/a NATIONAL GRID	**:**	
GAS COST RECOVERY CHARGE	**:**	

REPORT AND ORDER

On September 1, 2016, 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). 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 instant filing proposed a decrease in rates approved by the PUC earlier, in Docket No. 4576, for the period November 1, 2016 through October 31, 2017. The proposed rates realize an annual decrease of approximately $69.51 for a typical residential heating customer using the equivalent of 846 therms per year.

I. National Grid's September 1, 2016 Filing

In support of its filing, National Grid submitted the prefiled testimonies[1] of Elizabeth D. Arangio, Director of Gas Supply Planning for National Grid; Ann E. Leary, Manager of Gas Pricing for National Grid USA Service Company, Inc.; Theodore E. Poe, Jr., Manager of Gas Load Forecasting and Analysis; and Stephen A. McCauley, Director of Origination and Price Volatility Management in the Energy Procurement organization of National Grid USA Service Company, Inc. Ms. Arangio's testimony provided support

[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/4647page.html.

for the estimated gas costs, assignment of pipeline capacity to marketers, other issues relating to the Company's proposed factors, and modifications made to National Grid's portfolio for the 2016 GCR period.[2] 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 29, 2016 and the difference between the futures contract purchases under the Gas Procurement Incentive Plan (GPIP) as of July 29, 2016 and the July 29, 2016 NYMEX strip. The factors also reflect storage and inventory costs as of July 29, 2016 and the projected cost of purchasing gas ratably through the injection season as provided for in the Natural Gas Portfolio Management Plan (NGPMP). She noted that the current year's average NYMEX pricing was higher than it was the previous year.[3]

Ms. Arangio described how the Company uses a SENDOUT model to calculate projected gas costs. To minimize yearly supply costs, pricing, contract, and storage information are used to determine the dispatch of supplies.[4] Ms. Arangio explained 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, which include commodity costs, taxes on commodity, other gas supply expenses incurred to transport and store the gas, and inventory commodity costs.[5] Attached to her testimony, Ms. Arangio provided supporting detail for the gas costs.[6] She described how the Company calculates the delivered cost for a particular gas supply. Beginning with the NYMEX

[2] Arangio Direct at 3 (Sept. 1, 2016).
[3] *Id.* at 4.
[4] *Id.* at 5.
[5] *Id.* at 5-6.
[6] Arangio Direct, Att. EDA-2.

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.[7]

Ms. Arangio explained that National Grid would continue to operate its portfolio the way it had the prior year. She described the Company's various contracts and its plans regarding the existing HubLine and East-to-West capacity paths on Algonquin which will terminate on the in-service date of the Algonquin Incremental Market Expansion (AIM Project).[8] She discussed an April 29, 2016 incident that occurred with the Texas Eastern Transmission Company (Texas Eastern), causing a disruption in the Company's deliveries. She stated that National Grid was able to reroute most of its supply coming through the Delmont Compressor Station on the Penn-Jersey Line. However, full service was not expected to be restored until November 1, 2016. To avoid disruption during the winter months, National Grid issued an RFP seeking the option for a supply call at Texas Eastern/M3 for December 2016, January 2017, and February 2017 to address the potential expected level of interruption on Texas Eastern.[9]

Ms. Arangio discussed how the Company's Cumberland LNG facility was taken out of service for the 2016-17 winter season to address a temperature anomaly at the bottom of the tank. In response, National Grid had secured additional pipeline capacity on the Tennessee Pipeline for the gas year and planned to use portable LNG in order to meet forecasted peak day and peak hour requirements during the winter season.[10] She also provided that National Grid utilized its existing multi-year arrangement for liquid

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[7] Arangio Direct at 7-8.
[8] *Id.* at 8-10.
[9] *Id.* at 10-14.
[10] *Id.* at 14-15.

service for the 2017 off-peak refill season and expected to have its LNG facilities 100% full as of December 2016.[11]

Ms. Arangio identified steps that the Company had taken to address long-term portfolio risks. The first step was to enter into precedent agreements to secure capacity.[12] The second step was to execute long-term LNG Liquefaction Service Agreements.[13] She provided that, in response to Kinder Morgan providing notices of termination for its precedent agreements for the Northeast Energy Direct Project, National Grid was evaluating its existing options.[14]

Regarding marketer capacity assignments, Ms. Arangio represented that the Company had made available 35,258 decatherms (Dth) per day of capacity to marketers on seven different pipeline paths. 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 $0.6873 per Dth to the system average pipeline unit variable cost of -$0.3784 per Dth to derive the $0.3089 per Dth weighted average pipeline cost. She then added the weighted average pipeline cost to the 100% load factor per unit cost of $0.0030 for the marketer reconciliation adjustment to average pipeline cost of $0.3119 per Dth. She also explained the calculation for the delivered cost for each path.[15]

Ms. Leary provided testimony to propose GCR factors for firm sales service and transportation service.[16] She explained that the proposed GCR factors are load specific,

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[11] *Id.* at 15.
[12] *Id.* at 16-18.
[13] *Id.* at 19-20.
[14] *Id.* at 20.
[15] Arangio Direct at 21-23, Att. EDA-4.
[16] Leary Direct at 2 (Sept. 1, 2016).

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, 2016 through October 31, 2017 period. For the twelve-month period ending October 31, 2017, Ms. Leary stated projected gas costs for the Company's firm sales customers were approximately $116.9 million. She identified a number of other costs and credits that, when added to the costs for the firm sales customers, would total $117.9 million in net costs necessary for the Company to collect.[17]

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 $29.3 million to be allocated to and collected from ratepayers based on their proportion of design-winter use requirements. She provided 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 $1.1412 per Dth and a GCR Fixed High Load factor of $0.9074 per Dth.[18]

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 2015/2016 pipeline surcharge/credit for each path using actual pipeline capacity costs resulting in a Marketer surcharge of $34,124. After finalizing the 2014/2015 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 2015 through October

[17] *Id.* at 3-4.
[18] *Id.* at 5-6.

2016 with the actual surcharge for the 2014/2015 period which resulted in a $3,287 balance for that period. She identified a net surcharge to Marketers of $37,411 for the two-year period that would be credited to firm sales customers' fixed charges and included in the 2015-2016 pipeline surcharge/credits set forth by Ms. Arangio.[19] She stated that the monthly design sales forecast was calculated using a monthly specific heat factor.[20]

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 2016 through October 2017 period to be $88,605,517. She divided that number by the projected period throughput of 25,929,986 Dths to reach a Variable Cost factor of $3.4171 per Dth.[21] She asserted that an estimated deferred balance under-collection of $1,621,668 at October 31, 2016 was incorporated into the GCR rate as well as the projected deferred gas cost balances for the November 2016 through October 2017 period.[22]

Ms. Leary explained that the discrepancy in the monthly balances between June 2015 and November 2015 as set forth in her attachment and the deferred reports filed in Docket Nos. 4520 and 4576 was because the quarterly Natural Gas Portfolio Management Plan (NGPMP) credits had been restated. She presented a proposed FT-2 marketer demand rate of $8.0484 per Maximum Daily Quantity (MDQ) in Dth/month

[19] *Id.* at 6-7.
[20] *Id.* at 8.
[21] Leary Direct at 8-9, Att. AEL-1.
[22] Leary Direct at 9, Att. AEL-1, AEL-3.

and the Storage and Peaking charge of $0.0680 per therm for FT-1 firm transportation customers returning to Transitional Sales Service. 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.[23]

Ms. Leary explained that the Company had experienced negative monthly sales for May 2015 and August 2015 and identified billing adjustments for the Extra Large High Load factor customer class and the booking of accruals and reversals for Default Transportation customer class as causing this negative volume.[24] Finally, she provided that an average residential heating customer using 846 therms per year would experience a decrease of $69.51, which when combined with the Distribution Adjustment Charge increase of $47.26, would result in an annual savings of $22.94, or 2.0% from the previous year's bills.[25]

Mr. Poe provided testimony to support the Company's natural gas requirements forecast used to estimate its 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.[26] After determining the retail forecast, Mr. Poe explained that it is adjusted for billing lag and unaccounted-for-gas to

[23] *Id.* at 9-12, Att. AEL-5, AEL-6.
[24] Leary Direct at 12-13.
[25] *Id.* at 14.
[26] Poe Direct at 3-4 (Sept. 1, 2016).

determine the wholesale forecast. Both the retail and wholesale forecasts are used by the Company for supply, engineering, and financial planning.[27]

Mr. Poe related that the current year's retail forecast of 39,347,340 MMBtu indicated a 1.4% decrease over the last year's total retail forecast, with total sales decreasing by 4.1% and Commercial/Industrial Transportation increasing by 4.4%.[28] He explained this decrease from last year's gas price forecast as a result of a higher gas price forecast, significantly lower oil price forecast, and a much higher gas-to-oil price ratio. Finally, Mr. Poe described how the weather is used in the Company's forecasts.[29]

Mr. McCauley discussed the results of the Gas Procurement Incentive Plan (GPIP)[30] for the period July 1, 2015 through June 30, 2106 and the results of the Natural Gas Portfolio Management Plan (NGPMP) for April 1, 2015 through March 31, 2016.[31] The GPIP incentive or penalty is determined by multiplying the total savings or cost by 10%. When discretionary purchases made at least eight months prior to the month of gas flow where the unit cost savings is greater than fifty cents per dekatherm or by 5% for any discretionary purchases made during the four months prior to the month of flow, the total savings is multiplied by 20%. The Company calculated a $167,963 incentive, which Mr. McCauley proposed be granted in full.[32]

Mr. McCauley described the NGPMP, which shifted management of the Company's gas portfolio from an external company to internally within National Grid.

[27] *Id.* at 4-5.
[28] *Id.* at 7-8.
[29] *Id.* at 10-12.
[30] 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.
[31] McCauley Direct at 2 (Sept. 1, 2016).
[32] *Id.* at 3-5.

He noted that the program produced a total of $15,113,164.50 in savings from April 2015 through March 2016, $12,290,531.60 of which customers would receive. Mr. McCauley noted that the Company does not include any revenue from Asset Management Agreements in the incentive and was not proposing any changes to the NGPMP incentive at the current time. The Company received 20% of the total of savings in excess of $1 million or $2,822,632.90 for the April 2015 through March 2016 period.[33]

II. National Grid's Request for an Additional Hedge

On September 30, 2016, National Grid filed a request for an additional hedge to the GPIP for the upcoming winter season. Mr. McCauley provided prefiled testimony to support the Company's request.[34] He related that the Company's proposal sought to hedge a portion of its market area purchase price risk.[35] The market areas are New York and New Jersey, where the Company purchases supplies to use Algonquin pipeline capacity and Columbia pipeline capacity.[36]

Mr. McCauley explained that the reason for adding such hedges to the Company's current Gas Purchasing Incentive Plan was to balance the benefit of mitigating price risk for market area purchases.[37] He stated that although the Company had added pipeline capacity to its portfolio that did not eliminate the continued need to hedge market area price risk.[38] He explained that warmer-than-normal weather, incremental capacity to the region, lower crude oil prices and higher New England forward gas prices which will encourage liquefied natural gas imports, and ISO-NE's winter reliability program will

[33] *Id.* at 5-7.
[34] McCauley Hedge Proposal (Sept.30, 2016).
[35] *Id.* at 2.
[36] *Id.* at 3.
[37] *Id.* at 4.
[38] *Id.*

minimize price risk. However, he stated that growth in demand, the retirement of nuclear plants, and increased gas-fired generation could increase pricing.[39] He identified the purchase locations that caused the greatest impact on actual costs, noting that the Northeast region experiences the greatest volatility.[40] He explained that because not all of the transportation capacity within its portfolio had access to purchase supplies in the producing regions, the Company has to purchase some supplies in the market area.[41]

Mr. McCauley addressed why market area prices were not initially hedged in the Gas Purchasing Incentive Plan (GPIP). He explained that market area purchases are usually the highest cost supplies and identified these as “swing” supplies that are needed on colder than normal and sometimes normal winter days. He stated that since market area supplies are not needed on all winter days, they are typically purchased one day in advance, when the temperature forecast is more certain.[42]

He noted that although the net result was a cost of $2,597,243 for the market area hedges during the 2015-2016 period, the Company was recommending hedging at receipt points similar to those hedged in the 2015-2016 winter season. The exception was the replacement of the Algonquin city gate with Ramapo purchases, a Tetco M3-based price.[43] He explained that the new AIM capacity had moved the forecasted purchases from Beverly to Ramapo. Specifically, the Company was proposing to hedge the maximum receipt point volumes of approximately 3,500 dt per day at Downington using the Transco Non-NY Zone 6 as a hedge location, approximately 3,600 dt per day at Eagle, approximately 3,900 dt per day at Lamberville, and approximately 9,000 dt per

[39] *Id.* at 5-6.
[40] *Id.*
[41] *Id.* at 6.
[42] *Id.* at 6-7.
[43] *Id.* at 8.

day at Ramapo using the Tetco M3 hedge location. He stated that the Company was recommending hedging these volumes for the months of January, February, and March.[44] Although the hedging might result in potentially higher costs, he noted, the risk mitigated was more than ten times greater than the cost of baseloading these supplies.[45] Should the AIM project not be in service by November 1, he provided that the Company would delay hedging 9,000 dt per day of supplies until the project was put in service.[46]

Mr. McCauley explained that the Company did not recommend additional hedging for Tennessee Zone 6 supplies. He contended that the Company's Rhode Island customers would have to experience extreme weather and price spikes at least once every one to three years in order for such a hedge to be beneficial. Additionally, because the load factor was low at the purchase locations and the risk to purchase was small during December 2016, Mr. McCauley represented that the Company had not recommend hedging for those months.[47]

Mr. McCauley also provided that National Grid was not asking to hedge market area supplies beyond March 2017. The goal of its filing was simply to protect against price increases during the winter season similar to those experienced during the 2013-2014 winter season. He expressed that the Company would perform another analysis subsequent to the 2016-2017 winter season.[48] If the Commission approved the request, he noted, the Company would execute hedge volumes prior to December 22, 2016.[49]

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[44] *Id.* at 9

[45] *Id.* at 9-10. "Baseloading" was defined by Mr. McCauley in his testimony at page 8 as the "purchase [of] a fixed volume of supply for delivery each and every day of the month regardless of the weather or customer demand."

[46] McCauley Hedge Proposal at 11.

[47] *Id.* at 11-12.

[48] McCauley Hedge Proposal at 12. The four purchase locations, Tetco M3, Transco Non-NY Zone 6, Algonquin, and TGP Zone 6 are identified at page 6 of Mr. McCauley's testimony.

[49] McCauley Hedge Proposal at 13.

Finally, Mr. McCauley explained that the total commodity price was comprised of two components: a producing region price component and a transportation price component. He noted that the Company's instant proposal was to hedge a portion of the transportation component. He pointed out that the market area basis hedges would be excluded from the GPIP incentive calculation.[50] Lastly, he noted that the recommended hedges would result in the gas costs proposed in the September 1, 2016 GCR filing increasing by approximately $1.5 million.[51]

III. <u>National Grid's Revised Testimony</u>

On October 3, 2016, National Grid filed Revised Direct Testimony of Ms. Leary to update her prior testimony. Although the majority of the Revised Testimony reiterated her previously filed Direct Testimony, Ms. Leary made several updates. She updated projected gas costs for the Company's firm sales customers to approximately $118.4 million and Working Capital Costs to $0.8 million for a total of $119.5 million in net costs necessary for the Company to collect.[52] Ms. Leary again related the calculation of the Fixed Cost component and proposed a GCR Fixed Low Load factor of $1.1412 per Dth and a GCR Fixed High Load factor of $0.9074 per Dth.[53]

In updating the Variable Cost component, Ms. Leary provided for Variable Costs for the November 2016 through October 2017 period of $90,077,675. She divided that number by the projected period throughput of 25,929,986 Dths to reach a Variable Cost factor of $3.4738 per Dth.[54] She presented a proposed FT-2 marketer demand rate of $8.0484 per Maximum Daily Quantity (MDQ) in Dth/month and updated the Storage and

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[50] *Id.* at 13-14.
[51] *Id.* at 14.
[52] Leary Revised Direct at 3-4 (Oct. 3, 2016).
[53] *Id.* at 5-6.
[54] Leary Revised Direct at 8-9, Att. AEL-1 Revised.

Peaking charge to $0.0680 per therm for FT-1 firm transportation customers returning to Transitional Sales Service. Finally, she provided that an average residential heating customer using 846 therms per year would experience a decrease of $64.61. Combined with the Distribution Adjustment Charge increase of $47.26 and a $.054 decrease in Gross Earnings Tax, that would result in an annual savings of $17.89, or 1.5% from the last year's bills.[55]

IV. Division of Public Utilities and Carriers October 7, 2017 Filing

To address National Grid's filing, the Division of Public Utilities and Carriers (Division) submitted the testimony of Bruce R. Oliver, its consultant. Mr. Oliver observed a reduction of approximately 14% in GCR charges from last year's approved levels. He noted that the Company's proposed charges were the lowest since it had acquired the gas utility operations of Southern Union.[56] He asserted that the Company's adjustments and credits obscured the fact that Fixed Supply Costs for 2016 had increased significantly. He suggested that the Company's long-range plan be subject to a formal process, since future fixed costs are related to current long-term planning decisions and fixed cost commitments that may not be in the best interest of ratepayers.[57] He noted that the Company's data assumptions and forecasting methods were cause for concern to the Division and should be refined. He asserted that the current time period allowed for review of the GCR filing did not allow sufficient time to create a well-developed record on forecasting and planning.[58] Finally, he expressed that the unresolved issues related to National Grid's proposal to allow Capacity Exempt customers to transfer to Capacity

[55] *Id.* at 14, Att. AEL-4 Revised.
[56] Oliver Direct at 2-3 (Oct. 7, 2016).
[57] *Id.* at 4-5.
[58] *Id.* at 6.

Assigned service could have a direct impact on capacity requirements and affect reliability for other customers. Because of this, any future changes should consider the adequacy of the Company's gas supply resources and the costs that the changes may have on other firm gas service customers.[59]

Mr. Oliver reiterated the Company's proposed GCR charges. He attributed the projected reductions in the Company's gas costs to: (1) lower overall market prices for natural gas, (2) a successful GPIP, and (3) a productive asset management incentive structure. He attributed the greater percentage reductions in proposed GCR charges to (1) an increase in the NGPMP benefit, (2) an increase in credits for deferred fixed cost over-recoveries, (3) a decrease in variable cost under-recoveries, and (4) a forecasted reduction in annual sales volumes.[60] He found the Company's calculations for the $167,963 GPIP incentive to be accurate and recommended approval.[61] He also found the calculation of the $2,822,632 NGPMP incentive to be accurate and recommended its approval. He noted that the ratepayer share of the benefit of $12,290,532 was the largest benefit to date.[62]

Mr. Oliver reviewed Mr. McCauley's testimony regarding National Grid's market area hedging proposals which modified its current hedging plan by adjusting receipt points and months. He noted that the proposed hedges were focused on receipt points that were baseloaded, since those that are not tend to have a greater risk that their costs will exceed realized benefits under than warmer than normal weather conditions. He

[59] *Id.* at 7-8.
[60] *Id.* at 8-11.
[61] *Id.* at 11-12.
[62] *Id.* at 14-15.

expressed satisfaction with and supported the proposal, noting its likelihood to produce positive benefits and reduce the impacts of extreme cold weather on gas costs.[63]

Mr. Oliver reviewed the Company's GCR Reconciliation calculations and found no errors.[64] Of the five implemented and proposed changes to National Grid's gas supply portfolio, Mr. Oliver noted that the scheduled start-up of the AIM Project, the Texas Eastern Supply Restriction, and removal of the Cumberland LNG Tank from service warranted further review. He asserted that the AIM Project represented 22% of the increase in Supply Fixed costs that the Company was projecting for the coming GCR year and that National Grid had not provided an estimate of the impact of the delay on its estimated gas costs.[65] He also expressed that the restriction on the Texas Eastern System had limited the Company's access to its least expensive gas supply and noted that should this restriction continue beyond November 1, National Grid would have to purchase gas at more expensive locations. Although the Company had issued an RFP to secure an option to call at a location downstream of facilities subject to the restriction, Mr. Oliver alleged that it had not included the cost of these options in its GCR costs.[66] He also expressed concern that it was unlikely National Grid would be able to avoid the costs of the options even if the restriction was lifted. He alleged that it did not appear that the options were pursued under the GPIP or that contracting process underwent the same scrutiny was applied to a GPIP hedge. He recommended that these costs not be allowed unless a rigorous assessment was performed.[67] Mr. Oliver found National Grid's strategies to replace the Cumberland Tank LNG capacity to be unreasonable and asserted

[63] *Id.* at 17-19.
[64] *Id.* at 20-21.
[65] *Id.* at 21-23.
[66] *Id.* at 24-25.
[67] *Id.* at 26-27.

that the information provided by the Company did not support the level of fixed costs. Further, he noted that there were no adjustments made to LNG operation and maintenance costs that address the removal of the tank from service.[68]

Mr. Oliver provided that forecasts were necessary for the Company to develop its GCR filings. He noted that near-term forecasts affect both the magnitude of projected gas costs and the estimates of numbers of therms over which these costs are to be recovered. Additionally, he stated that long-term forecasts guide the Company's financial commitment decisions and were the major drivers of fixed costs.[69] He stressed that forecasting errors could result in the Company incurring costs for loads that have little or no likelihood of occurrence and are greater than average costs. Also, there was no reconciling mechanism to correct errors in long-term forecasts.[70] Mr. Oliver identified a number of errors and inconsistencies that he found in National Grid's forecasts.[71] He identified specific long-term planning issues and maintained that the Commission should act to ensure that the Company's plans to acquire or construct LNG liquefaction capacity were in the best interest of its customers. To do this, he asserted, the Commission should require the Company to provide evidence of long-term supply commitments for all or substantially all of the facility's projected input requirements.[72] He also expressed concern that some of the Company's planning criteria over-stated the amount of capacity required to provide reliable service. That this could result in an economic burden on ratepayers. He suggested bifurcating the GCR process and having a structured process whereby the Commission would separately review any request for recovery of a new

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[68] *Id.* at 28-29.
[69] *Id.* at 30-31.
[70] *Id.* at 31-32.
[71] *Id.* at 32-40.
[72] *Id.* at 41-42.

fixed Supply or Storage costs. He asserted that this would provide for a thorough vetting and development of the record.[73]

V. National Grid's Reply Comments

In response to Mr. Oliver's direct testimony, National Grid filed the Rebuttal Testimony of Ms. Arangio, Ms. Leary, and Mr. Poe. Ms. Arangio addressed Mr. Oliver's testimony regarding (1) his suggestion for a more rigorous review of the long-term planning process, (2) the AIM Project capacity, (3) the Texas Eastern Supply Restriction, and (4) the Cumberland LNG facility. Ms. Arangio represented that National Grid supported Mr. Oliver's call for greater Commission oversight of the Company's planning, forecasting, and long-term financial commitments for gas supply.[74] She recommended that it be a two-step approach. The Commission should first accept the Company's forecasting methodology and forecast and then approve future gas supply precedent agreements of greater than one year. She maintained that this approach would achieve the same objectives as Mr. Oliver's suggested bi-furcated approach.[75]

Ms. Arangio addressed the references made by Mr. Oliver regarding Capacity Exempt customers being allowed to transfer to Capacity Assigned service. She stated that before the Company could do that, it needed to resolve the outstanding forecasting and planning issues in conjunction with the proposal.[76] She asserted that the capacity from the AIM Project was supported by both price and non-price factors.[77] Ms. Arangio

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[73] *Id.* at 42-44.
[74] Arangio Rebuttal at 1-3 (Oct. 18, 2016).
[75] *Id.* at 4-5.
[76] *Id.* at 5.
[77] *Id.* at 6-8.

defended the Company's decision to secure an option to call and pointed out that because the price for gas under this contract is not fixed it does not fall within the GPIP.[78]

With regard to the Company's decision to take the Cumberland LNG tank out of service, Ms. Arangio stressed that safety was National Grid's top priority. She noted that without replacement supply available on the existing Tennessee city gate stations and/or portable LNG, the Company would not be able to meet customer requirements under design weather conditions.[79] She provided that the plans to replace the Cumberland LNG tank capacity were reasonable in light of actual sendout volumes provided by the tank over the prior three winters. The plans were also reasonable because they provided the only practical solution allowing National Grid to meet forecasted customer requirements and support the Company's obligation to provide lease-cost reliable service.[80]

Ms. Leary's rebuttal testimony addressed National Grid's LNG operation and maintenance costs and the 2016-17 GCR forecasting. She disputed Mr. Oliver's assertion that these costs were not adjusted to reflect the Cumberland LNG tank being taken out of service. She provided that supply-related operation and maintenance costs were set in the Company's general rate case and fixed until the next rate case.[81] Ms. Leary also explained how the Company developed its design forecast and calculated heating factors neither of which were used to allocate fixed gas costs.[82]

Mr. Poe's Rebuttal Testimony described the Company's forecasting methodology. It also addressed Mr. Oliver's allegations that certain Company projections were

[78] *Id.* at 8-12.
[79] *Id.* at 12-13.
[80] *Id.* at 16.
[81] Leary Rebuttal at 1-2 (Oct. 18, 2016).
[82] *Id.* at 4-5.

erroneous and some of its estimates were irrational and inconsistent.[83] He also discussed the gas supply planning process. Finally, Mr. Poe stated that the Commission should accept the Company's forecasts which would allow for appropriate cost recovery and for the Company to to serve its customers in a safe, reliable, and least-cost fashion.[84]

HEARING

At the hearing on October 21, 2016, National Grid's Motions for Protective Treatment[85] were granted and, after ensuring no objection, all exhibits were marked as full exhibits.[86] Prior to presentation of the Company's witnesses, Mr. Robert Humm, counsel for National Grid, represented that the Company and the Division had agreed to remove forecasting and planning issues from future GCR filings, to work to develop a process regarding planning criteria and long-range planning, and to require National Grid to obtain approval for long-term agreements for additional gas capacity. Mr. Humm represented that details of a report memorializing the agreement would be filed with the Commission by January 16, 2017.[87]

Mr. Humm presented Ms. Leary, Ms. Arangio, Mr. Poe, and Mr. McCauley as a panel. All of the witnesses adopted their prefiled testimony and sponsored data request responses.[88] Ms. Arangio testified that National Grid was agreeable to having the Commission approve the Company's gas capacity contracts of longer than one year.[89] She explained that although the fixed cost component of the AIM project was higher than the fixed costs for the hubline and east to west contracts, its variable costs were much

[83] Poe Rebuttal at 2-27 (Oct. 18, 2016).
[84] *Id.* at 27-30.
[85] Hr'g Tr. at 6.
[86] *Id.* at 5.
[87] *Id.* at 7-8.
[88] *Id.* at 13-25.
[89] *Id.* at 38.

less. She noted that when the send-out model was applied to the AIM contract, it provides a lower cost option for ratepayers. It would provide access to least cost supplies that could be optimized year round as opposed to just in the winter when variable costs are much higher.[90]

Mr. McCauley explained the difference between the GPIP and the NGPMP, and associated incentives, and the Company's market area hedging proposal.[91] Mr. Poe discussed the increase in the Company's forecast between the current year and the prior year, noting it was based on what the Company observed. He explained how National Grid was unable to tell if a customer self-converts by switching from an oil to a gas furnace. He provided that the increase in the forecast was the result of self-conversions, customers that the Company migrated from the non-heating to the heating class, higher usage by existing customers, and the incredibly warm prior winter.[92]

Ms. Arangio explained the process that Massachusetts engaged in to approve National Grid's long-range gas plan, which is filed every two years, and capacity contracts.[93] She noted that the Massachusetts review considered whether the contract complemented the Company's asset portfolio and was a least cost alternative.[94] Mr. Poe was questioned about the difference in design days for Rhode Island and Massachusetts and asked to explain the discrepancy in the ratios used for frequency of occurrences between the two states. He explained that heating degree days in Massachusetts were measured differently than in Rhode Island because Massachusetts incorporated a wind component. He explained that in Rhode Island, National Grid used sixty-eight heating

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[90] *Id.* at 39-41.
[91] *Id.* at 48-50.
[92] *Id.* at 59-62, 64, 71-73.
[93] *Id.* at 74-79.
[94] Id. at 80-82.

degree days. He noted that the difference in frequency occurrence between the two states was only a degree day or two at most.[95]

The Division presented Mr. Oliver who concurred with the statements of Mr. Humm regarding the agreement between the Division and the Company as to forecasting, long-range planning, and the manner in which capacity contracts would be considered by the Commission. He testified that all of these issues were important in determining the system's fixed costs. He noted that although gas costs were presently low, he saw signs that those costs might increase at the same time the Company would incur more capacity costs.[96]

Mr. Oliver noted that both the NGPMP and the GPIP were working well and supported continuation of the NGPMP.[97] He suggested that the Company conduct further review when it experienced large differences in the forecast or unusual situations and that it evaluate its requirements and consider the impact the capacity exempt load had on the requirements.[98] Mr. Oliver testified that the forecast should be Rhode Island specific, as opposed to some broader forecast, because of unique issues such as transferring rate classes that the forecast is sensitive to.[99]

Although not ready to commit to a time period, Mr. Oliver maintained that the Commission should approve the Company's long-term gas contracts. He provided that these contracts form the foundation of future gas costs.[100] He asserted that review time for those contracts should be long enough for parties to examine and analyze the

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[95] *Id.* at 86-89.
[96] *Id.* at 101-102.
[97] *Id.* at 106, 111.
[98] *Id.* at 107-109.
[99] *Id.* at 117.
[100] *Id.* at 118-119, 134.

forecasts, economic analyses of the projects, and alternative to those projects.[101] Finally, Mr. Oliver represented that the Division recommended approval of the proposed BTU factor.[102]

COMMISSION FINDINGS

Immediately following the hearing, the Commission approved a High Load GCR Charge of $0.4525 per therm for Residential Non-Heating, Large High Load, and Extra Large High Load classes. It approved a Low Load GCR Charge of $0.4766 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 $8.0484 per dekatherm per month, a Storage and peaking charge for FT-1 Transportation customers of $0.6802 per Dekatherm, and a weighted average system capacity charge of $0.3766 per dekatherm of capacity for usage on and after November 1, 2016.

The Commission found the Company's request for the $167,963 incentive on its GPIP and the NGPMP incentive of $2,822,632.90 to be fair and reasonable and approved the same. It also approved the Company's request to continue the NGPMP for another year. As previously held, the Company was not allowed to earn an incentive on its third-party asset management agreements. The Commission approved the Company's hedge proposal filed on September 30, 2016. Finally, the PUC approved the BTU Conversion Factor of 1.029. The Commission's approval was based on the representations of the Company and the Division, that they would enter into an agreement regarding forecasting, long-range planning, and the manner in which the Commission will review

[101] *Id.* at 122-123.
[102] *Id.* at 145.

and approve the Company's capacity contracts. 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

(22779) ORDERED:

1. The Gas Cost Recovery factors of:
   a. $0.4525 per therm for Residential Non-Heating customers, Large High Load, and Extra Large High Load Factor customers and
   b. $0.4766 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, 2016.
2. A Weighted Average System Capacity Charge of $0.3766 per dekatherm is approved for usage on and after November 1, 2016.
3. The Gas Marketer Transportation factors of:
   a. $8.0484 per dekatherm for the FT-2 Firm Transportation Marketer Gas Charge and
   b. $0.6802 per dekatherm for a Storage and Peaking Charge

   are approved for usage on and after November 1, 2016.
4. The incentive of $2,822,632.90 for the Natural Gas Portfolio Management Plan is approved.
5. The incentive of $167,963 for the Gas Procurement Incentive Plan is approved.

6. The Company shall file its Annual Gas Cost Recovery Reconciliation by July 1 of each year.
7. The BTU factor of 1.029 is approved.
8. National Grid and the Division shall submit a report to the Commission by January 16, 2017 detailing how the Company will prepare and provide forecasts, long-term planning, and the Company's capacity contracts and the process for Commission review.
9. National Grid shall provide electronic versions of all spreadsheets at the time of its initial filing.
10. National Grid shall comply with the reporting requirements and all other findings and directives contained in this Report and Order.

EFFECTIVE NOVEMBER 1, 2016 IN WARWICK, RHODE ISLAND PURSUANT TO A BENCH DECISION ON OCTOBER 21, 2016. WRITTEN ORDER ISSUED APRIL 27, 2017.

PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

Herbert F. DeSimone, Jr., Commissioner

Marion S. Gold, Commissioner*

*Commissioner Gold did not participate in this 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.