STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: NARRAGANSETT ELECTRIC :
d/b/a NATIONAL GRID :
GAS COST RECOVERY CHARGE : DOCKET NO. 4436

REPORT AND ORDER

I. NATIONAL GRID'S SEPTEMBER 3, 2013 FILING

On September 3, 2013, National Grid (National Grid or Company) submitted its Gas Cost Recovery (GCR) filing with 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. This filing proposed to decrease the rates approved by the PUC in Docket No. 4346 for the period November 1, 2013 through October 31, 2014. The proposed rates result in an annual decrease of approximately $8.00 for a typical residential heating customer using the equivalency of 846 therms per year.

In support of its filing, National Grid submitted the pre-filed 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.; 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 for the estimated gas costs, assignment of pipeline capacity to

[1] Prefiled testimony is available at the Commission offices located at 89 Jefferson Boulevard, Warwick, Rhode Island or at www.ripuc.org/eventsactions/4436page.html.

marketers, other issues relating to the Company's proposed factors, and a summary of the National Grid and Algonquin Gas Transmission Company Precedent Agreement (PA) for interstate pipeline capacity delivered to the state as part of the Algonquin Incremental Market Expansion Project (AIM Project). 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 15, 2013 and the difference between the futures contract purchases under the Gas Procurement Incentive Plan as of July 2013 and the July 15, 2013 NYMEX strip. The factors also reflect storage and inventory costs as of July 31, 2013 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 this year's NYMEX pricing is higher than it was last year.[2]

Ms. Arangio described how the Company uses a SENDOUT model to calculate projected gas costs. To minimize yearly supply cost, pricing, contract, and storage information are used to determine the dispatch of supplies. 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 expense incurred to transport and store the gas, and inventory commodity costs. Attached to her testimony, Ms. Arangio provided supporting detail for the gas costs. She described how the Company calculates the delivered cost for a particular gas supply as beginning with the NYMEX

[2] Arangio Direct at 1-6 Sept. 3, 2013.

price, then being adjusted for basis differential and to reflect fuel retention, and finally being added with the cost of transportation on the pipeline.[3]

Regarding marketer capacity assignment, Ms. Arangio represented that the Company has made 32,758 Decatherms (Dth) per day of capacity on six different pipeline paths available to marketers. 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 indicated that to calculate the non-gas variable costs, commodity gas costs are subtracted from the total variable costs. As an example, she described the calculation using one particular path. She added a fixed unit cost of $0.7414 to the non-gas variable unit cost of $0.4249 to derive the $1.1663 cost of the path to be paid directly to the pipeline by marketers. Because this cost exceeds the $0.9383 system average, marketers electing that specific path would receive a $0.2280 per Dth credit for the difference between the direct cost and the system average cost.[4]

Ms. Arangio next described the Company's various contracts and its plans to supply the East-West Capacity for 2013-2014. She also provided that National Grid entered into a contract to address the significant decline in sources traditionally available at the interconnect in Beverly, Massachusetts and to replace liquid natural gas (LNG) volumes that are uncertain in the future. National Grid entered into two arrangements for liquid service for the 2013 off peak refill season and is in discussions with other companies for capacities to meet remaining refill requirements. Ms. Arangio described the changes to the global and domestic LNG markets currently affecting National Grid. She explained that National Grid has only two pipelines that deliver into the Company's

[3] *Id.* at 6-8, Attachment EDA-2.
[4] *Id.* at 8-9, Attachment EDA-4.

distribution system and that both pipelines are fully subscribed, requiring National Grid to rely on LNG to meet system pressure requirements during peak demand periods. Historically, to meet its full obligations to supply gas, LNG has provided 38% of gas needed to satisfy the Company's peak day requirements. She noted that LNG imports are at their lowest level in thirteen years and that higher global prices are diverting LNG cargoes away from the United States. Despite the substantial increase in domestic production of natural gas, National Grid is unable to realize the full benefit of lower priced gas because of its inability to transport that gas due to insufficient pipeline capacity.[5]

Ms. Arangio described how the Company is responding to the changes in the gas supply landscape in order to ensure safe and reliable service to its existing customers and opportunity for growth for new customers. She explained how the Company is participating in the AIM Project which will allow it to access Algonquin's interconnection in Ramapo, NJ and to abundant inexpensive gas, as well as access to supplies available at the interconnection with the Iroquois Gas Transmission at Brookfield, Connecticut. Ms. Arangio also noted that National Grid is considering whether to participate in the Tennessee Northeast Expansion Project which consists of upgrading the existing line to alleviate supply concerns at Dracut.[6]

Ann 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 which resulted in total Fixed Costs of $31,530,147 to be allocated to and collected from ratepayers based on their

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[5] *Id.* at 11-19.
[6] *Id.* at 19-21.

proportional design-winter use requirements. She identified expected throughput of 1,301,599 Dths or 4.07 of the total throughput for High Load classes for a factor of $0.9861 per Dth and 24,718,392 Dths or 95.93 percent of the total throughput for the Low Load classes for a factor of $1.2236 per Dth.[7]

Ms. Leary noted that previously the Company agreed to provide an annual reconciliation of Marketer fixed costs and described the calculation of the Marketer Fixed Cost Reconciliation Balance which she stated has been updated and revised to better reflect the difference between projected and actual fixed costs paid by marketers during the 2011-2012 and 2012-2013 GCR periods. She identified a net surcharge to Marketers of $8,205 that would be credited to firm sales customers fixed charges and included in the 2013-2014 pipeline surcharge/credits set forth by Ms. Arangio. She stated that the design winter calculation was developed using calendar month degree days,[8] consistent with the Commission's finding in Docket No. 4097.[9]

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 O&M, working capital, inventory finance costs, pipeline refunds, and deferred cost balances. She calculated variable costs for the November 2013 through October 2014 period to be $135,102,948 which she divided by the projected period throughput of 26,019,992 Dths to calculate a Variable Cost factor of $5.1922 per Dth. She asserted that an estimated deferred balance under-collection of $11,859,371 is incorporated into the

[7] Leary Direct at 5-6, Attachment AEL-1, Sept. 3, 2012.
[8] In Docket No. 4097, Order No. 19832. the Commission accepted the parties agreed to change in methodology for determining forecasted design-winter requirements from billing cycle design days to calendar month design-degree days.
[9] Leary Direct at 6-7, Attachment AEL-7, Sept. 3, 2013.

GCR rate as well as the projected deferred gas cost balances for the November 2013 through October 2014 period.[10]

Ms. Leary noted that off-system capacity credits that were inadvertently allocated to Supply Fixed Costs were reallocated to Supply Variable Costs. She presented a proposed FT-2 marketer demand rate of $9.7373[11] per Dth/month and the 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. Lastly, Ms. Leary identified an approximate $8.00 annual reduction to a residential customer using 846 therms per year resulting from the proposed rates.[12]

Mr. McCauley discussed the results of the Gas Procurement Incentive Plan[13] for the period July 1, 2012 through June 30, 2103 and the results of the Natural Gas Portfolio Management Plan (NGPMP) for April 1, 2012 through March 31, 2013 and recommended that the NGPMP continue after March 31, 2014. The Gas Procurement Incentive Plan incentive or penalty is determined by multiplying the total savings or cost by 10% except that the total savings is multiplied by 20% for those discretionary purchases made at least eight months prior to the month of gas flow where the unit cost savings is greater than 50 cents per dekatherm or by 5% for any discretionary purchases

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[10] *Id.* at 8, Attachments AEL-1, AEL-3.

[11] Ms. Leary corrected this figure at hearing noting that the value per MDQ should be $9.7353 per MDQ in Dth/month.

[12] Leary Direct at 8-11, Attachments AEL-2, AEL-4, AEL-5, AEL-6, Sept. 3, 2012.

[13] 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 24-month horizon and that these purchases are made 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.

made during the four months prior to the month of flow. The Company calculated a $453,345 incentive that Mr. McCauley proposed be granted in full.[14]

Mr. McCauley described the NGPMP which shifted management of the Company's gas portfolio from an external company to internally within National Grid. He opined that internal management is superior to the previous external management arrangement, because it reduces the potential for performance failure by an external manager and because the Company is appropriately incentivized to maximize savings in excess of that of the third party manager. Noting that the NGPMP is currently in its third year,[15] Mr. McCauley said it has saved the Company $8,412,856. He noted that the program passed $6,930,285 of those savings on to customers, while the Company received 20% of the total of savings in excess of $1 million or $1,482,571 for the April 2012 through March 2013 period. Mr. McCauley noted that the Company and the Division reviewed the terms of the NGPMP and concluded that continuation of the Plan was in the best interest of ratepayers.[16]

Regarding the portion of the incentive applicable to the Company's asset management agreements, Mr. McCauley explained that during the period that the NGPMP has been in existence, the Company has released a small number of transportation contracts as stand-alone asset management agreements. He stated that in an asset management agreement, even though the Company releases its asset to a third party, it retains the right to call on the supply when needed. He explained that the

[14]McCauley Direct at 1-5, Attachments SAM-1, SAM-1a, SAM-2, Sept. 3, 2013.
[15] The Commission approved the NGPMP in Docket No. 4038, Order No. 19627 on March 31, 2009.
[16] McCauley Direct at 5-8, Attachment SAM-3, Sept. 3, 2013. In proposing its NGPMP, National Grid represented that the benefits incurred with the NGPMP would include the reduction of risk of performance failure by a third party such as financial distress or bankruptcy as well as having a staff with expertise, market intelligence and contractual relationships to best meet the needs of customers. National Grid. Docket No. 4038, Exhibit 1, Natural Gas Portfolio Management Plan, Direct Testimony of Stephen A. McCauley filed Feb. 24, 2009 at 6.

NGPMP was intended to apply to a total portfolio outsourcing, not individual asset paths. He further explained why the Division might interpret the Company's outsourcing of a single transportation contract to be inconsistent with the Company's representations that the management activities would all be done in-house. Nevertheless, he contended, the incentive should be the same for all portfolio management methods under the NGPMP. The best management approach is to have a combination of internal management, capacity releases, and asset management agreements. He recommended that the NGPMP be extended for an additional four years with a review by the Company and the Division after March 2017.[17]

II. DIVISION OF PUBLIC UTILITIES AND CARRIERS

The Division of Public Utilities and Carriers ("Division") submitted a memorandum by Bruce R. Oliver, its consultant, to address National Grid's filing. He noted his review was subject to difficult time constraints.[18] He explained that while the Company's variable gas supply and storage costs have declined over the past year, its fixed supply and storage costs have risen significantly due to a large change in the reconciliation balance and an increase in NGPMP credits. Mr. Oliver identified a $16.1 million under-collection in the variable cost balance as the primary reason for the upward adjustments required to the variable cost balance. He was satisfied with the mathematical accuracy of the computations used to calculate the proposed GCR charge.[19]

Mr. Oliver explained that the Company's data revealed a $6.8 million upward adjustment to commodity costs made in May of 2013. He noted that it was the second

[17] *Id.* at 8-9, Attachment SAM-3.
[18] The initial filing was made on September 3, 2013. The Division's response was due shortly thereafter on October 8, 2013.
[19] Oliver Memorandum at 1-2, Oct. 8, 2013.

time in two years that the Company has made such a revision. Additionally, he noted that recent monthly deferred balance reports reflected a large negative sales volume for the Extra Large Low Load Factor and High Load Factor sales service classifications, requiring further explanation. He observed a large increase in forecasted throughput, an unexpectedly large increase in projected sales to residential non-heating customers, and very large increases in projected annual sales and throughput and design winter sales for Large High Load Factor, Extra Large High Load Factor and Extra Large Low Load Factor rate classifications. Because of the projections of increased winter growth for the Residential Non-Heating class, Mr. Oliver suggested that the Company monitor this situation. Those customers might fail to meet the threshold of having at least 31% of their annual gas use in the months of May through October and as a result may no longer qualify as high load factor customers. Additionally, he recommended that the Commission require the Company to investigate the reasons for the change in these customers' usage characteristics.[20]

Mr. Oliver observed that National Grid's Design Day Peak for the 2013-2014 winter is higher than what was forecasted in the Company's Long-Range Gas Supply Plan and opined that additional peak supply may be necessary sooner than expected. He proposed that a new five-year Gas Supply Plan be filed every three years as he had suggested in last year's docket. His review of the Company's calculation of its Gas Procurement Incentive Plan incentive revealed nothing to raise concern with the accuracy of the calculation. While he did not object to extending the NGPMP, he did not agree with Mr. McCauley's suggestion that the Company be given discretion to utilize internal asset management along with capacity release arrangements and external asset

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[20] *Id.* at 2-3.

management through asset management agreements with third parties as it deems appropriate. He explained that when National Grid initiated the NGPMP, it represented that internal asset management would provide greater benefits to the Company's firm service customers. While the Division has no objection to some small portion of Company's portfolio being managed by third parties, he related that increasing the asset management agreement portion of the portfolio weakens the rationale for the level of National Grid's incentive.[21]

Subsequently, the Division filed a revised memorandum by Bruce Oliver. The revised memorandum included an attachment detailing changes in projected costs by GCR cost component, omitted from the original memorandum because of tight time constraints. Mr. Oliver noted that overall projected gas costs have declined by approximately $3.5 million or 2.1% from the Company's projections last year, with fixed costs increasing and variable costs decreasing. Additionally, a number of cost adjustments and reconciliations were added to the Company's projections, increasing the overall costs by $5.1 million or 3.2%. Those increased costs caused the fixed cost component or the recovery requirement to decline from last year's filing and the variable cost recovery requirement to be greater than last year. Mr. Oliver identified the major drivers of the swings in the total fixed and total variable costs after adjustments and reconciliations as resulting from large changes in the deferred balances of those costs. He related that last year's over-recovery in deferred fixed costs of $10.7 million is an under-recovery of $4.2 million this year, and last year's $10.2 million over-recovery of variable costs as a $16.1 million under-recovery this year. He related that the Company's

[21] *Id.* at 4-5.

calculations appear accurate and consistent with established procedures for computing those charges.[22]

IV. NATIONAL GRID OCTOBER 16, 2013 REBUTTAL

National Grid filed the joint rebuttal testimony from Ms. Leary, Ms. Arangio, and Mr. McCauley. The rebuttal testimony explained that the increase in normal-weather sales and throughput forecast after years of low or negative growth that Mr. Oliver had identified was the result of the economy, which the Company contended should be seen as a sign of gas demand returning to where it was prior to 2006. The rebuttal also discussed the increase in projected gas sales to the Residential Non-Heating customers. It noted the demand of that class shows seasonal characteristics and is actually predicted to decline slowly from what the Company observed in 2012-2013.[23]

Responding to Mr. Oliver's assertion that the increase in the design peak day requirements suggested that the Company should file a Long Range Gas Supply Plan every three years rather than every five years, the Company provided that it plans on filing its next Long Range Gas Supply Plan in March of 2014. Additionally, National Grid agreed to keep the Commission informed of any changes in gas supply requirements and to pursue the least-cost reliable options to provide natural gas to its customers. The rebuttal also addressed and attempted to justify the $46,325 of incentives attributable to asset management agreements in the NGPMP.[24]

The Company agreed to monitor the usage and load factor for Residential Non-Heating customers to ensure appropriate rate treatment as Mr. Oliver suggested. The rebuttal noted that, although National Grid made upward changes to its deferred gas costs

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[22] Oliver Revised Memorandum at 1-2, Oct. 10, 2013.
[23] National Grid Rebuttal at 1-3 Oct. 16, 2013.
[24] *Id.* at 3-7.

that include adjustments to costs that were subject to prior gas cost reconciliation filings for the second time in two years, the prior period adjustments ultimately led to an overall net decrease in the total deferred gas cost balance ending March 2012. Lastly, the rebuttal explained that the Company experienced negative sales volume for the Extra Large Low Load factor rate class in May 2013 because of adjustments associated with two prior months' billings.[25]

V. HEARING

At the hearing on October 17, 2013, the Chairperson granted National Grid's Motion for Protective Treatment and after ensuring no objection, all exhibits were marked as full exhibits. National Grid presented Ms. Arangio, Ms. Leary and Mr. McCauley as a panel. Ms. Arangio stated that the Company was seeking $155 million in projected gas costs, prior to adjustments. She reiterated the two components of gas costs: fixed costs and variable costs. She identified the Company's design day sendout to be approximately 328,500 decatherms and noted that National Grid's Rhode Island customers are served by two pipelines, the Algonquin Gas Pipeline and the Tennessee Gas Pipeline.[26]

Ms. Leary testified that she concurred with the numbers and analysis provided by Mr. Oliver including his increase in projected gas costs by approximately $5.1 million as compared to last year's projected costs, which she explained was the result of an increase in throughput. Mr. McCauley explained how the $46,325 incentive amount associated with the asset management agreements was not included in the current incentive amount before the Commission, and it would be part of next year's GCR filing. He reiterated the

[25] *Id.* at 7-9.
[26] Hr'g Tr. 3-11, Oct. 17, 2013.

three issues the Company was seeking approval of as: (1) the continuation of the NGPMP for an additional four years with a review of that plan after three years, (2) the $453,345 Gas Procurement Incentive Plan incentive for the period July 2012 through June 2013, and (3) the $1,482,571 incentive on the NGPMP for the period April 2012 through March 2013.[27]

In response to cross-examination, Ms. Arangio indicated that the Company will file a Long Range Gas Supply Plan every two years. Upon further questioning about the incentive associated with the asset management agreements, Mr. McCauley stated that the $46,325 figure was 20% of the total asset management fees. He justified the Company's incentive for the asset management agreements by noting that an asset management agreement is another tool used by National Grid to manage bundled sales, such that it is essentially internal management. When asked if the Company was receiving an incentive for activities that it was not performing, Mr. McCauley asserted the development of an asset management deal is a critical part of the fee. He related that asset management agreements comprise only 4.6% of the Company's actual asset management, and that the Company has no intention at this time of expanding the number of third party asset management agreements. Mr. McCauley testified that the use of third-party asset management did not increase risk because of the small percentage of total capacity provided for by these agreements. Additionally, because the Company buys and sells gas from many parties, it further diversifies risk.[28]

Ms. Arangio offered that National Grid issued an RFP for the asset management agreements and selected the best bids received. When discussing supply, Ms. Arangio

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[27] *Id.* at 11-16.
[28] *Id.* at 16-32.

related that the Company's design day and strategic approach to ensuring adequate supply are to make sure the Company has adequate space in the pipe to meet its design day requirements. She noted that the design day in Rhode Island is growing either because more people are using gas or the people currently using gas are using more of it.[29]

The Division presented Mr. Oliver. He reiterated the concerns raised in his prefiled testimony, specifically the changes in the costs at which the Company is buying capacity and commodity and the adjustments made to those costs to come up with a GCR rate. He reiterated his prior testimony regarding the changes in the fixed-cost adjustments noting that a big driver of the change was the change in the deferred cost recovery amount. Because the swing of over-recovery and under-recovery for this year and the previous year were in opposite directions for fixed and variable costs, Mr. Oliver noted that they substantially offset each other indicating that the Company is doing a good job with managing its costs.[30]

When questioned about the Company's third-party asset management agreements, Mr. Oliver related that some small portion of the overall asset management being performed by a third party does not cause him concern. He contended that as long as the asset management agreements comprised no more than 20% of the Company's portfolio, an incentive earned was not objectionable. Regarding the Company's forecasts, Mr. Oliver expressed concern that load projections for the coming winter

[29] *Id.* at 36-54.
[30] *Id.* at 56-61.

increased noticeably from the previous couple of years. He opined that perhaps old contracts should be maintained or additional capacity should be added quickly.[31]

Mr. Oliver also discussed LNG and its importance should design-day demands grow. He cautioned that LNG is to be used for design days and should not be used for economic purposes, unless it will be refilled. When discussing the pipeline constraints, Mr. Oliver related that there will always be a question of how much gas will exist at the supply sources and how much throughput will be required at the other end. He noted that there must be a reliable response to both of these questions in order to initiate an expansion project. He stressed the necessity for generators to make commitments, as it is unfair for gas utility ratepayers to have to pay for extra capacity to ensure that merchant generators have enough supply. When questioned about the Company's incentive on the Gas Procurement Incentive Plan, Mr. Oliver testified that he believed the incentive to be reasonable.[32]

VI. COMMISSION FINDINGS

At an open meeting on October 25, 2013, the Commission discussed the proposed GCR rate. The PUC approved a High Load GCR Charge of $0.6381 per therm for Residential Non-Heating, Large High Load, and Extra Large High Load classes. It approved a Low Load GCR Charge of $0.6626 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 Demand charge of $9.7353 per dekatherm per month and a weighted average upstream pipeline transportation cost of $0.9383 per dekatherm of capacity.

[31] *Id.* at 62-71.
[32] *Id.* at 72-83.

The PUC accepted the Company's proposal that it continue to perform in-house many of the asset management activities previously outsourced to third parties. In terms of incentives earned by the Company in its asset management performance, the Commission is satisfied that the Company is entitled to an incentive related only to those functions performed internally. Where the Company has chosen to delegate asset management to third parties, there is no compelling reason for the Company to be awarded an incentive. This decision properly balances ratepayer and Company interests, in that it continues to incentivize the Company's direct involvement with decisions to maximize the value of the assets under its management, which is the primary feature of the incentive based regulatory mechanism. As there is no requirement of a time period for which to extend the NGPMP and because of the dynamic nature of the market, the Commission found that approving the NGPMP without establishing a time frame will allow for further examination of the Plan, its benefits, and whether or not an incentive is appropriate.

Additionally, the Commission found the Company's request for the $453,345 incentive on its Gas Procurement Incentive Plan to be reasonable and approved the same. The PUC believes that the current volatility of the market dictates the need for the Company to file a Long Range Gas Supply Plan every two years as agreed to by the parties. It voted unanimously to approve the timing. Finally, the PUC approved the BTU Factor of 1.034. The Commission is satisfied that the rates proposed by National Grid and supported by the Division are properly calculated and will ensure that customers pay a just and reasonable rate.

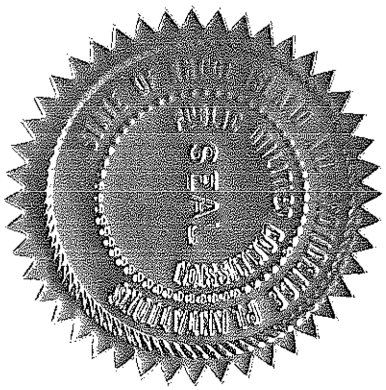
Accordingly, it is

(21449) <u>ORDERED</u>:

1. The Gas Cost Recovery factors of: $0.6381 per therm for Residential Non-Heating customers, Large High Load and Extra Large High Load Factor customers and $0.6626 per therm for Residential Heating customers, Small Commercial and Industrial, Medium Commercial and Industrial, Large Low Load, Extra Large Low Load Factor customers are approved for usage on and after November 1, 2013.
2. The Gas Marketer Transportation factors of: $9.7353 per dekatherm for the FT-2 Firm Transportation Marketer Gas Charge and a weighted average upstream pipeline transportation cost of $0.9383 per dekatherm of capacity are approved for usage on and after November 1, 2013.
3. National Grid shall file a Long Range Gas Supply Plan every two years beginning March 10, 2016.
4. The Natural Gas Portfolio Management Plan shall continue until such time as the PUC determines otherwise.
5. The incentives for the Natural Gas Portfolio Management Plan and the Gas Procurement Incentive Plan are approved. The Company shall not be entitled to earn an incentive for any third party asset management agreement.
6. The Company shall file its Annual GCR Reconciliation by July 1 of each year.
7. The BTU factor of 1.034 is approved.
8. National Grid shall provide electronic versions of all spreadsheets at the time of its initial filing.

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

EFFECTIVE NOVEMBER 1, 2013 IN WARWICK, RHODE ISLAND PURSUANT TO OPEN MEETING DECISIONS ON OCTOBER 25, 2013. WRITTEN ORDER ISSUED APRIL 30, 2014.



PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

Paul J. Roberti, Commissioner

Herbert F. DeSimone, Jr., Commissioner