STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT	**:**	
ELECTRIC COMPANY	**:**	
d/b/a NATIONAL GRID	**:**	
GAS COST RECOVERY CHARGE	**:**	**DOCKET NO. 4520**

REPORT AND ORDER

I. NATIONAL GRID'S FILING

On September 2, 2014, The Narragansett Electric Company d/b/a 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. The instant filing proposed a decrease in rates approved by the PUC earlier, in Docket No. 4436 for the period November 1, 2014 through October 31, 2015. The proposed rates realize in an annual decrease of approximately $48.02 for a typical residential heating customer using the equivalent of 846 therms per year.

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.; 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/4520page.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 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 31, 2014 and the difference between the futures contract purchases under the Gas Procurement Incentive Plan (GPIP) as of July 31, 2014 and the July 31, 2014 NYMEX strip. The factors also reflect storage and inventory costs as of July 31, 2014 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 average NYMEX pricing is lower 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. Beginning with the NYMEX

[2] Arangio Direct at 1-5 (Sept. 2, 2014).

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

Regarding marketer capacity assignment, Ms. Arangio represented that the Company has made available to marketers 32,758 decatherms (Dth) per day of capacity on six 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 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 $0.5553 per Dth to the non-gas Variable Unit Cost of -$0.1545 per Dth to derive the $0.4008 per Dth weighted average pipeline cost. She then added the weighted average pipeline cost to the 100% load factor per unit cost of $0.0072 for the marketer reconciliation adjustment to average pipeline cost of $0.4080 per Dth.[4]

Ms. Arangio explained that National Grid terminated a contract with Transcontinental Gas Pipeline Company for 141 Dths per day of capacity because it was able to secure gas at competitive pricing and save approximately $25,000 in annual fixed charges. She also discussed how the Company took advantage of opportunities for economically-priced domestic shale gas from the Marcellus/Utica region. Ms. Arangio described the Company's various contracts and its plans to supply the East-West Capacity for 2014-2015. She also provided that National Grid entered into contracts to address the limit of sources traditionally available at the interconnect in Beverly, Massachusetts and to replace liquified natural gas (LNG) volumes that are uncertain in

[3] *Id.* at 5-8, Attach. EDA-2.
[4] *Id.* at 8-9, Attach. EDA-4.

the future. National Grid entered into two arrangements for liquid service for the 2014 off-peak refill season. The Company requested additional volume but received less than requested from GDF Suez Gas NA LLC (GDF Suez) to be delivered during the off-peak season to its three New England companies. Ms. Arangio explained that because the volume assigned to Rhode Island did not meet the Company's refill requirement and because GDF Suez would not guarantee additional volumes, National Grid sought additional supplies in the marketplace.[5]

Ms. Arangio identified steps that the Company had taken to address long-term portfolio risks. The first step was to participate in the Algonquin Incremental Market Expansion (AIM Project) and execute a Precedent Agreement. The Company also engaged in negotiations for participation in two other projects. The second step was to continue participation in the LNG Consortium with New England distribution companies and municipally-run companies to find sources of LNG and balance supply with price and delivery sources. National Grid was and is also pursuing its own liquefaction opportunities.

Ms. Arangio provided an overview of the AIM Project. It will, she explained, allow access to gas supplies from the Marcellus Shale region and several other storage fields and interstate pipelines via the Millennium Pipeline at the existing interconnection at Ramapo, New York. It will also allow access to supplies available at the interconnection with the Iroquois Gas Transmission at Brookfield, Connecticut. Ms. Arangio further noted that National Grid anticipates executing a Precedent Agreement to participate in the Tennessee Northeast Expansion Project due to begin service in 2018. Ms. Arangio additionally described the Algonquin Atlantic Bridge Project, which will

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

expand the Algonquin and Maritimes systems and connect the New England states and Maritime Provinces with abundant North American natural gas supplies.[6]

Lastly, Ms. Arangio provided that since last year's GCR hearing, the Company and Bruce Oliver, the Division of Public Utilities and Carriers' (Division) consultant, have engaged in discussions regarding Mr. Oliver's concerns with the current Customer Choice Program. Ms. Arangio noted that National Grid will file a tariff advice proposing changes to the Customer Choice Program.[7]

Ms. Leary provided testimony to propose GCR factors for firm sales service and transportation service. She explained that the proposed GCR factors are load specific, High Load and Low Load, and necessary for the Company to be able to recover the projected gas costs allocated to its firm sales customers for the November 1, 2014 through October 31, 2015 period. For the twelve month period ending October 31, 2015, Ms. Leary stated projected gas costs for the Company's firm sales customers would be approximately $146.4 million. She identified a number of other costs and credits that when added to the costs for the firm sales customers, would total $175.6 million in net costs necessary for the Company to collect.[8]

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 $28.1 million to be allocated to and collected from ratepayers based on their proportion of design-winter use requirements. She provided a GCR Fixed Low Load factor of $1.0659 per Dth and a GCR Fixed High Load factor of $0.8898 per Dth. The

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[6] *Id.* at 21-23.
[7] *Id.* at 23-25.
[8] Leary Direct at 2-4, Attach. AEL-1 (Sept. 2, 2014).

factors resulted from dividing the Fixed Costs by the projected throughput of 26,528,190 Dths for the upcoming year.[9]

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 has been updated and revised to better reflect the difference between projected and actual Fixed Costs paid by marketers during the 2013-2014 and 2012-2013 GCR periods. She identified a net surcharge to Marketers of $80,117 that would be credited to firm sales customers' fixed charges and included in the 2014-2015 pipeline surcharge/credits set forth by Ms. Arangio. She stated that the design-winter calculation was developed using calendar month degree days,[10] consistent with the Commission's finding in Docket No. 4097.[11]

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 2014 through October 2015 period to be $147,555,590. She divided that number by the projected period throughput of 26,528,190 Dths to reach a Variable Cost factor of $5.5622 per Dth. She asserted that an estimated deferred balance under-collection of $29,031,120 at October 31, 2014 is incorporated into the GCR rate as well as the

[9] *Id.* at 5-6.
[10] A change in methodology for determining forecasted design-winter requirements from billing cycle design days to calendar month design-degree days was approved by the Commission in Docket No. 4097, Order No. 19832.
[11] Leary Direct at 6-7, Attach. AEL-7 (Sept. 2, 2014).

projected deferred gas cost balances for the November 2014 through October 2015 period.[12]

Ms. Leary provided that the Company was also proposing changes to the GCR deferral balance for the period April 2013 through March 2014, filed with the Commission on July 1, 2014, to revise the customer excess earnings amount included in the NGPMP and to omit credits that were already included in the Company's Fixed Costs. The changes resulted in a net decrease of $66,185 in the total NGPMP credit and an increase in the amount of deferred gas costs reported in March 2014 of $66,220. She presented a proposed FT-2 marketer demand rate of $8.7038 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.[13]

Ms. Leary hypothesized a possible cause of the increased use by Residential Non-Heating customers was that many of those customers could have converted to gas heat and have not yet been reclassified to the Residential Heating class. She provided that the Company conducted an extensive analysis and determined that a little more than 2,000 non-heating customers had converted to natural gas heat but had not yet been transferred by the Company to the heating rate. She identified approximately 1,000 additional customers who are using more than 1,000 therms per year and have annual load factors that indicate those customers are using gas for heating purposes but did not notify the Company they were doing so. She noted that the Company did not adjust its sales forecast to reflect the reclassification of these approximately 3,000 customers because any impact would be minimal. Finally, Ms. Leary identified an approximate $48.02

[12] *Id.* at 7-8, Attach. AEL-1, AEL-3.
[13] Leary Direct at 8-10, Attach. AEL-2, AEL-5, AEL-6 (Sept. 2, 2014).

annual reduction to a residential customer using 846 therms per year resulting from the proposed rates.[14]

Mr. McCauley discussed the results of the GPIP[15] for the period July 1, 2013 through June 30, 2104 and the results of the NGPMP for April 1, 2013 through March 31, 2014 and recommended that the NGPMP continue after March 31, 2014. The GPIP incentive or penalty is determined by multiplying the total savings or cost by 10%. The total savings is multiplied by 20%, however, for those 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 Company calculated a $60,078 incentive which Mr. McCauley proposed be granted in full. He also discussed the Company's request that the Commission allow the Company additional market area basis hedges to the GPIP for the winter period November 2014 through March 2015. Mr. McCauley provided that, if allowed, the Company's forecasted gas costs would increase by approximately $788,000, which would result in a minimal impact to gas costs.[16]

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 that savings realized are greater than those realized with a third party

[14] *Id.* at 10-13.
[15] 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.
[16] McCauley Direct at 3-7, Attach. SAM-1, SAM-1a, SAM-2 (Sept. 2, 2014).

manager. Noting that the NGPMP is currently in its third year,[17] Mr. McCauley said it has saved the Company approximately $8.4 million. He noted that the program passed approximately $6.9 million of those savings on to customers, while the Company received 20% of the total of savings in excess of $1 million or $1,474,167 for the April 2013 through March 2014 period. Mr. McCauley noted that the Company does not include any revenue from Asset Management Agreements in the incentive and is not proposing any changes to the NGPMP incentive at the current time. He requested continuation of the NGPMP.[18]

On September 16, 2014, Ms. Arangio and Ms. Leary (collectively, the witnesses) filed Supplemental Direct testimony to address the impact on the GCR factors resulting from the Company's hedging proposal for the upcoming winter season and its proposal to change the FT-2 Demand rate included in the proposed changes to the Gas Customer Choice Program. In addition to the testimony, the witnesses filed a number of schedules setting forth the factors. The witnesses identified an increase to the High Load factor GCR from $0.6663 per therm to $0.6692 per therm and an increase to the Low Load factor GCR from $0.6845 per therm to $0.6871 per therm over what the Company originally proposed in its September 2, 2014 filing. They noted that the increase resulting from approval of the two proposals would still result in the average residential customer using 846 therms per year experiencing a decrease of approximately $106.55 or 8.1% over what that customer paid last year.[19]

[17] The Commission approved the NGPMP in Docket No. 4038, Order No. 19627 on March 31, 2009.
[18] McCauley Direct at 8-9, Attach. SAM-3 (Sept. 2, 2014).
[19] Arangio /Leary Supplemental Direct at 1-5 (Sept.16, 2014).

II. DIVISION OF PUBLIC UTILITIES AND CARRIERS' FILING

To address National Grid's filing, the Division of Public Utilities and Carriers (Division) submitted the testimony of Bruce R. Oliver, its consultant.[20] The Division subsequently filed a revised version of Mr. Oliver's testimony. The revised testimony eliminated an allegation that National Grid does not file a monthly GCR Deferred Gas Cost Balance Report with 12 months of actual data. It also made minor changes to the exhibits and included a number of elucidative observations:

1) The Company's proposed GCR charges represent a decrease of the charges approved in April 2014, but an increase of those approved in November 2013.
2) Forecasted gas costs are 4.2% lower than in the November 2013 filing.
3) The decrease in projected Supply Variable Costs offsets an increase in projected Storage Variable Costs.
4) The projected deferred gas cost balance for October 31, 2014 is $28.4 million which offsets the reductions in Fixed and Variable Gas Costs that the Company had achieved.
5) National Grid should re-examine its charges for Transitional Sales Service (TSS) as its surcharge for this service appears inadequate.
6) Non-Firm gas costs do not include gas costs associated with unauthorized gas use by Non-Firm customers during January through March 2014.
7) There is need for further assessment of the impact of transferring approximately 3,000 customers from Residential Non-Heating service rates to Residential Heating service rates.[21]

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[20] Oliver Direct (Oct. 6, 2014).
[21] Oliver Revised Direct at 3-5 (Oct. 17, 2014).

Additionally, Mr. Oliver recommended that the Commission:

1) Accept the Customer Choice Program revisions to mitigate the adverse impacts on current market practices;
2) Find the proposed adjustments to the GCR, to reflect the Local Market Hedging Program and the Customer Choice Program, reasonable and appropriate;
3) Require National Grid to document and explain all individual customer billing adjustments greater than 10,000 Dth;
4) Approve the GPIP and NGPMP incentives; and
5) Allow for the reclassification of the approximate 3,000 residential non-heating customers to residential heating.[22]

Mr. Oliver noted that part of the Commission's 2014 Order[23] required National Grid to review its hedging program and to look for other means of limiting daily spot market purchases during extreme weather. The Order further required the Company to review the terms under which its marketers deliver gas to the Company, the pricing for customers who return to gas supply service, and non-firm customer compliance with service interruptions, as well as the adequacy of penalties for noncompliance. Mr. Oliver asserted that National Grid has worked with the Division to comply with the terms of that Order.[24]

Although he did not question the accuracy or computation of the GCR Reconciliation, Mr. Oliver noted that there were large billing adjustments made with no explanation and that there were inconsistencies between Non-Firm gas costs credited to

[22] *Id.* at 6-7.
[23] Docket No. 4436, Order No. 21465 (May 15, 2014).
[24] Oliver Revised Direct at 7-9.

Firm gas costs in the Company's reconciliation filing and the Non-Firm gas costs identified in Yi-An Chen's[25] Schedules submitted with her Distribution Adjustment Charge testimony. He had concerns with the Company's development and use of forecast sales and throughput data which, he stated, raised questions regarding the appropriateness and reliability of the forecasted annual throughput and design-winter sales volumes. Specifically, he noted that as compared to last year, there were large shifts in the distribution of usage by month with neither explanation nor support for those shifts. He noted inconsistencies between design-winter and normal winter forecast data. He identified a number of instances where forecasted sales under design-winter conditions were less than those forecasted under normal weather conditions for the same month. Finally, he found that forecasted sales were not adjusted to reflect the reassignment of the Residential Non-Heating customers to the Residential Heating class.[26]

Mr. Oliver recommended that the Commission approve the Company's proposed modifications to the Customer Choice Program noting that the impact of such would not be significant. He provided that the $788,000 or 0.5% of overall gas costs for the year increase that would result from the Commission's approval of the Company's Market Area Hedging Plan would save ratepayers more than $10 million should the coming winter be similar to last year's. He found the $60,078 GPIP incentive and the $1,474,167.13 NGPMP incentive calculations to be reasonable and recommended approval. Finally, he was unable to provide the Division's position on the Company's intent to transfer a number of Residential Non-Heating customers to the Residential

[25] Ms. Chen is a Senior Analyst in the Regulation and Pricing Department for National Grid USA Service Company Inc.
[26] Oliver Revised Direct at 13-19.

Heating class because National Grid had neither identified the actual number to be transferred nor provided adequate usage details of those customers.[27]

III. NATIONAL GRID'S REBUTTAL

National Grid filed the rebuttal testimony of Ms. Leary addressing each of Mr. Oliver's concerns. Regarding the TSS rate, Ms. Leary represented that the Company was willing to discuss any changes with the Division. She stated that the Deferred Cost balance was based on actual data. She noted that the Company reconciled its Non-Firm Gas Cost Revenue and that there was a timing difference. Specifically, she said that $59,000 of unauthorized gas usage charges would be included in next year's GCR filing. Regarding the large billing adjustments of greater than 10,000 Dth for twenty-nine customers, Ms. Leary explained most of these were caused by meter error, rate assignments, or rebilling due to incorrect supply. She noted that 73% of the customers being transferred from the Residential Non-Heating class to the Residential Heating class used between 600 and 1,500 therms annually. She identified the range of bill impacts resulting from the transfer of those customers as between a 2.2% increase for the customer using 600 therms annually to a 9% decrease for the customer 1,500 therms annually. She noted that the incremental revenue from customers who have been transferred from TSS to Default Transportation Service is reflected in the GCR revenues. Finally, she provided that although the Company believes its design-winter sales forecast is correct, it is amenable to further review with adjustments if necessary.[28]

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[27] *Id.* at 20-27.
[28] Leary Rebuttal at 1-8 (Oct. 17, 2014).

HEARING

At the hearing on October 23, 2014, 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. The witnesses were questioned about Mr. Oliver's concern with the TSS surcharge. Ms. Leary offered that the Company was planning to file a revised tariff by January 1, 2015. She also provided clarification regarding the $59,000 adjustment for unauthorized gas charges from January to March 2014, noting that it resulted from a billing lag and was not likely to occur again. When questioned about the twenty-nine customers who had billing adjustments of greater than 10,000 decatherms, Ms. Leary testified that the Company had implemented a number of processes to eliminate recurrence of these same issues.[29]

Ms. Leary discussed the steps taken to ensure that customers are in the appropriate rate class. She noted that National Grid was also evaluating additional processes, including coordination with the processes used in the Commercial and Industrial program, to review customers' usage and exceptions to annual usage. With regard to the unbilled $104,285 attributable individuals improperly classified as Residential Non-Heating customers, Ms. Leary stated that the Company could not bill those charges because it could not ascertain the date those customers had converted to gas heat. Because the amount was insignificant, she added, it was unlikely that customers were gaming the system by not notifying the Company of conversions in an effort to avoid additional costs. Ms. Leary explained that the Company was able to propose a

[29] Hr'g Tr. 20-24 (Oct. 23, 2013).

decrease in rates when its deferred balance is $28.2 million because commodity costs are forecasted to decrease by about $25 million.[30]

Regarding the Company's LNG supply, Ms. Arangio noted that the bulk came from Distragas and was used strictly for gas customer service. She provided that over the last few years LNG costs have increased steadily, plateauing only during the last year. Mr. McCauley testified about the Company's asset management program, identifying approximately $7.1 million of customer savings last year. He noted that customer savings have increased each year since the program began five years ago. Ms. Arangio explained how load forecasts are determined by models and are updated on an annual basis using actual data from the prior year. She testified that the Company plans and sets rates based on a normal winter, but for gas supply it plans for a design-weather.[31]

The Division presented Mr. Oliver who commended the Company on its willingness to address the issues he raised. He reiterated the concerns set forth in his prefiled testimony. He recommended that the Commission approve the rates proposed by the Company.[32]

COMMISSION FINDINGS

Immediately following the hearing, the Commission approved a High Load GCR Charge of $0.6692 per therm for Residential Non-Heating, Large High Load, and Extra Large High Load classes. It approved a Low Load GCR Charge of $0.6871 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 $8.5224 per dekatherm per month and a weighted

[30] *Id.* at 24-51.
[31] *Id.* at 52-73.
[32] *Id.* at 84-100.

average upstream pipeline transportation cost of $0.5039 per dekatherm of capacity for usage on and after November 1, 2014.

The Commission found the Company's request for the $60,078 incentive on its Gas Procurement Incentive Plan and the NGPMP incentive of $1,474,167 to be fair and reasonable and approved the same. As previously held, the Company shall not be allowed to earn an incentive on its third-party asset management agreements and the NGPMP shall continue until such time as the Commission finds otherwise. Finally, the PUC approved the BTU Factor of 1.029. The Commission is satisfied that the rates proposed by National Grid and supported by the Division were properly calculated and will ensure that customers pay a just and reasonable rate.

Accordingly, it is

(21924) ORDERED:

1. The Gas Cost Recovery factors of:
   a. $0.6692 per therm for Residential Non-Heating customers, Large High Load and Extra Large High Load Factor customers, and
   b. $0.6871 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, 2014.
2. The Gas Marketer Transportation factors of:
   a. $8.5224 per dekatherm for the FT-2 Firm Transportation Marketer Gas Charge, and

b. a weighted average upstream pipeline transportation cost of $0.5039 per dekatherm of capacity

are approved for usage on and after November 1, 2014.

3. The incentives for the Natural Gas Portfolio Management Plan and the Gas Procurement Incentive Plan are approved.
4. The Company shall file its Annual Gas Cost Recovery Reconciliation by July 1 of each year.
5. The BTU factor of 1.029 is approved.
6. National Grid shall provide electronic versions of all spreadsheets at the time of its initial filing.
7. National Grid shall comply with the reporting requirements and all other findings and directives contained in this Report and Order.

EFFECTIVE NOVEMBER 1, 2014 IN WARWICK, RHODE ISLAND PURSUANT TO A BENCH DECISION ON OCTOBER 23, 2014. WRITTEN ORDER ISSUED JUNE 3, 2015.

PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

Paul J. Roberti, Commissioner

Herbert F. DeSimone, Jr., Commissioner