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August 10, 2018

Via Electronic Mail and Hand Delivery

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4755 – 2018 Energy Efficiency Program Plan
Responses to Division Data Requests – Set 2

Dear Ms. Massaro:

I have enclosed ten copies of National Grid's[1] responses to the second set of data requests issued by the Rhode Island Division of Public Utilities and Carriers (Division) in the above-referenced docket.

This filing also contains a Motion for Protective Treatment of Confidential Information in accordance with Rule 1.2(g) of the Public Utilities Commission's (PUC) Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). National Grid seeks protection from public disclosure of certain confidential and privileged information, which is contained in its responses to Division 2-15. In compliance with Rule 1.2(g), National Grid has provided the PUC with one complete, unredacted copy of the confidential materials in a sealed envelope marked **"Contains Privileged and Confidential Materials – Do Not Release",** and has included redacted copies of the materials for the public filing.

Thank you for your attention to this filing. If you have any questions concerning this matter, please contact me at 401-457-5164.

Very truly yours,

Adam M. Ramos
Enclosures
cc: Docket 4755 Service List
Jon Hagopian, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon — August 10, 2018
Date

Docket No. 4755 - National Grid – Energy Efficiency Program Plan for 2018
Docket No. 4756 - National Grid – 2018 System Reliability Procurement Report (SRP)
Service list updated 7/9/18

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
BEFORE THE PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID – ELECTRIC AND GAS DISTRIBUTION RATE FILING	)	Docket No. 4755

THE COMPANY'S MOTION
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

The Company[1] respectfully requests that the Rhode Island Public Utilities Commission (PUC) provide confidential treatment and grant protection from public disclosure of certain confidential and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws. § 38-2-2(4)(B). The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On August 10, 2018, the Company filed its responses to the Rhode Island Division of Public Utilities and Carriers' (the Division) Second Set of Data Requests in Docket 4755 from the Division of Public Utilities to National Grid dated July 10, 2018 (Division Set 2). The responses to these data requests from Division Set 2 include responses to Data Request Division 2-15 requesting, "the electric interconnection to the National Grid system that serves the Navy at the proposed location of the CHP unit." The response to this data request includes CONFIDENTIAL Attachment DIV 2-15. This attachment contains information describing the precise location of electrical interconnections at Naval Station Newport. This information

[1] The Narragansett Electric Company d/b/a National Grid (the Company).

concerning energy infrastructure is sensitive and if released to the public, individuals with a desire to disrupt the electric grid could use this information to locate interconnections and potentially disrupt aspects of the gas and electric distribution systems. Therefore, the Company requests that, pursuant to Rule 1.2(g), the PUC afford confidential treatment to CONFIDENTIAL Attachment DIV 2-15.

II. LEGAL STANDARD

PUC Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). Therefore, to the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of the APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely either to (1) impair the Government's ability to obtain necessary information in the future; or (2) cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I. 2001). Disclosure of information

would impair the Government's ability to obtain such information in the future when: (a) information is provided voluntarily to the governmental agency, and (b) that information is of a kind that customarily would not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

III. BASIS FOR CONFIDENTIALITY

The information contained in CONFIDENTIAL Attachment DIV 2-15 is confidential and proprietary. Specifically, this attachment contains information that the company has created to describe the location and nature of the proposed electrical interconnection at Naval Station Newport. This information is not made available to the general public. If the Company makes the reports contained within this attachment available to the public, then it will reveal technical aspects of the structure of the electrical grid. Making this information publicly available could create vulnerabilities in the electric grid by making it easier for individuals to disrupt certain aspects of it. The Company, therefore, is providing CONFIDENTIAL Attachment DIV 2-15 to the PUC on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to this attachment and the response.

IV. CONCLUSION

Accordingly, the Company respectfully requests that the PUC grant protective treatment to CONFIDENTIAL Attachment DIV 2-15.

WHEREFORE, the Company respectfully requests that the PUC grant this Motion for Protective Treatment.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY

By its attorney,

Adam M. Ramos, Esq. (RI #7591)
Hinckley, Allen & Snyder LLP
100 Westminster Street, Suite 1500
Providence, RI 02903-2319
(401) 457-5164

Dated: August 10, 2018

Division 2-1

Request:

Referring to the response to Division 1-1, the question requested the Company to "describe in detail the assumptions and methodologies that were used to estimate the economic and environmental benefits of the Navy's CHP Project." The response did not describe the assumptions in detail, but cross-referenced program documents. Please provide a narrative description of all the assumptions for the incremental economic benefits and why the Company believes it is reasonably likely that the Navy's CHP Project will achieve the $16 million of "Econ $ benefits" shown in the chart in the response to Division 1-2, which benefits would not otherwise have been achieved without the CHP unit.

Response:

The Navy CHP Project's economic benefits are assessed consistently with the RI Test as approved in Docket No. 4755.

As stated in the Company's 2018 Energy Efficiency Program Plan, "For all CHP projects, net economic development benefits will be counted as benefits. The rate of economic development benefit will be $0.80 of lifetime gross state product increase per dollar of program investment, based on the report, "Macroeconomic Impacts of Rhode Island Energy Efficiency Investments: REMI Analysis of National Grid's Energy Efficiency Programs, prepare by National Grid in August 2014."[1] The report in its entirety is attached as Attachment DIV 2-1.

The CHP multiplier is an output of the Regional Economic Models Inc. (REMI) model utilized in this analysis. A portfolio of CHP projects were used to inform the inputs to the REMI model in order to produce an economic multiplier that could be applied to all CHP projects. The CHP multiplier is a representation of how the average CHP project impacts the local economy and is not specific to any one project. As stated above, this method has been the approved approach for the application of economic multipliers in the RI Test for CHP projects.

Table 6 from the REMI analysis summaries the inputs and outputs associated with CHP projects:

[1] National Grid 2018 Energy Efficiency Program Plan (Docket 1755) Attachment 4, Page 12.

Division 2-1, page 2

CHP PROJECT ECONOMIC MULTIPLIERS							
CHP Project Data		Job Years/$m	Job Years	GDP/$	GDP	Income/$	Income
Construction Spending	$3,761,172	12.4	47	0.8	$3,034,363	0.6	$2,244,149
Total Savings	$12,042,883	14.1	170	1.5	$17,568,939	1.1	$12,703,018
Total Cost	$6,268,620	-6.6	-41	-0.5	-$3,506,352	-0.3	-$2,126,284
		Total	175	Total	$17,096,950	Total	$12,820,883
TOTAL SPENDING MULTIPLIERS							
		Jobs/$m	Job Years	GDP/$	GDP	Income/$	Income
Total Spending	$6,268,620	28.0	175	2.73	$17,096,950	2.0	$12,820,883

The economic multiplier associated with the construction impacts of a CHP project is $0.80 increase in state gross domestic product (GDP) per dollar of program and participant spend (total project cost). The $0.80 CHP multiplier was applied to the Navy CHP total project cost, resulting in total one-time economic benefits of $16 million.

The economic benefits are reasonable for several reasons. First, as stated in the 2018 EEPP, the Company only counts the economic benefits associated with the construction phase spending of a CHP project in the RI Test to ensure there is no double counting of costs and benefits in benefit/cost screening.

Second, as described in the Company's 2014 REMI Analysis, CHP projects impact the Rhode Island economy during the construction phase when program and participant spending on a CHP project creates jobs in construction and other industries as the projects are planned, and equipment is installed. The majority of the equipment purchase costs is assumed to occur outside of the region, and is therefore excluded as a local economic impact in the REMI analysis.[2]

Third, the $0.80 economic multiplier is a more conservative multiplier than was used in Energy Efficiency Program Plans (EEPP) prior to 2018. The Toray CHP project was screened using a $2.73 economic multiplier. These two multipliers are both outputs from the REMI Analysis. The $0.80 multiplier only reflects the impacts to the local economy from the construction phase of the project, whereas the $2.73 multiplier is the total output of the REMI model.

[2] Macroeconomic Impacts of Rhode Island Energy Efficiency Investments: REMI Analysis of National Grid's Energy Efficiency Programs", National Grid Customer Department, November, 2014, Page 11.

Division 2-1, page 3

The REMI Analysis, the change from the $2.73 to $0.80 multiplier, and the application of the economic multiplier for all CHP projects as part of the RI Test was vetted and discussed at the PUC Technical Session on September 13. 2017. The Company, alongside the Division of Public Utilities and Carriers consultant Tim Woolf participated in this session. This methodology was approved by the PUC as part of the 2018 EEPP on January 9, 2018.

Macroeconomic Impacts of Rhode Island Energy Efficiency Investments

REMI Analysis of National Grid's Energy Efficiency Programs

National Grid Customer Department

October 2014

EXECUTIVE SUMMARY

This study quantifies the macroeconomic impacts of National Grid's 2014 Energy Efficiency (EE) Program Plan for Rhode Island and provides updated economic impact multipliers to quantify the benefits of future EE programs in the Rhode Island economy. National Grid and the Energy Efficiency Resource Management Council (EERMC) currently use multipliers from an economic impact study conducted by Environment Northeast (ENE) in 2009[1]. The ENE Study did not address Combined Heat and Power (CHP) projects, which have since become incorporated into Rhode Island's EE plans. Therefore, this study also provides estimates of the economic development benefits of CHP projects.

National Grid and its customers will invest $112.5 million on EE electric and gas measures in Rhode Island under the 2014 Plan, as shown in Table ES-1[2]. This will create jobs in construction and other industries as EE materials and equipment are purchased and installed in homes and businesses. Once implemented, the EE measures will provide net cost savings (energy and non-energy) to customers over the fourteen-year life of the program. This will increase economic activity, incomes and employment in Rhode Island over the long-term. These economic impacts are estimated using the policy forecasting model by Regional Economic Models, Incorporated (REMI) as the difference between a base case with no EE program spending and the case with 2014 EE Plan spending[3]. Thus, all economic impacts greater than zero are attributable to the Plan. Both the ENE Study and National Grid used the REMI model to estimate the economic impact of Rhode Island EE program plans in this way.

Table ES-1
2014 Energy Efficiency Investment Spending ($m)

ELECTRIC	RESIDENTIAL	C&I	TOTAL
Program Budget	$33.7	$34.8	$68.5
Customer Contribution	$6.8	$9.3	$16.1
Total Electric	$40.6	$44.1	$84.64
GAS	RESIDENTIAL	C&I	TOTAL
Program Budget	$14.2	$8.2	$22.4
Customer Contribution	$3.2	$2.2	$5.4
Total Gas	$17.4	$10.4	$27.8
Total Electric and Gas	$58.0	$54.5	$112.5

Table ES-2 below shows the economic impact of the above spending targets based on REMI estimates. The 2014 Plan is expected increase employment by a total of 3,607 job years in Rhode Island over the next fourteen years (a "job year" is equal to one full-time job for a period of one year). Also, the Plan is expected to add $331 million to state gross domestic product (GDP), $224 million to personal income and $15 million to state

[1] Jamie Howland, Derek Murrow, Lisa Petraglia and Tyler Comings, "Energy Efficiency: Engine of Economic Growth, A Macroeconomic Modeling Assessment," Environment Northeast, October 2009 (referred to herein as the "2009 ENE Study" or "ENE Study").
[2] The Toray Plastics (America), Inc. Combined Heat and Power (CHP) project was removed from this analysis as this study examines the economic impacts of CHP separate from EE. Residential includes income eligible customers.
[3] REMI is owned by Regional Economic Models, Incorporated and leased to its clients. See www.remi.com for model description, applications, client lists and documentation.

tax revenue. This equates to an average annual impact of 258 jobs, $24 million in GDP, $17 million in personal income and $1.1 million in state tax revenue over the next fourteen years. These are net economic gains, after all program and participant costs have been paid.

Table ES-2, 2014 EEPP Net Economic Benefits

PROGRAM LIFETIME IMPACT (2014-2027)	ELECTRIC	NATURAL GAS	TOTAL
Job Years	3,093	514	3,607
GDP ($2014m)	$287	$44	$331
Personal Income ($2014m)	$211	$33	$244
State Tax Revenue ($2014m)	$13	$2	$15

AVERAGE ANNUAL IMPACT (2014-2017)	ELECTRIC	NATURAL GAS	TOTAL
Jobs	221	37	258
GDP ($2014m)	$20.5	$3.1	$24
Personal Income ($2014m)	$15.0	$2.4	$17
State Tax Revenue ($2014m)	$0.9	$0.1	$1.1

A major objective of the National Grid Study is to update the ENE spending multipliers to quantify the benefit of future EE Plans to the Rhode Island economy. In its 2009 study, ENE estimated that every $1.0 million in electric EE program spending in Rhode Island would create 36.2 job years while every $1.0 million in gas EE spending would create 38.5 jobs years. ENE also estimated impacts on Rhode Island GDP, output, value added and income.

However, changes in EE program benefits and costs since 2009 imply that these spending multipliers have changed. First, there has been a significant decline in natural gas prices, leading to lower benefit cost ratios for gas EE programs. This implies fewer economic benefits for every dollar spent on gas EE programs. Second, program offerings have evolved with changes in technology and markets. As a result, the distribution of spending, benefits and costs between residential and commercial and industrial (C&I) customers differs from what was assumed in the ENE Study. Since costs and benefits to C&I customers tend to have a larger economic impact than to residential customers, this also implies a change in the amount of economic benefits for every EE dollar spent. Benefit cost ratios can also change over time due to changes in technology, markets and program offerings, causing spending multipliers to change.

Table ES-3 below provides a comparison of the updated spending multiplier estimates on employment and GDP to those found in the ENE Study. These multipliers include the impact of program and participant spending, lifetime benefits, and program and participant costs.

Updated electric spending multipliers are higher than those from the ENE Study. Benefit cost ratios are close, but the 2014 electric plan has a higher share of C&I participants in total benefits and a lower share of C&I participants in total costs, implying a larger economic impact for every EE dollar spent. Updated gas spending multipliers are lower than the ENE Study. This is due to the drop in natural gas prices since 2009, which has reduced the benefit cost ratio of gas EE programs. In addition, the 2014 EE gas plan has a lower share of C&I participants in total benefits and a higher share of C&I participants in total costs compared to the ENE Study.

Table ES-3
COMPARISON OF RESULTS TO 2009 ENE STUDY

	Job Years / $ Million			GDP / $		
	Electric	Gas	Total	Electric	Gas	Total
2014 EE Program Plan Study						
Program Spending / Budget	45.1	23.0	39.7	4.2	1.9	3.6
Pgm and Part Spending / Pgm Cost	36.5	18.5	32.1	3.4	1.6	2.9
2009 ENE Study						
Program Spending / Budget	36.2	38.5	37.4	4.0	4.4	4.2
Pgm and Part Spending / Pgm Cost	27.0	25.5	26.3	3.0	2.9	3.0

Combined Heat and Power

The ENE Study did not address Combined Heat and Power (CHP) projects which have since become incorporated into Rhode Island's EE plans. CHP projects involve the installation of equipment to generate electricity and capture waste heat for productive uses such as facility heating and cooling. CHP projects must pass a benefit cost test to be included in National Grid's EE Plan, but economic development benefits may be included in the test. CHP economic benefits result from spending to install cogeneration equipment (positive construction impacts) and from energy cost savings to program participants, net of participant and ratepayer costs. National Grid and the EERMC currently use a rate of economic development benefit of $2.51 of lifetime GDP increase per dollar of CHP program investment. This multiplier was estimated by adjusting EE program multipliers from the 2009 ENE study to reflect the lower benefit cost ratios of most CHP projects.

However, given the inherent differences between EE and CHP projects, National Grid and the EERMC requested this study to determine a CHP multiplier based on actual spending, benefit and cost data from typical CHP projects. Massachusetts CHP data was used because it has a longer history with more projects than Rhode Island. In fact, Rhode Island currently has only one CHP project, Toray Plastics (America), Incorporated, which is much larger and somewhat atypical of most CHP projects.

Benefit, spending and cost data for six representative Massachusetts CHP projects are shown in Table ES-4. These are cogeneration projects in which gas-fired equipment is installed to simultaneously generate electricity and useful heat.

Table ES-4

MA Combined Heat and Power Project Data					
Number of Projects	6	**Project Spending**		**CHP Project Costs**	
Benefit Cost Ratio	1.92	Incentive	$1,565,250	Incentive	$1,565,250
Measure Life	20	Customer	$4,703,370	Customer	$4,703,370
Total Benefits	**$12,042,883**	**Total Spending**	**$6,268,620**	**Total Costs**	**$6,268,620**

Total benefits in Table ES-4 are lifetime electricity and heating cost savings, net of increased natural gas and O&M costs needed to run the cogenerating equipment. Spending consists of National Grid's incentive payment and customer contributions to purchase and install the CHP systems. Costs are equal to spending to purchase and

install the CHP systems, before federal tax credits and other state incentives.[4] The average lifetime of the CHP projects is 20 years and the average benefit cost ratio is 1.92.

CHP economic benefits are estimated using the REMI model for Rhode Island and the Massachusetts CHP data shown in Table ES-4. Results are summarized in Table ES-5 below as job year, GDP and income multipliers on total CHP program and participant spending. The multipliers reflect net CHP economic benefits after all costs have been taken into account, including the cost of fuel switching.

Table ES- 5
Combined Heat and Power Economic Benefits
Multipliers on Total Program and Participant Spending

Job Years / $m	**28.0**
GDP / $	**2.73**
Personal Income / $	**2.0**

At $2.73, the GDP multiplier on total CHP spending is close to the current estimate of $2.51 used by the EERMC. However, it is significantly higher than the GDP multiplier on total gas EE program spending shown in Table ES-3 above, $1.60. This is because low natural gas prices have reduced the value of energy savings from gas EE programs and hence the economic impact per dollar of gas EE program and participant spending. On the other hand, lower gas prices have increased cost savings that CHP programs bring to participants from switching to gas-fired cogeneration to provide electricity and heat. Moreover, Table ES-4 shows that the average measure life of the CHP programs is 20 years, which is 6 years more than the 14 year measure life of the gas EE programs, increasing CHP lifetime benefits relative to gas EE programs. Both factors lead to a higher benefit cost ratio for the representative Massachusetts CHP programs than for the gas EE programs.

[4]CHP projects in both Massachusetts and Rhode Island qualify for the federal investment tax credit. State incentives include the monetized value of renewable energy credits associated with electricity generated from CHP projects.

INTRODUCTION

National Grid has been implementing energy efficiency (EE) programs in Rhode Island since 1987. These programs produce benefits long after all program and participant costs have been paid as measure lifetimes are in the 12 to 15-year range. In addition to electricity and gas savings, the programs provide other benefits such as reduced oil and water consumption, lower operation and maintenance costs, increased productivity and lower emissions. While the above benefits are the driving force behind National Grid's EE programs, there are also significant economic development benefits that make them even more valuable.

Macroeconomic Impacts of Energy Efficiency Programs

Energy efficiency programs impact the local economy in three ways. First, program and participant spending represents a direct investment in Rhode Island EE infrastructure. This creates jobs in construction and other industries as the programs are planned, and materials and equipment are purchased and installed. This is known as the "construction impact," taking place during "construction phase" of the Plan. The full impact is typically felt in the single year that the EE investment is made and the program is implemented.

Second, program savings to residential and business customers have positive economic impacts over the life of the EE measures. Residential savings put more money in consumer's pockets, boosting spending on local goods and services. This leads to more activity and hiring, especially in service sector industries such as retail. Commercial and industrial (C&I) cost savings increase regional competitiveness, allowing firms to sell more in competitive markets. This leads to increased output and hiring.

Third, rate increases and customer contributions needed to pay for the measures raise business costs and reduce consumer spending on other goods and services, lowering EE program economic benefits. This is a short-term impact. Program costs are paid for in a single year by the energy efficiency program charge to all electric and gas customers. Customer costs are usually paid off in 1 to 3 years.

Methodology

The total economic impact of EE programs equals the sum of the program and participant spending (construction phase), savings and cost impacts. The sections below explain how each of these economic impacts are estimated in REMI for both the 2014 EEPP and for the representative CHP projects. The final section summarizes results for each of these economic impacts and adds them up to obtain the total impacts shown in the Tables ES-2, ES-3 and ES-5 of the Executive Summary. The final section also explains how use of multipliers on the individual economic impacts of EE programs and CHP projects may provide a more robust evaluation of future plans than the use of total spending multipliers only.

Estimating Construction Impacts

To estimate EE program construction impacts, program and participant spending is entered into REMI as an exogenous increase in final demand in the industries where the money is expected to be spent. Allocation of residential and C&I spending to these

industries is taken from the ENE Study[5]. This includes separate allocations for program and participant spending by customer segment, residential and C&I.

EE spending by industry is shown on Table 1. Although most spending is expected to take place in the construction industry, a significant amount of spending is also expected in machinery manufacturing, which includes heating, ventilation and air conditioning equipment, as well as commercial refrigeration equipment; electrical equipment manufacturing, which includes lighting fixtures and appliances; professional services, which includes planning and engineering; retail trade, and utilities.

Table 1
ELECTRIC AND GAS, PROGRAM AND PARTICIPANT SPENDING, BY RI INDUSTRY

	Electric					Gas					Total
	Program		Participant		Electric	Program		Participant		Gas	Elec & Gas
	Res	C&I	Res	C&I	Total	Res	C&I	Res	C&I	Total	Total
Wood Products	$0.3	$0.0	$0.1	$0.0	$0.4	$0.1	$0.0	$0.0	$0.0	$0.2	$0.6
Nonmetallic mineral product mfg	$0.3	$0.3	$0.1	$0.1	$0.8	$0.1	$0.1	$0.0	$0.0	$0.3	$1.0
Paper	$0.7	$0.0	$0.1	$0.0	$0.8	$0.3	$0.0	$0.1	$0.0	$0.3	$1.2
Machinery mfg	$1.0	$3.3	$0.2	$1.0	$5.5	$0.4	$0.8	$0.1	$0.2	$1.5	$7.0
Computer, electronic prod mfg	$0.3	$1.0	$0.1	$0.3	$1.7	$0.1	$0.2	$0.0	$0.1	$0.5	$2.2
Electrical equip, appliance mfg	$0.7	$3.8	$0.1	$1.1	$5.8	$0.3	$0.9	$0.1	$0.3	$1.5	$7.3
Plastics, rubber prod mfg	$0.7	$0.6	$0.1	$0.1	$1.5	$0.3	$0.1	$0.1	$0.0	$0.5	$2.0
Wholesale trade	$0.3	$0.7	$0.1	$0.2	$1.3	$0.1	$0.2	$0.0	$0.0	$0.4	$1.7
Construction	$20.9	$18.2	$4.8	$5.5	$49.3	$8.8	$4.3	$2.3	$1.3	$16.6	$66.0
Retail	$5.1	$0.0	$1.2	$0.0	$6.2	$2.1	$0.0	$0.5	$0.0	$2.7	$8.9
Prof. Services	$1.3	$4.9	$0.0	$1.0	$7.2	$0.6	$1.1	$0.0	$0.2	$2.0	$9.2
Utilities	$2.0	$2.1	$0.0	$0.0	$4.1	$0.9	$0.5	$0.0	$0.0	$1.3	$5.5
Total	$33.7	$34.8	$6.8	$9.3	**$84.6**	$14.2	$8.2	$3.2	$2.2	**$27.8**	**$112.5**

Direct, Indirect and Induced Impacts

Jobs created during the construction phase of EE programs result from the direct, indirect and induced impact of EE investment spending. Direct impacts are tied directly to the program, for example, the number of contractors hired to install efficiency measures in businesses and homes, as well as program administrators. Indirect impacts are felt in the local supply chain, that is, industries providing goods and services for the projects. Induced impacts result from the spending of the direct and indirect workers and are felt mainly in the local service sector, for example, increased retail activity and hiring.

The total economic impact of EE spending during the construction phase is the sum of the direct, indirect and induced impacts. REMI estimates the total impact of EE spending, including the direct, indirect and induced impacts, but does not disentangle them.

Construction Phase Economic Impact Results

Table 2 shows the total economic impact of EE spending during the construction phase. Job year, GDP and income impacts shown are for the program and participant spending targets in Table ES-1 of the Executive Summary, above. REMI estimates that the $112.5 million spending plan will create 1,044 job years in Rhode Island in 2014, before

[5] 2009 ENE Study, Appendix 1.

program and participant costs are taken into account. This amounts to 9.3 job years for every $1 million of EE program and participant spending, including the direct, indirect and induced impacts.

This is independent of the job years created as a result of the program benefits, such as energy cost savings, which are discussed below. The 2014 impact on Rhode Island GDP and real personal income is $72.6 million and $51.6 million, respectively.

Table2

SUMMARY OF 2014 CONSTRUCTION IMPACTS (BEFORE COSTS)

Employment Impact	Electric		Natural Gas		Total	
	Job Years	Job Yrs / $m Spending	Job Years	Job Yrs / $m Spending	Job Years	Job Yrs / $m Spending
Program Spending	623	9.1	212	9.5	835	9.2
Participant Spending	155	9.6	55	10.1	209	9.7
Total	777	9.2	267	9.6	1,044	9.3

GDP Impact ($2014m)	Electric		Natural Gas		Total	
	GDP	GDP / $ Spending	GDP	GDP / $ Spending	GDP	GDP / $ Spending
Program Spending	$43.6	0.6	$14.8	0.7	$58.4	0.6
Participant Spending	$10.6	0.7	$3.7	0.7	$14.3	0.7
Total	$54.1	0.6	$18.5	0.7	$72.6	0.6

Personal Income Impact ($2014m)	Electric		Natural Gas		Total	
	Income	Income / $ Spending	Income	GDP / $ Spending	Income	GDP / $ Spending
Program Spending	$30.9	0.5	$10.4	0.5	$41.3	0.5
Participant Spending	$7.6	0.5	$2.7	0.5	$10.3	0.5
Total	$38.5	0.5	$13.1	0.5	$51.6	0.5

Estimating the Impact of Program Savings

EE program cost savings to businesses and consumers include the value of reduced electricity and gas consumption (including avoided transmission and distribution costs and capacity savings associated with reduced energy consumption), other fossil fuel savings, water savings and non-energy savings, such as reduced O&M costs and productivity improvements. As discussed above, these savings boost local purchasing power and increase regional competitiveness, leading to increased economic activity and employment.

To estimate their economic impact, residential cost savings are entered into REMI as a consumption reallocation increase and spread to Rhode Island counties based on population. C&I cost savings are entered as a production cost decrease and spread to Rhode Island C&I industries based on output. The savings amounts themselves are taken as lifetime benefits from the Total Resource Cost test performed for the 2014 EE Plan, net of the discount rate. These savings amounts, presented in Table 3 below, are

divided equally among measure life years, 2014 through 2027, and entered into REMI in 2014 dollars.

Table 3

ELECTRIC AND GAS PROGRAM SAVINGS BY CUSTOMER SEGMENT

($2014M)

	Electric	Gas	Total
Residential	$80.5	$29.5	$110.0
C&I	$178.4	$20.4	$198.8
Total	$258.9	$49.9	$308.8

Source: RI Energy Efficiency Program Plan for 2014, Table E-6 and G-6 (net of discount rate). Includes the value of own fuel savings, other fuel savings, water savings and non energy savings from the 2013 Avoided Cost Study. Excludes Toray Benefits.

Estimated employment impacts due to EE program savings are shown in Table 4, totaling 3,253 job years over the lifetime of the measures. This is a subset of the total employment impact of the 2014 Plan presented in Table ES-2, 3,607 job years, which includes the construction phase impacts discussed in the previous section and the negative economic impact of program and participant costs, discussed below.

Table 4

IMPACT OF 2014 ELECTRIC AND GAS PROGRAM SAVINGS - JOB YEARS (BEFORE COSTS)

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Lifetime
ELECTRIC															
Residential	31	31	30	29	28	27	26	25	24	24	23	23	22	22	363
C&I	84	119	145	165	179	188	194	198	200	201	201	201	200	198	2,474
Total	115	150	175	194	207	215	220	223	224	225	225	223	222	220	2,837
GAS															
Residential	11	11	11	11	10	10	10	9	9	9	9	9	9	8	135
C&I	10	14	17	19	20	21	22	22	23	23	23	23	23	22	281
Total	21	25	28	30	31	31	32	32	32	32	32	31	31	31	416
TOTAL															
Residential	42	42	41	40	38	37	36	34	33	32	32	31	31	30	499
C&I	94	132	162	184	199	209	216	220	223	224	224	223	222	221	2,754
Total	136	174	203	223	237	246	252	255	256	256	256	255	253	251	3,253

Table 5 summarizes the impact of lifetime cost savings on job years, GDP and income, before program and participant costs. The multipliers show impacts per dollar of savings, before costs. For example, each $1.0 million in total residential and C&I lifetime savings is estimated to create 10.5 job years. Each $1.0 of total savings creates $1.0 of GDP and raises personal income by $0.7. Note that the multipliers in Table 5 are on the dollar value of program *savings* not program *spending.*

Table 5
ELECTRIC AND GAS PROGRAM SAVINGS -- ECONOMIC BENEFITS (BEFORE COSTS)

Employment Impacts	Electric		Natural Gas		Total	
	Job Years	Job Yrs / $m Savings	Job Years	Job Yrs / $m Savings	Job Years	Job Yrs / $m Savings
Residential Savings	363	4.5	135	4.6	499	4.5
C&I Savings	2,474	13.9	281	13.8	2,754	13.9
Total	2,837	11.0	416	8.3	3,253	10.5

GDP Impact ($2014m)	Electric		Natural Gas		Total	
	GDP	GDP / $ Savings	GDP	GDP / $ Savings	GDP	GDP / $ Savings
Residential Savings	$28.9	0.4	$10.8	0.4	$39.7	0.4
C&I Savings	$247.2	1.4	$28.1	1.4	$275.3	1.4
Total	$276.1	1.1	$38.9	0.8	$315.0	1.0

Personal Income Impact ($2014m)	Electric		Natural Gas		Total	
	Income	Income / $ Savings	Income	Income / $ Savings	Income	Income / $ Savings
Residential Savings	$21.3	0.3	$8.3	0.3	$29.7	0.3
C&I Savings	$177.2	1.0	$20.0	1.0	$197.3	1.0
Total	$198.6	0.8	$28.4	0.6	$226.9	0.7

Impact of Program and Participant Costs

EE program and participant costs to residential and C&I customers have negative economic impacts, reducing the positive economic benefits described above. To estimate the negative economic impact of 2014 EEPP costs, residential program and participant costs are entered into REMI as a consumption reallocation decrease, while C&I costs are entered as a production cost increase.[6] The resulting negative economic impacts are subtracted from the positive impacts shown in Tables 2, 4, and 5, yielding the net economic benefits in Table ES-2 and reflected in the spending multipliers in Table ES-3. Detailed economic multipliers on program and participant costs, by customer segment, are provided in the "Summary and Conclusions" section below.

CHP Project Impacts

CHP projects have the same kind of economic impacts as EE programs. First, program and participant spending creates jobs in construction and other industries as the projects are planned, and equipment is purchased and installed. However, for CHP projects a large portion of total spending is often used to purchase cogeneration equipment that is produced outside of the region and has no local economic impact. Second, net lifetime energy cost savings to C&I participants lower their business costs, allowing them to sell more into competitive markets. This has a positive impact on local economic activity as these firms are able to increase output and hiring. Third, rate increases to cover the incentive payment and customer contributions to pay for the measures raise business costs, reducing the above benefits. The total economic impact of CHP projects equals the sum of the positive spending and savings impacts and the negative cost impacts.

[6] The residential and C&I costs were taken from Tables E-1 and G-1 of the 2014 EEPP and are summarized in Table 7 below.

CHP project economic benefits are estimated based on the Massachusetts CHP data presented in Table ES-4 and the Rhode Island REMI model. CHP project *spending* benefits are estimated by entering 60% of the program (incentive) and participant spending amounts shown in Table ES-4 into REMI as a 2014 exogenous increase in final demand in the construction industry. This is the portion of total CHP spending used to install cogeneration equipment at C&I facilities, based on the Massachusetts CHP data. The remaining 40% of spending is assumed to be used to purchase equipment from outside of the region, as is typical for Massachusetts CHP projects, and is not considered in the analysis.

To estimate the economic impact of CHP energy cost savings to participants, lifetime benefits from Table ES-4 are divided equally among measure life years, 2014 to 2032, and entered into REMI as a production cost decrease, in 2014 dollars. Note that these benefits are lifetime electricity and heating cost savings, net of increased natural gas and O&M costs needed to run the cogenerating equipment.

To estimate the impact of CHP project costs, customer costs from Table ES-4 are entered into REMI as a 2014 production cost increase. Incentive costs from Table ES-4 are split between the residential and C&I customer segments based on the 2014 electric EEPP split of the SBC charge between residential and C&I. The residential portion is entered as a consumption reallocation decrease while the C&I portion is entered as a production cost increase.

Results are summarized in Table 6 below. Construction spending in Table 6 equals 60% of total CHP project spending from Table ES-4, which is the percent assumed for installation of the CHP equipment. Total savings (lifetime benefits) and total costs are both taken directly from able ES-4. The job year, GDP and income multipliers are applied to these amounts to show estimated Rhode Island economic impacts from the CHP construction spending, savings and costs. These are summed to show the total economic impact that the representative Massachusetts CHP projects would have in Rhode Island, after all costs are taken into account.

Total CHP project spending is divided by the job year, GDP and income totals yielding the total spending multipliers at the bottom of the table and reproduced in Table ES-5 of the Executive Summary. Both GDP and income are in 2014 dollars and "income" is measured as personal income.

Table 6

CHP PROJECT ECONOMIC MULTIPLIERS							
CHP Project Data		Job Years/$m	Job Years	GDP/$	GDP	Income/$	Income
Construction Spending	$3,761,172	12.4	47	0.8	$3,034,363	0.6	$2,244,149
Total Savings	$12,042,883	14.1	170	1.5	$17,568,939	1.1	$12,703,018
Total Cost	$6,268,620	-6.6	-41	-0.5	-$3,506,352	-0.3	-$2,126,284
		Total	175	Total	$17,096,950	Total	$12,820,883
TOTAL SPENDING MULTIPLIERS							
		Jobs/$m	Job Years	GDP/$	GDP	Income/$	Income
Total Spending	$6,268,620	28.0	175	2.73	$17,096,950	2.0	$12,820,883

Summary and Conclusions

This study provides (1) an analysis of the economic impact of the 2014 EEPP; (2) what the economic impact of representative Massachusetts CHP projects would be in Rhode

Island; (3) updated spending multipliers for use in evaluating future EE plans and CHP projects in Rhode Island; and (4) a description of how each component of the total EE program and CHP economic impact is estimated.

While the updated spending multipliers in Table ES-3 and ES-5 are appropriate for evaluating the expected economic impact of EE programs and CHP projects with similar benefit cost ratios and program offerings to the 2014 EEPP and representative Massachusetts CHP project data, respectively, these factors could change over time, reducing the accuracy of the total spending multipliers. To avoid this problem, it is preferable to use separate multipliers for each of component of the total EE program and CHP economic impact and add them up. This will account for changes in benefit cost ratios and program offerings over time that could result from changes in energy prices, technology and markets.

For CHP projects, multipliers for each component of the total economic impact are shown in Table 6 above. For the 2014 EEPP, these component multipliers are provided below in Table 7. The components are program spending, participant spending, residential benefits, C&I benefits, residential costs and C&I costs, as shown under the heading "EE Program Component." The dollar value of each of these components is shown under the heading "2014 EE Plan ($m)" while corresponding job year and GDP multipliers, by EE program type (electric and gas), are shown to the right of these dollar amounts. Multiply the dollar amount for each EE program component by the corresponding job year and GDP multiplier to obtain job year and GDP impacts for each component. Add up the resulting job year and GDP impacts on each of these components to get total EE program job year and GDP impacts.[7] Note that total EE spending may be divided by these totals for comparison to the spending multipliers shown in Table ES-3 of the Executive Summary.

Table 7
Economic Impact Multipliers by EE Plan Component

EE Program Component	2014 EE Plan ($m)		Job Years/$ Million		GDP / $	
	Electric	Gas	Electric	Gas	Electric	Gas
Program Spending	$68.5	$22.4	9.1	9.5	0.6	0.7
Participant Spending	$16.1	$5.4	9.6	10.1	0.7	0.7
Residential Benefits	$80.5	$29.5	4.5	4.6	0.4	0.4
C&I Benefits	$178.4	$20.4	13.9	13.8	1.4	1.4
Residential Costs	$35.4	$13.8	-5.4	-5.4	-0.4	-0.4
C&I Costs	$49.3	$14.1	-6.7	-6.7	-0.6	-0.6

Note: Residential includes income eligible program participants.

Although use of the detailed multipliers in Tables 6 and 7 will take into account short-term changes in energy prices, benefit cost ratios and program offerings, even these estimates should be updated at least every 3-5 years. Multipliers on benefits, costs and spending will change gradually over time with changes in the mix of Rhode Island industries and the responsiveness of businesses and consumers to price changes.

[7] Note that doing this yields the total job year and GDP impacts shown in Table ES-2.

Division 2-2

Request:

Referring to the response to Division 1-2, please provide a schedule showing an itemized breakdown of the total negative "Gas $ benefits" and negative "O&M benefits" shown in the chart.

a. Please identify each line item, including a footnoted explanation as necessary to assure that the nature and content of the line item can be easily understood.

b. To the extent any individual line item spans over multiple years, please also provide a supplemental schedule that shows the cost incurrence for each year of the analysis.

c. Does the negative "Gas $ benefits" line in the chart include the cost of any incremental interstate pipeline capacity? If so please include this cost separately in the itemization. If not, please explain why not.

Response:

a. The negative "Gas $ Benefits" were calculated based on the net increase in gas use (proposed gas use post-CHP minus historic gas use pre-CHP) at the Navy site using an estimated hourly performance model for the proposed CHP system, provided by BQ Energy LLC. The modeled increase in gas use is 301,675 MMBTU per year during the winter season and is multiplied by the winter heat value for gas from the avoided cost table – column "NG - C&I Gas Heat" in the excerpt from the avoided cost table below – using the 20-year cumulative value of $264.16, to arrive at a net present value (NPV) of negative $79,690,920. The avoided cost table values are specific to Rhode Island and derive from the Avoided Energy Supply Costs in New England 2015 Study (AESC Study), which is the source of avoided costs used in the Rhode Island Benefit Cost Test (RI Test), as approved in Docket No. 4755, which indicates "CHP Benefits are assessed consistently with the RI Test and benefits".[1] Note that the $264.16 value for winter gas includes the value for CO2, as approved in the RI Test in Docket No. 4755.

   The project team estimated an annual operation and maintenance (O&M) cost of $687,500, which was multiplied by the 20-year cumulative NPV of Non Resource Annual value of $19.47 (also shown in the excerpt from the avoided cost table) to arrive at a NPV of negative $13,385,822.

[1] Docket No. 4755, Attachment 4, page 12 of 19.

Division 2-2, page 2

		Year 1 Avoided Cost Data - In Nominal Dollars							
		Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
RI	2018	Fuel Oil - Com #2 Oil ($ per MMBtu)		Fuel Oil - Com #4 Oil ($ per MMBtu)		NG - C&I Gas Heat ($ per MMBtu)		Non-Resource Annual	
1	2018	$20.67	$20.64	$20.54	$20.51	$11.85	$11.83	$1.000	$0.999
2	2019	$22.35	$42.90	$22.21	$42.63	$12.42	$24.20	$1.000	$1.995
3	2020	$24.00	$66.74	$23.83	$66.30	$12.86	$36.97	$1.000	$2.988
4	2021	$25.62	$92.12	$25.43	$91.49	$13.28	$50.13	$1.000	$3.979
5	2022	$27.26	$119.05	$27.07	$118.23	$13.20	$63.17	$1.000	$4.966
6	2023	$28.77	$147.40	$28.55	$146.36	$13.56	$76.53	$1.000	$5.952
7	2024	$29.04	$175.93	$28.80	$174.67	$13.86	$90.15	$1.000	$6.934
8	2025	$29.50	$204.84	$29.26	$203.34	$13.98	$103.84	$1.000	$7.914
9	2026	$30.11	$234.28	$29.88	$232.54	$13.81	$117.34	$1.000	$8.892
10	2027	$30.62	$264.12	$30.38	$262.15	$13.71	$130.71	$1.000	$9.866
11	2028	$30.94	$294.19	$30.69	$291.98	$13.76	$144.08	$1.000	$10.838
12	2029	$31.43	$324.66	$31.18	$322.20	$13.81	$157.47	$1.000	$11.808
13	2030	$31.77	$355.38	$31.52	$352.68	$13.81	$170.82	$1.000	$12.775
14	2031	$32.54	$386.76	$32.28	$383.81	$13.76	$184.09	$1.000	$13.739
15	2032	$33.15	$418.63	$32.88	$415.43	$13.82	$197.38	$1.000	$14.701
16	2033	$33.76	$451.01	$33.49	$447.55	$13.88	$210.70	$1.000	$15.660
17	2034	$34.40	$483.92	$34.12	$480.19	$13.94	$224.03	$1.000	$16.616
18	2035	$35.05	$517.35	$34.76	$513.35	$14.00	$237.39	$1.000	$17.570
19	2036	$35.72	$551.33	$35.42	$547.05	$14.06	$250.76	$1.000	$18.522
20	2037	$36.40	$585.87	$36.10	$581.30	$14.12	$264.16	$1.000	$19.470
21	2038	$37.10	$620.97	$36.79	$616.11	$14.18	$277.58	$1.000	$20.417
22	2039	$37.82	$656.66	$37.50	$651.50	$14.25	$291.03	$1.000	$21.360
23	2040	$38.56	$692.95	$38.23	$687.47	$14.31	$304.49	$1.000	$22.301
24	2041	$39.31	$729.85	$38.97	$724.05	$14.37	$317.98	$1.000	$23.240
25	2042	$40.09	$767.37	$39.74	$761.25	$14.43	$331.49	$1.000	$24.176

b. The avoided cost table above shows both annual and cumulative dollar values for measure lives from 1 to 25 years, where the Navy CHP benefit-cost (BC) calculation uses the cumulative value at 20 years. The Navy CHP was assigned a 20-year measure life based on being industrial hardware that will be maintained annually (reflected in the O&M costs). The reduced operating hours of 4,500 hours per year is likely to extend the apparent calendar measure life of the installed unit beyond 20 years (this type of equipment in similar installations often runs 8,000+ hours per year), but no additional years of measure life were included in the BC calculation.

Division 2-2, page 3

c. The "Gas $ Benefits" does not include incremental in-state pipeline capacity for two reasons. First, the "Gas $ Benefits" are consistent with the 2015 AESC study. Second, as stated in the Company's response to Data Request Division 2-4, the Company will not be purchasing additional interstate pipeline capacity to assure firm deliveries to the project.

Division 2-3

Request:

Has the Company performed any analysis of the impact on the capacity of the gas Distribution system in the area of the project during winter months once the project has become operational? If so, please provide a copy. If not, please explain why it was not done in advance and explain the impact in response to this question.

Response:

The Company did perform an analysis of the impact on the capacity of the gas distribution system in the area of the project during winter months. The results of that analysis required that a distribution system reinforcement project be constructed to offset the impact on distribution system capacity of the project during winter months (i.e., 3,000 feet of 12-inch 99 psig main on Green End Avenue, Middletown).

Attachment DIV 2-3 provides a copy of the analysis record.

GCR Engineer Summary to File

Engineer Incident ID:	400053762	Sub #:	1
Work Order #:		Gas On Date:	3/7/2017

Customer:	BQ Energy LLC
Address:	0 Simonpietri Dr
City, State:	Newport , RI

Date/Time Received:	3/2/2017 2:21:00 PM
Date/Time Approved:	3/31/2017 2:45:00 PM
Engineer Name:	B Flynn

Sales Status:	Implementation		
Sales Rep:	Thomas Dion		
Orginator:	Industrial	Request Type:	New Firm
GPM:	720354	Sales Type:	New Construct

Model Name:	RI Rhode Island		
MAOP:	99 psig	Node Name Low Point:	NPRTM79621059P0
Customer Node Name:	MDTTP73868606P099	Node Pressure Low Point:	5.45 " wc
Node Existing Pressure:	67.65 psig	Node Name Low Point w/Load:	NPRTM79621059P0
Node Pressure w/Load:	55.07 psig	Node Pressure Low Point w/Load:	1.8 " wc

1st Total Load (Dth/hr):	126	1st Rate:	
2nd Total Load (Dth/hr):		2nd Rate:	
3rd Total Load (Dth/hr):		3rd Rate:	
Diverisified Load (Dth):	126.0		
Emergency Load (Dth):			
Firm Load Added (Dth):	126.0	TC Load Added (Dth):	

ENGINEERING COMMENTS

Non firm Boiler Plant will not operate when CHP system is operating.

ONYX WORK NOTES

BF 3/31/2017
Gas Operations Engineering approves the proposed load of 126,000 CFH contingent upon:
1)Growth Reinforcement: Due to the integrity of the 99psig, 35psig, and LP systems in the surrounding locations of this request, the installation of approx. 3,000 ft of 12 in WS 99psig main on Green End Avenue in Middletown RI will be an adequate reinforcement keep all pressures above system minimum and allow the customer to achieve its desired gas capacity request.

GCR Engineer Summary to File

2)Growth Reinforcement: There is a 12 in WS 99psig stub on the intersection of Green End Ave @ Compton View Dr which will be extended with 12 in WS 99psig approx. 3,000 ft parallel with the existing 8 in WS 99psig on Green End Ave to the 12 in WS 99psig stub on the corner of Green End Ave and Aquidneck Ave.
3)After this reinforcement is complete, the installation of up to 100 ft of 8 in WS 99psig service off of the existing 12 in WS 99psig main will be adequate to serve the Boiler Plant.

Please note that these lengths of pipe are approximate and will need to be measured from one 12 in WS 99psig stub to the next 12 in WS 99psig stub on Green End Ave.

BF 3/27/2017

Please attach mapping with location. Opportunity's mapping says 32 mechanic st Woonsocket. No streets in map can be located in smallworld.

Reinf Reqd	☑	MainExt Reqd	☐	Reinf Type	Sales	MainExt Type	

Division 2-4

Request:

Has the Company analyzed whether the incremental gas demand arising from the operation of the CHP unit during the winter will result in a need for the Company to purchase more interstate pipeline capacity to assure firm deliveries to the project during peak winter demand? If so, please provide a copy. If not, please explain why it was not done in advance and provide a response to the question about increased capacity costs. Please also provide an estimate of the incremental cost of pipeline capacity that would result from the incremental gas demand during peak winter season.

Response:

The Company will not be purchasing additional interstate pipeline capacity to assure firm deliveries to the project. After receiving this data request, the Company analyzed whether additional interstate pipeline capacity would be necessary to provide firm service to the project, and the Company determined that no such additional capacity would be necessary, so long as the Navy agreed to cease CHP equipment operation on days on which weather conditions are colder than 52 heating degree days (HDD) (an average of 3.4 days per year). A copy of this analysis is provided as Attachment DIV 2-4. The Company currently is negotiating with the Navy and is optimistic that it will agree to this requirement. If the Navy and the Company are not able to reach agreement on this requirement, then the Navy and the Company will explore other options for the project, but in no event will the Company purchase additional interstate pipeline capacity for the project. As such, the Company does not estimate any incremental costs for pipeline capacity as a result of the project.

4755-DIV 2-4 Attachment

Temperature (HDD)	Sendout Forecast for Portsmouth Take Station (Dth/Day) Pipeline Contract = 22,089									
	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
55	19,797	19,921	20,031	20,029	20,079	20,280	20,105	20,473	20,444	20,534
54	19,473	19,594	19,703	19,700	19,750	19,948	19,775	20,138	20,109	20,197
53	19,146	19,266	19,372	19,370	19,419	19,613	19,443	19,800	19,771	19,858
52	18,820	18,937	19,042	19,039	19,087	19,279	19,112	19,462	19,434	19,520
51	18,493	18,608	18,712	18,709	18,756	18,944	18,780	19,124	19,097	19,181
50	18,166	18,280	18,381	18,379	18,425	18,610	18,448	18,787	18,760	18,842

Temperature (HDD)	Sendout Forecast for Portsmouth Take Station with Navy CHP Load (Dth/Day)									
	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
55	22,317	22,441	22,551	22,549	22,599	22,800	22,625	22,993	22,964	23,054
54	21,993	22,114	22,223	22,220	22,270	22,468	22,295	22,658	22,629	22,717
53	21,666	21,786	21,892	21,890	21,939	22,133	21,963	22,320	22,291	22,378
52	21,340	21,457	21,562	21,559	21,607	21,799	21,632	21,982	21,954	22,040
51	21,013	21,128	21,232	21,229	21,276	21,464	21,300	21,644	21,617	21,701
50	20,686	20,800	20,901	20,899	20,945	21,130	20,968	21,307	21,280	21,362

Division 2-5

Request:

Has the Company analyzed whether the incremental gas demand arising from the operation of the CHP unit during the winter will result in an increase in the cost of maintaining system pressure in any area of the Company's distribution system? If so, please provide a copy. If not, please explain why it was not done in advance and provide a response that addresses the question about system pressure costs. Please also provide an estimate of any incremental system pressure costs that would result from the incremental gas demand during peak winter season.

Response:

The Company considered the impact of the operation of the CHP unit during the winter on system pressures in all areas of the gas distribution system. As a result of the distribution system reinforcement project described in the Company's response to Division 2-3, the Company does not anticipate any incremental costs of maintaining system pressure resulting from the incremental CHP gas demand during the winter.

Division 2-6

Request:

Does the Navy have any distributed generation wind or solar projects planned for installation at the Navy's premises that would result in the electricity being produced by the solar facilities being consumed by the Navy on site? If so,

a. please identify the project(s), where they will be located and note whether the electric load that would be served by the CHP unit would also be served by the solar facilities.

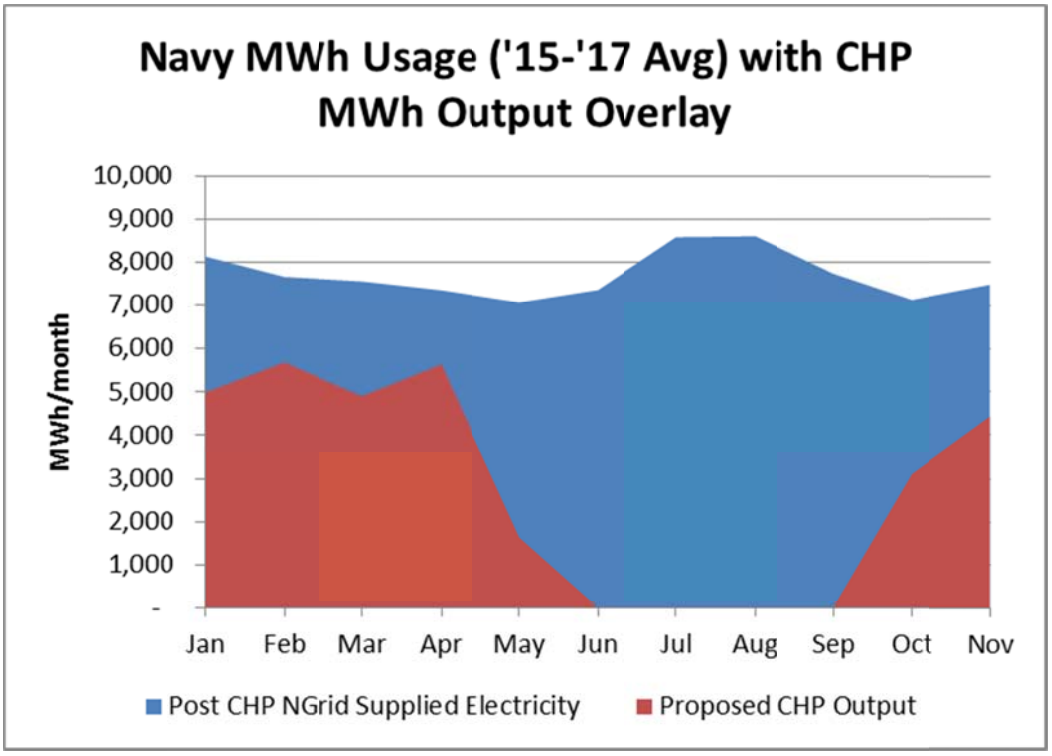
b. Would consumption from the wind or solar facilities displace any electric production from the CHP unit at any times during the year? If so, please explain. If not, explain why not. If so, did the analysis of the savings achievable from the CHP unit take into account kilowatt-hour production that would be consumed on site and potentially displace electric production from the CHP unit?

Response:

The Navy is working with a solar project developer, who is installing three solar arrays totaling 21 MW's of nameplate capacity on the Navy's property. The new 21 MW of solar array will not be behind Navy-billed meters but will interconnect directly onto the Company's electric grid with its own production meter(s). The solar electricity will be sold to customers as the developer sees fit, outside of the Company's control. Therefore, the solar electricity will not be interactive with the Navy's electric load being delivered by the proposed CHP system.

The Navy has considered other potential solar and wind projects on its campus in the past three years. However, the Company understands that the Navy determined that the projects were not viable when they were being considered. Currently, the Navy has 621 kW of nameplate solar capacity installed on its campus. This solar capacity is interconnected with the Company's electric service, and the existing solar capacity was included in the CHP energy modeling calculations. The graph below shows historic electric usage and proposed CHP output, and shows that there is still a significant amount of electricity consumption that could be reduced by additional energy efficiency projects or met with other distributed generation projects. As with all customers, the Company will continue working with the Navy to consider and implement energy efficiency and distributed generation projects in relation to the best available historic or forecast load circumstance at the time of project consideration.

Division 2-6, page 2



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Division 2-7

Request:

Does the Navy have any plans for any other renewable or other distributed generation on site that might displace consumption from the CHP unit?

Response:

Please see the Company's response to Division 2-6.

Division 2-8

Request:

Please identify the assumed efficiency of the CHP unit. Please provide copies of any back up information supporting the efficiency assumption.

Response:

The overall efficiency of the CHP unit was calculated using a custom hourly performance analysis for the proposed equipment for a typical weather year, where useful thermal and electrical output was divided by total higher heating value (HHV) gas input to the CHP. The monthly totals for energy inputs and outputs, as well as efficiencies, are shown below.

Navy CHP Monthly Energy & Efficiency Summary

	Delivered Electricity (MWh)	Delivered Electricity (MMBTU)	Delivered Steam (MMBTU)	Fuel Usage (MMBTU)	Electrical Efficiency	Thermal Efficiency	Monthly Overall CHP Efficiency
Jan	4,992	17,033	20,014	58,981	28.9%	33.9%	62.8%
Feb	5,685	19,398	22,806	67,040	28.9%	34.0%	63.0%
Mar	4,906	16,740	19,404	58,102	28.8%	33.4%	62.2%
Apr	5,639	19,240	19,385	67,302	28.6%	28.8%	57.4%
May	1,634	5,577	3,018	19,656	28.4%	15.4%	43.7%
Jun	-	-	-	0			
Jul	-	-	-	0			
Aug	-	-	-	0			
Sep	-	-	-	0			
Oct	3,104	10,592	6,663	37,263	28.4%	17.9%	46.3%
Nov	4,432	15,122	14,548	53,078	28.5%	27.4%	55.9%
Dec	5,762	19,661	20,429	68,937	28.5%	29.6%	58.2%
Yearly Total	36,156	123,363	126,267	430,359			

Delivered Electricity + Steam MMBTU/yr	249,630	
Fuel consumption MMBTU/yr	430,359	
58.0%	**CHP yearly operating efficiency**	

The above estimates are based on a Solar Taurus 70 Gas Turbine Generator with Rentech Heat Recovery Steam Generator as described in the Minimum Requirements Document associated with the Energy Efficiency project application, and as excerpted in the following:

Division 2-8, page 2

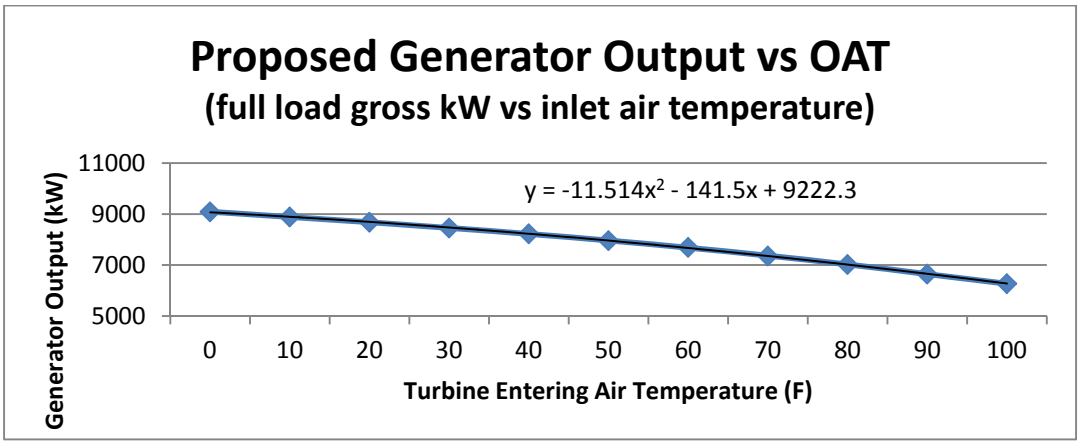
Milestone 2a. Installation Completion

1. Install one **7,965 kWe** Gas turbine generator (GTG) at ISO rating; Solar Taurus 70 model or equal.
2. Install one HRSG with a natural gas fired duct burner installed on the inlet, Rentech GTB-XFL-1205 or equal. The GTG exhaust to steam efficiency is expected be 97% or higher. The efficiency of the duct burner is estimated to be 96%. When bolted to the outlet of the GTG, the HRSG & duct burner system shall be capable of delivering 60,000 lbs/hr of 150 psig steam at 32.1 MMBTU/hr of fuel input.
3. GTG unit shall meet the following criteria derived from the product selection sheets. Performance is based on 60F degree inlet air temperature at sea level, 4" inlet & 10" exhaust pressure losses, 150 psig steam, with 228F degree feedwater:
    a. electric output at the generator terminals: **7,692 kW**
    b. thermal output, **32.0 kpph**
    c. overall efficiency: 67% at full load based on 86.9 MMBTUh of fuel input (using HHV)
    d. GTG gross HHV performance at 60F as follows:

	100%	75%	50%
Electrical output	7,692 kW	5,769 kW	3,846 kW
Fuel input (HHV)	86.9 MMBTUh	71.4 MMBTUh	57.3 MMBTUh
HRSG steam (GTG)	32.0 kpph	25.5 kpph	20.5 kpph
Electrical efficiency	30.2%	27%	23%
Thermal efficiency	36.8%	36%	35%

    e. Generator gross kW vs Outdoor Air Temperature

Division 2-8, page 3



f. Parasitic loads: estimated at 213 kW during full-load operation; inclusive of gas compressor, all pumps and fans; accounting for expected added CHP parasitic equipment loading at these conditions and deducting diminished boiler loads, as applicable.

The Company will attach the Minimum Requirements Document in Data Request Division 5-11.

Division 2-9

Request:

Referring to the response to PUC 1-1, please identify the "unique elements of the Navy project" upon which the $1,000 per kW was negotiated.

Response:

In setting the incentive, the Company considered proposed system efficiency, 5% site efficiency through additional measures, the operation hours, and a prudent use of funds that would incent the project to occur.

Beginning in November 2016, the Navy proposed to install a 7,000 kW generator to operate all year round. The Navy and the developer requested that the Company estimate the incentive early in the process so the Navy could run its financial models. The Company's analyses reasoned with the "proper design caveats" (achieving the 55% Overall Efficiency metric, etc.) that the customer would most likely meet or exceed the $1000/kW threshold and that the Navy could continue this minimum incentive level. Therefore, the Company estimated a $7 million incentive for the project.

One year later, the Navy's team informed the Company that the design of the system had changed. The size of the unit increased from 7.0 MW to 7.965 MW, and operation would likely be October through April instead of year-round. It is unique that the project will not create summer kW super peak savings like a typical year-round operational CHP.

The incentive is based on 7MW to reduce for parasitic load and non-peak conditions. The 7 MW net generator meets the 55% + System efficiency metric, qualifying it for $900/kW. The Navy also qualified for a higher tiered incentive by reducing site energy by 5%, which, according to the 2018 EE Plan, can increase the incentive "up to $1125/kW" after completing additional energy efficient projects over the past 12 months. The Company determined that it could obtain these energy efficiency savings at the initial offering of $1000/kW for 7 MW without jeopardizing the project financial requirements.

Division 2-10

Request:

Please provide a copy of the projected annual load and production profile of the CHP project, upon which the annual and lifetime kWh savings shown in the chart in the response to PUC 1-2 were determined.

Response:

The following chart and graphs below show historic site electric loads and proposed CHP generation based on a typical winter heating season. Although there have been minor changes in total electric consumption over time due to changes in site utilization and energy efficiency projects, the overall electric usage at the site has been relatively stable, with no known significant changes expected. Therefore, the continuation of a stable profile was used as the best information at the time of project consideration.

Navy Electricity Profile and Load Fraction, Pre/Post CHP Installation

	Pre-CHP Electricity Use ('15-'17 Avg)	Proposed CHP Output	Post CHP NGrid Supplied Electricity	Electric Load Fraction Served by CHP
	MWh/month	MWh/month	MWh/month	
Jan	8,137	4,992	3,145	61.4%
Feb	7,664	5,685	1,978	74.2%
Mar	7,557	4,906	2,651	64.9%
Apr	7,351	5,639	1,712	76.7%
May	7,065	1,634	5,431	23.1%
Jun	7,358	-	7,358	0.0%
Jul	8,584	-	8,584	0.0%
Aug	8,606	-	8,606	0.0%
Sep	7,740	-	7,740	0.0%
Oct	7,127	3,104	4,023	43.6%
Nov	7,481	4,432	3,049	59.2%
Dec	7,345	5,762	1,583	78.5%
Yearly Totals	92,015	36,156	55,860	39.3%

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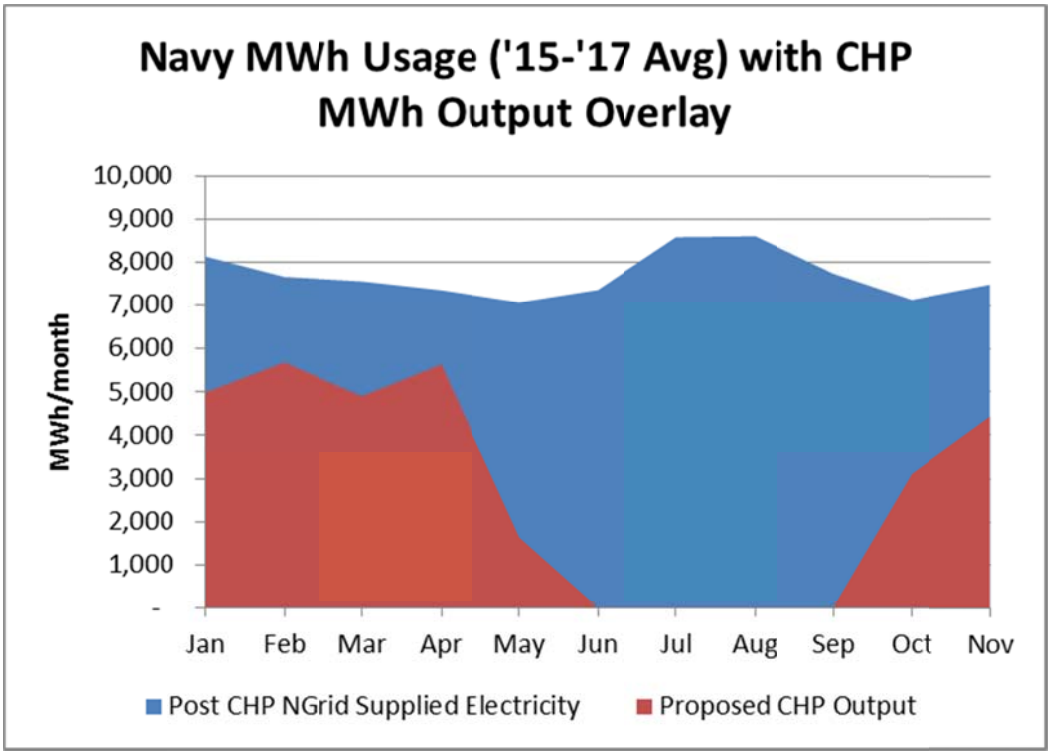

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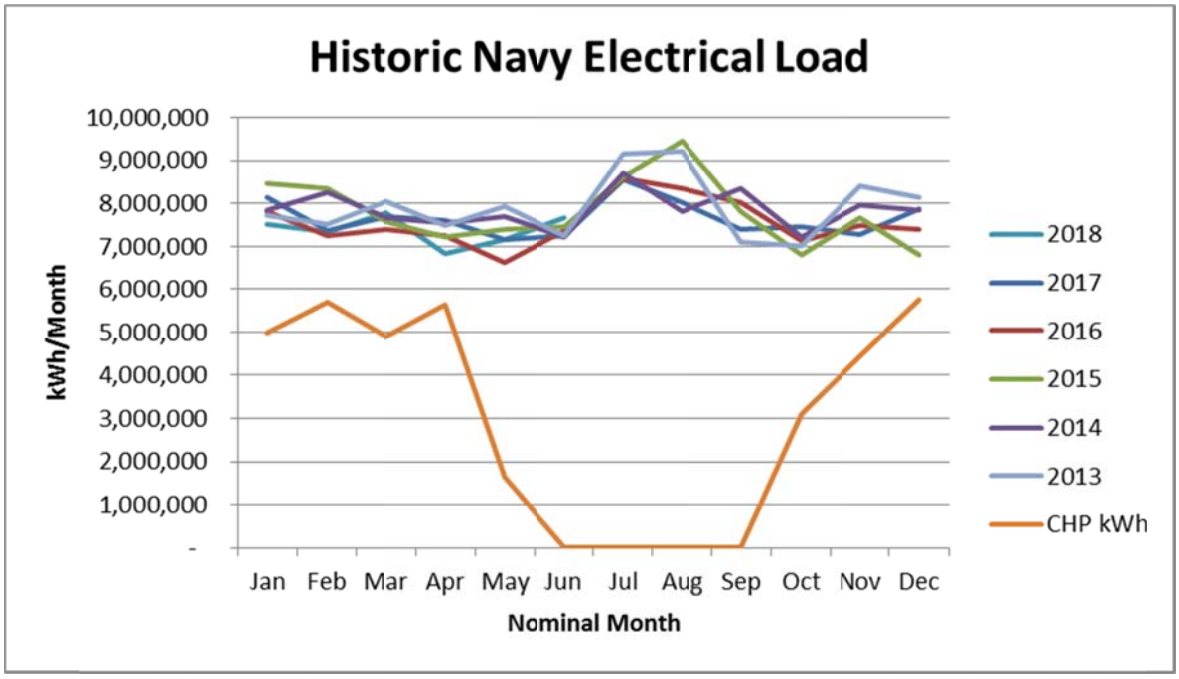
Division 2-11

Request:

Please provide a copy of the historical electric load profile of the Navy for the past five years at the site that will be served electrically by the proposed CHP unit in the future.

Response:

The following graph shows the historic kWh/month usage at the Navy and the expected generation from the proposed CHP system:



The Company's billing system dates do not always align with calendar months. This is why the graph above includes the 'Nominal Month' x-axis label.

The chart below shows historic usage information.

Division 2-11, page 2

Acct #:			XXXXX-XXXXX			
	Billing Period		Actual	Actual	Billed	Actual / Billed
Month/Year	From	To	kVA	kW	kW	kWh
(a)	(b)	(c)	(d)	(e)	(f)	(g)
201301	11/29/2012	1/1/2013	14,472.0	14,076.0	14,553.0	8,479,374
201302	1/2/2013	1/30/2013	15,556.0	15,120.0	15,120.0	7,712,852
201303	1/31/2013	2/28/2013	15,028.0	14,672.0	14,672.0	7,510,738
201304	3/1/2013	3/31/2013	15,144.0	14,640.0	14,640.0	8,041,260
201305	4/1/2013	4/30/2013	14,672.0	14,210.0	14,553.0	7,494,792
201306	5/1/2013	6/2/2013	15,776.0	15,012.0	15,012.0	7,925,177
201307	6/2/2013	6/30/2013	18,840.0	17,720.0	17,720.0	7,237,554
201308	6/30/2013	7/31/2013	19,864.0	19,412.0	19,412.0	9,153,649
201309	7/31/2013	9/2/2013	18,900.0	18,376.0	18,376.0	9,215,416
201310	9/2/2013	9/30/2013	18,380.0	17,716.0	17,716.0	7,098,451
201311	9/30/2013	10/29/2013	16,456.0	15,504.0	15,504.0	6,996,975
201312	10/29/2013	12/1/2013	15,000.0	14,656.0	14,656.0	8,411,014
201401	12/1/2013	1/1/2014	14,976.0	14,656.0	14,656.0	8,144,882
201402	1/1/2014	1/30/2014	15,516.0	15,128.0	15,128.0	7,846,971
201403	1/30/2014	3/2/2014	15,052.0	14,764.0	14,764.0	8,270,521
201404	3/2/2014	3/31/2014	15,260.0	14,832.0	14,832.0	7,665,739
201405	3/31/2014	4/30/2014	14,108.0	13,740.0	14,559.0	7,535,768
201406	4/30/2014	6/2/2014	14,908.0	14,248.0	14,559.0	7,689,309
201407	6/2/2014	6/30/2014	17,464.0	16,496.0	16,496.0	7,205,338
201408	6/30/2014	7/31/2014	17,432.0	16,956.0	16,956.0	8,716,806
201409	7/31/2014	8/28/2014	17,456.0	16,940.0	16,940.0	7,799,303
201410	8/28/2014	9/29/2014	18,136.0	17,696.0	17,696.0	8,355,582
201411	9/29/2014	10/29/2014	14,956.0	14,356.0	14,356.0	7,222,790
201412	10/29/2014	12/1/2014	14,052.0	13,776.0	13,776.0	7,972,178
201501	12/1/2014	1/1/2015	14,756.0	14,436.0	14,436.0	7,855,292
201502	1/1/2015	2/1/2015	15,872.0	15,556.0	15,556.0	8,460,731
201503	2/1/2015	3/2/2015	15,352.0	15,068.0	15,068.0	8,350,790
201504	3/2/2015	3/31/2015	14,556.0	14,252.0	14,252.0	7,582,175
201505	3/31/2015	4/30/2015	13,356.0	13,068.0	13,272.0	7,218,341
201506	4/30/2015	6/1/2015	13,984.0	13,532.0	13,532.0	7,395,635
201507	6/1/2015	6/30/2015	17,544.0	16,404.0	16,404.0	7,452,107
201508	6/30/2015	7/30/2015	19,532.0	17,776.0	17,776.0	8,613,559
201509	7/30/2015	8/31/2015	18,672.0	17,748.0	17,748.0	9,439,100
201510	8/31/2015	9/29/2015	17,792.0	17,436.0	17,436.0	7,803,080
201511	9/29/2015	10/28/2015	15,180.0	15,064.0	15,064.0	6,793,269
201512	10/28/2015	11/30/2015	14,028.0	13,608.0	13,608.0	7,676,826

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Acct #:			XXXXX-XXXXX			
	Billing Period		Actual	Actual	Billed	Actual / Billed
Month/Year	From	To	kVA	kW	kW	kWh
(a)	(b)	(c)	(d)	(e)	(f)	(g)
201601	11/30/2015	12/30/2015	12,844.0	12,616.0	13,332.0	6,789,040
201602	12/30/2015	1/31/2016	14,564.0	14,328.0	14,328.0	7,809,980
201603	1/31/2016	2/29/2016	14,288.0	14,064.0	14,064.0	7,262,481
201604	2/29/2016	3/31/2016	13,664.0	13,420.0	13,420.0	7,403,123
201605	3/31/2016	5/1/2016	13,648.0	13,460.0	13,460.0	7,240,501
201606	5/1/2016	5/31/2016	13,632.0	13,272.0	13,332.0	6,628,934
201607	5/31/2016	6/30/2016	15,404.0	14,884.0	14,884.0	7,365,402
201608	6/30/2016	8/1/2016	17,572.0	16,764.0	16,764.0	8,586,615
201609	8/1/2016	8/30/2016	17,940.0	17,136.0	17,136.0	8,346,693
201610	8/30/2016	9/29/2016	17,640.0	16,860.0	16,860.0	8,014,090
201611	9/29/2016	10/30/2016	14,600.0	14,124.0	14,124.0	7,128,077
201612	10/30/2016	11/30/2016	13,860.0	13,252.0	13,252.0	7,477,819
201701	11/30/2016	12/29/2016	14,884.0	14,700.0	14,700.0	7,383,213
201702	12/29/2016	1/30/2017	14,496.0	14,320.0	14,320.0	8,140,311
201703	1/30/2017	2/28/2017	13,672.0	13,472.0	13,472.0	7,377,473
201704	2/28/2017	3/30/2017	14,128.0	13,952.0	13,952.0	7,685,642
201705	3/30/2017	5/1/2017	13,372.0	13,188.0	13,188.0	7,594,882
201706	5/1/2017	5/31/2017	16,824.0	16,000.0	16,000.0	7,171,257
201707	5/31/2017	6/29/2017	16,960.0	16,212.0	16,212.0	7,257,070
201708	6/29/2017	7/31/2017	18,028.0	16,516.0	16,516.0	8,552,245
201709	7/31/2017	8/30/2017	16,600.0	15,932.0	15,932.0	8,032,446
201710	8/30/2017	9/28/2017	17,420.0	16,440.0	16,440.0	7,401,850
201711	9/28/2017	10/30/2017	14,632.0	14,128.0	14,128.0	7,460,228
201712	10/30/2017	11/30/2017	13,752.0	13,332.0	13,332.0	7,288,275
201801	11/30/2017	1/1/2018	13,788.0	13,556.0	13,556.0	7,862,830
201802	1/1/2018	1/30/2018	13,868.0	13,684.0	13,684.0	7,527,314
201803	1/30/2018	2/28/2018	13,580.0	13,412.0	13,412.0	7,337,240
201804	2/28/2018	4/1/2018	13,404.0	13,228.0	13,228.0	7,795,928
201805	4/1/2018	4/30/2018	12,932.0	12,716.0	12,716.0	6,827,052
201806	4/30/2018	5/31/2018	14,128.0	13,676.0	13,676.0	7,169,130
201807	5/31/2018	7/1/2018	16,260.0	15,456.0	15,456.0	7,656,222

Division 2-12

Request:

Please provide a schedule showing how the "Oil $ benefits" were calculated, as shown in the chart in response to Division 1-2, with a reasonable explanation of the assumptions used in the calculation.

Response:

The following response refers to values in the 2018 RI EEPP avoided cost table; the below excerpt of relevant columns from the table is provided for easy reference:

		Year 1 Avoided Cost Data - In Nominal Dollars							
		Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
RI	2018	Fuel Oil - Com #2 Oil ($ per MMBtu)		Fuel Oil - Com #4 Oil ($ per MMBtu)		NG - C&I Gas Heat ($ per MMBtu)		Non-Resource Annual	
1	2018	$20.67	$20.64	$20.54	$20.51	$11.85	$11.83	$1.000	$0.999
2	2019	$22.35	$42.90	$22.21	$42.63	$12.42	$24.20	$1.000	$1.995
3	2020	$24.00	$66.74	$23.83	$66.30	$12.86	$36.97	$1.000	$2.988
4	2021	$25.62	$92.12	$25.43	$91.49	$13.28	$50.13	$1.000	$3.979
5	2022	$27.26	$119.05	$27.07	$118.23	$13.20	$63.17	$1.000	$4.966
6	2023	$28.77	$147.40	$28.55	$146.36	$13.56	$76.53	$1.000	$5.952
7	2024	$29.04	$175.93	$28.80	$174.67	$13.86	$90.15	$1.000	$6.934
8	2025	$29.50	$204.84	$29.26	$203.34	$13.98	$103.84	$1.000	$7.914
9	2026	$30.11	$234.28	$29.88	$232.54	$13.81	$117.34	$1.000	$8.892
10	2027	$30.62	$264.12	$30.38	$262.15	$13.71	$130.71	$1.000	$9.866
11	2028	$30.94	$294.19	$30.69	$291.98	$13.76	$144.08	$1.000	$10.838
12	2029	$31.43	$324.66	$31.18	$322.20	$13.81	$157.47	$1.000	$11.808
13	2030	$31.77	$355.38	$31.52	$352.68	$13.81	$170.82	$1.000	$12.775
14	2031	$32.54	$386.76	$32.28	$383.81	$13.76	$184.09	$1.000	$13.739
15	2032	$33.15	$418.63	$32.88	$415.43	$13.82	$197.38	$1.000	$14.701
16	2033	$33.76	$451.01	$33.49	$447.55	$13.88	$210.70	$1.000	$15.660
17	2034	$34.40	$483.92	$34.12	$480.19	$13.94	$224.03	$1.000	$16.616
18	2035	$35.05	$517.35	$34.76	$513.35	$14.00	$237.39	$1.000	$17.570
19	2036	$35.72	$551.33	$35.42	$547.05	$14.06	$250.76	$1.000	$18.522
20	2037	$36.40	$585.87	$36.10	$581.30	$14.12	$264.16	$1.000	$19.470
21	2038	$37.10	$620.97	$36.79	$616.11	$14.18	$277.58	$1.000	$20.417
22	2039	$37.82	$656.66	$37.50	$651.50	$14.25	$291.03	$1.000	$21.360
23	2040	$38.56	$692.95	$38.23	$687.47	$14.31	$304.49	$1.000	$22.301
24	2041	$39.31	$729.85	$38.97	$724.05	$14.37	$317.98	$1.000	$23.240
25	2042	$40.09	$767.37	$39.74	$761.25	$14.43	$331.49	$1.000	$24.176

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The Oil $ benefits were calculated based on the reduction in oil use at the Navy site using an estimated hourly performance model for the proposed CHP system. The Navy historically has used #4 and #2 oil to generate steam for heating below the interruptible gas curtailment temperature. At the time of the project review (winter '17-18), the most recently available two years of oil usage ('15-16 & '16-17) were averaged to arrive at forecast oil savings.

Oil:		
#4 oil savings	21,594	MMBTU/yr
#2 oil savings	5,399	MMBTU/yr
Total oil savings	26,993	MMBTU/yr

The oil savings values were multiplied by the appropriate 20-year cumulative oil $ values from the avoided cost table to arrive at a net present value savings of $15,715,629. Note that the oil values shown in the avoided cost table excerpt include the value for non-embedded greenhouse gas emissions as approved in the RI Test in Docket 4755.

	Oil Benefits	
	#4 oil savings MMBtu/yr	#2 oil savings MMBtu/yr
	21,594	5,399
Unit dollar value (energy values from avoided cost table using 20 yr meas life)	$ 581.30	$ 585.87
Total $ Values	$ 12,552,771	$ 3,162,859
Sum of Lifetime oil NPV		$ 15,715,629

Division 2-13

Request:

Was the Navy already giving consideration to replacing the oil-fired central steam plant with a natural gas fired steam plant before the Company negotiated the CHP project? If so, please explain the Company's understanding of the plans. If so, did the Company take into account the elimination of oil burning at some future date in the base case upon which the cost-effectiveness screening was performed? If not, why not?

Response:

During the Company's review of the proposed CHP project, there was no indication that the Navy was considering either replacing or removing oil firing capability at the central steam plant; in fact, the proposed CHP system will still require oil fired steam production during very cold weather. The Navy is one of only a few customers remaining on an interruptible gas service, where the Navy will continue its long history of burning oil at the central plant back-up boilers below a curtailment temperature.

The CHP savings estimates include some continuing oil usage, since the Navy intends to maintain dual fuel capability and interruptible gas service to the back-up central plant steam boilers. The CHP system will become the primary steam generating source due to the more favorable economics of cogenerating steam and electricity. The CHP will not be a dual fuel generator.

Division 2-14

Request:

Please provide an estimate of what the total amount of the earned incentive is likely to be for the Company's shareholders if the project is successful. In providing this estimate, please provide a schedule showing how the shareholder incentive component attributable to the project would be calculated, using the parameters for calculating shareholder incentives as provided in the Annual Energy Efficiency Plan for 2018.

Response:

Under the 2018 Energy Efficiency Program Plan, shareholder incentive calculation, an incentive can only be earned if a sector achieves at least 75% of its MWh and MW goals. The Navy CHP project would have to be successfully delivered in addition to all of the other projects necessary to achieve the overall C&I sector target for the Company to earn an incentive.

From the 2018 EEPP, Page 36, the electric shareholder incentive is:

- From 75% of savings to 100% of savings:
  - Incentive = SB x (0.15 x % of savings achieved – 0.10)
    - x 0.7 for electric energy savings
    - x 0.3 for electric demand savings

  Where SB is Spending Budget

Assuming that the SB is equal to the Navy incentive of $7,200,000 and is the project's annual MWh and MW are 100% achieved, then the calculation to estimate the incentive is:

$7,200,000 * (0.15*1-.1) = $360,000 total estimated incentive

- $360,000 * 0.7 for electric energy = $252,000
- $360,000 * 0.3 for demand savings = $108,000

Additionally, the estimated incentive may be delivered in portions over several years because the energy and demand savings may be achieved according to the stages of the project described in PUC 1-1.

Redacted

Division 2-15

Request:

Please describe the electric interconnection to the National Grid system that serves the Navy at the proposed location of the CHP unit. In providing this description, please identify the voltage and indicate whether the interconnection is made directly with facilities classified as distribution and/or transmission. Please provide any maps and diagrams available to illustrate.

Response:

The CHP unit will be connected behind the Navy Substation primary metering located on Access Road, Newport RI.