The Narragansett Electric Company
d/b/a National Grid

Request for Approval of a Gas Capacity Contract and Cost Recovery

June 30, 2016

Submitted to:

Rhode Island Public Utilities Commission
RIPUC Docket No. _____

Submitted by:

nationalgrid

Letter & Transmittal Documents

Jennifer Brooks Hutchinson
Senior Counsel

June 30, 2016

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: The Narragansett Electric Company d/b/a National Grid
Request for Approval of a Gas Capacity Contract and Cost Recovery
Docket No. _____

Dear Ms. Massaro:

On behalf of National Grid,[1] I enclose ten (10) copies of a 20-year contract Precedent Agreement with the Algonquin Gas Transmission Company LLC (Algonquin) for natural gas transportation capacity and storage services on Algonquin's Access Northeast Project (ANE Project) (the ANE Agreement or Proposed Agreement), together with supporting testimony and schedules, as further described herein. National Grid seeks approval of the Proposed Agreement based on a finding that the Proposed Agreement is commercially reasonable and will provide net benefits at a reasonable cost to National Grid's customers in the form of improved electric reliability and lower electric retail prices pursuant to the Rhode Island Affordable Clean Energy Security (ACES) Act.[2] A copy of the executed Proposed Agreement is included with this initial filing as Schedule TJB/JEA-1 (Highly Sensitive Confidential Information).

On July 3, 2014, Rhode Island enacted the ACES Act, codified at Chapter 39-31 of the Rhode Island General Laws. Section 39-31-6(1)(v) of the ACES Act authorized the Company to enter into long-term contracts for natural gas pipeline infrastructure and capacity that are commercially reasonable and advance the purposes of Chapter 39-31, as outlined above, at levels beyond those commitments necessary to serve local gas distribution customers. That section also

[1] The Narragansett Electric Company d/b/a National Grid (referred to herein as National Grid or the Company).

[2] The Rhode Island Affordable Clean Energy Security Act defines "commercially reasonable" as "terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see in transactions involving regional-energy resources and regional-energy infrastructure. Commercially reasonable shall include having a credible project operation date, as determined by the commission, but a project need not have completed the requisite permitting process to be considered commercially reasonable. Commercially reasonable shall require a determination by the commission that the benefits to Rhode Island exceed the cost of the project. The commission shall determine, based on the preponderance of the evidence, that the total energy security, reliability, environmental and economic benefits to the state of Rhode Island and its ratepayers exceed the costs of such projects." R.I. Gen. Laws § 39-31-3.

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states that the Company may do so either directly, or in coordination with, other New England states and instrumentalities or utilities. Consistent with the ACES Act, the Company has pursued an innovative solution to these issues that will provide substantial net benefits to Rhode Island, as described in more detail in the enclosed filing.

To facilitate the PUC's review of the enclosed filing, the Company is providing an Executive Summary of the ANE Project, the procurement process, and the Proposed Agreement as Attachment 1 to this filing letter. The Company's proposal includes the following key components:

- An Electric Reliability Service Program (ERSP), which sets parameters for the release of capacity and sale of liquefied natural gas (LNG) supply available by virtue of the ANE Agreement. If approved, the Company will release the capacity secured under the ANE Agreement to the electric market in accordance with an Electric Reliability Service tariff, which is subject to approval by the Federal Energy Regulatory Commission (FERC), and in accordance with a state-approved ERSP.

- Utilization by the ESRP of a Capacity Manager, to be selected following a competitive bidding process, to administer the release of the contracted gas capacity to the market. The Capacity Manager's responsibilities would include releasing the capacity in a manner consistent with the EDC guidelines, and reporting on results, with compensation paid to the Capacity Manager in the form of a fixed fee.

- A financial incentive linked to the ANE Agreement to compensate the Company for its innovative efforts, and allow the Company to share in a small fraction of the net economic benefits its efforts will create for customers, and create an inducement for future innovative efforts by the Company that promise to yield additional customer benefits

- A mechanism for cost recovery of contract-related costs and the crediting of net revenues associated with the release of capacity, together with the associated tariff. The mechanism is designed in a similar manner to contract cost recovery mechanisms previously approved by the PUC for renewable generation contracts and nets the costs against expected revenues so that customers are charged a net cost that is recovered from all customers through a uniform per kWh rate.

In support of the Proposed Agreement, the Company is submitting the following testimony and supporting schedules:

- Joint testimony and supporting schedules of Mr. Timothy J. Brennan and Mr. John E. Allocca. Mr. Brennan is a Director in the Regulatory Strategy and Integrated Analytics Group for National Grid USA Service Company, Inc. (the Service Company). Mr. Allocca is the Director of Gas Contracting and Compliance in the Service Company. Mr. Brennan's and Mr. Allocca's Joint Testimony provides an overview of the filing and addresses several aspects of the Company's proposal including: the energy-market conditions that are giving

rise to the need for incremental interstate gas pipeline transportation and storage services; the net benefits analysis prepared in relation to the proposed ANE Agreements; the procurement process conducted by the Company; identification of possible alternatives to the ANE Project and the economic and non-economic factors used by the Company to evaluate the ANE Project; how the Company will manage contract quantities and maximize the release revenues received by customers; and an overview of the proposed ratemaking mechanism.

- Testimony and supporting schedules of Mr. Richard Porter of Black & Veatch Management Consulting (Black & Veatch), addressing the Company's evaluation of RFP responses. Black and Veatch's assessment includes an explanation of the review of the responses to determine which were eligible for additional analysis performed by Black & Veatch for evaluation of the long-term economic benefit to electric customers.

- Testimony and supporting schedules of Mr. Gray Wilmes of Black & Veatch, addressing the economic benefits of the ANE Agreements.

- Testimony and supporting schedules of Mr. Andrew Byers of Black & Veatch, addressing the environmental benefits of the ANE Agreement.

- Testimony and supporting schedules of Mr. Michael J. Vilbert of The Brattle Group, quantifying the impact any financial risk associated with the Proposed Agreements would have on the Company's cost of capital in the absence of fully assured cost recovery over the duration of the Proposed Agreements.

- Testimony of Mr. Michael C. Calviou, Senior Vice President, U.S. Regulation and Pricing for the Service Company, addressing the role that utility innovation can serve to benefit the State of Rhode Island and its utility customers, and presenting the Company's request for the financial incentive described above.

- Testimony of Ms. Ann Leary, Manager of New England Gas Pricing in the Regulation and Pricing Department of the Service Company, explaining the mechanism by which the Company will recover contract-related costs and flow back to customers the net revenues associated with the release of capacity and any associated sale of storage made by the Company or its Capacity Manager. Ms. Leary's testimony and exhibits also presents potential bill impacts for customers relating to the contract costs. The Company has included a Capacity Cost Recovery Provision tariff, which allows the Company to recover all incremental costs associated with the ANE Agreement, as well as the Company's proposed financial incentive, as Schedule AEL-1.

- Testimony of Mr. Jeremy J. Newberger, Manager for Energy Efficiency Policy and Evaluation in the Service Company's Rhode Island Program Strategy Group, describing the role of the Company's Energy Efficiency programs in evaluation of alternatives.

In accordance with the standard of review established by § 39-31-6(1)(vii) of the ACES Act, the Company's filing demonstrates that the proposed ANE Agreement is consistent with the public interest in that the Proposed Agreement: (1) is commercially reasonable; (2) has satisfied the requirements for the solicitation; (3) is consistent with the region's GHG reduction goals; and (4) is consistent with the purposes of the ACES Act. If approved by the PUC, the Company's customers will be the direct beneficiaries of the incremental release of gas-transportation capacity to the market, with improved electric reliability and price relief expected to result from the procurement. The quantitative and qualitative analyses conducted in support of the Company's proposal indicate that the ANE Project has the ability to impact the reliability and pricing issues affecting the New England region. The Company estimates substantial net benefits associated with the ANE Agreement, both regionally, and specifically for Rhode Island customers.

As required by the ACES Act, the Company consulted with the Rhode Island Office of Energy Resources (OER) and the Rhode Island Division of Public Utilities and Carriers (Division) in the selection of the ANE Project. In addition to the analysis performed by the Company, at the request of the OER and the Division, the Company also performed several other sensitivities, and evaluated proposals for a determination of net benefits. These additional sensitivities and proposals are discussed in greater detail in the testimony of Mr. Porter and were provided to the OER and Division prior to the filing of this proposal.

The solution proposed by the ANE Project is sized as a regional solution and will require other New England states and other electric distribution companies to take responsibility for proportional share of the costs of the projects, which are necessary to achieve the benefits of lower electricity rates and increased reliability across the New England region. Even with the PUC approval of the ANE Agreement, the ANE Project will require additional subscriptions before Algonquin will be obligated to proceed with the ANE Project. Timely approval from the PUC for the Rhode Island load share on the ANE Project is critical in moving the entire process forward. Given the significant benefits available to Rhode Island customers as a result of the implementation of the ANE Project, it will be important for Rhode Island to monitor developments and allow for adaptations and adjustments to achieve implementation of the ANE Project.

The Company submits that ANE Agreement meets the burden of the PUC's standard of review pursuant to R.I. Gen. Laws § 39-31. Accordingly, the Company respectfully requests that the PUC approve the Proposed Agreement and related tariffs pursuant to the ACES Act as expeditiously as possible.

This filing also includes a Motion for Protective Treatment in accordance with Rule 1.2(g) of PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). The Company seeks protection from public disclosure of certain highly sensitive and proprietary modeling and analysis provided by the Company's third-party consultants, as well as confidential bidder and pricing information. Accordingly, the Company has provided the PUC with one (1) complete, unredacted copy of the confidential documents in a sealed envelope marked **"Contains Highly Sensitive Confidential Information – Do Not Release,"** and has included redacted copies of these materials for the public filing.

Thank you for your attention to this transmittal. If you have any questions concerning this filing, please contact me at 401-784-7288, or John K. Habib at Keegan Werlin LLP 617-951-1400.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Leo Wold, Esq.
Steve Scialabba, Division
Nick Ucci, Office of Energy Resources

REQUEST FOR APPROVAL OF A GAS CAPACITY CONTRACT AND COST RECOVERY

Executive Summary RIPUC Docket No. _____ June 30, 2016

Introduction

National Grid[1] has pursued an innovative solution to the regional natural gas capacity constraints through the execution of a Precedent Agreement with Algonquin Gas Transmission Company LLC (Algonquin) for natural gas transportation capacity and storage services on Algonquin's Access Northeast Project (ANE Project) (the ANE Agreement or Proposed Agreement). The Company pursued this solution pursuant to the Rhode Island Affordable and Security Act (ACES). In enacting the ACES Act, the Rhode Island general assembly found and declared:

(1) The state and New England face significant short and long-term energy system challenges that may undermine the reliable operation of the bulk electric system and spur unsustainable levels of price volatility, and that these challenges may have a substantial impact on energy affordability for ratepayers and undermine the economic competitiveness of our state by serving as a detriment to capital investment and job growth; and

(2) Planned retirements of fossil-fuel, nuclear, and other electric generators, along with lack of new interstate natural gas pipeline infrastructure and capacity into the region, may exacerbate these conditions; and

(3) Rhode Island benefits from a holistic energy strategy that pursues both local investment in clean energy resources, such as energy efficiency and renewable distributed generation, and regional investment in energy infrastructure projects that strengthen system reliability and diversify our supply portfolio. The combination of these strategies advance our economic development interests and environmental quality; and

(4) Rhode Island is committed to the increased use of no-and low-carbon energy resources that diversify our energy supply portfolio, provide affordable energy to consumers, and strengthen our shared quality of life and environment, and new energy infrastructure investments may help facilitate the development and interconnection of such resources; and

(5) Rhode Island is part of an integrated, regional energy system and addressing these challenges, while meeting state policy goals, requires a coordinated, multi-state approach built upon collaboration and utilizing appropriate expertise and stakeholder processes of regional entities including, but not limited to, the New England State's Committee on Electricity, ISO-New England, Inc. and The New England Power Pool that takes into

[1] The Narragansett Electric Company d/b/a National Grid (referred to herein as National Grid or the Company).

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account affordability, energy security, reliability, fuel diversity, and environmental sustainability.[2]

The stated purpose of the ACES Act is to (1) secure the future of the Rhode Island and New England economies, and their shared environment, by making coordinated, cost-effective, strategic investments in energy resources and infrastructure such that the New England states improve energy system reliability and security; enhance economic competitiveness by reducing energy costs to attract new investment and job growth opportunities; and protect the quality of life and environment for all residents and businesses; (2) utilities coordinated competitive processes, in collaboration with other New England states and their instrumentalities, to advance strategic investment in energy infrastructure and energy resources, provided that the total energy security, reliability, environmental, and economic benefits to the state of Rhode Island and its ratepayers exceed the costs of such projects, and ensure that the benefits and costs of such energy infrastructure investments are shared appropriately among the New England states; and (3) encourage a multi-state or regional approach to energy policy that advances the objectives of achieving a reliable, clean-energy future that is consistent with meeting regional greenhouse gas (GHG) reduction goals at a reasonable cost to ratepayers.[3]

Overview of the ANE Project

The Access Northeast Project (ANE Project) is designed to provide increased natural gas deliverability to the New England market to directly serve the gas-fired electric generating plants on the Algonquin Gas Transmission Company LLC (Algonquin) and Maritimes and Northeast Pipeline systems. The ANE Project is designed to provide delivery-point flexibility to serve generators in four separate sub-regions of the market, referred to as Power Plant Aggregation Areas, which include Connecticut, southeastern Massachusetts and Rhode Island, central and eastern Massachusetts, and Northern New England. The ANE Project will provide customers in these markets with: (1) 500,000 MMBtu/day of access to the gas supplies in the Marcellus Shale region in Northeastern Pennsylvania through Algonquin's existing direct connections to the Millennium Pipeline at Ramapo, New York; the interconnection with Tennessee at Mahwah, NJ; and the interconnection with Iroquois at Brookfield, CT; and (2) 400,000 MMBtu/day of access to a proposed market-area domestic LNG storage facility. The new LNG storage facility in Acushnet, MA will provide storage withdrawal capacity for 400,000 MMBtu/day, liquefaction capability up to 54,000 MMBtu/day, and 6,400,000 MMBtu of LNG storage capacity.[4] Together, the transportation and storage facilities will provide a total of 900,000 MMBtu/day of firm,

[2] R.I. Gen. Laws § 39-31-1.
[3] R.I. Gen. Laws § 39-31-2.
[4] Based on total storage capacity of 6,373,592 Mcf after adjusting for the heel and an assumed BTU content of 1,030 BTU/cubic foot.

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incremental, integrated transportation and LNG deliverability to multiple generators; thereby enabling net benefits to electric customers.

The Company's proposal addresses additional regulatory approvals that are necessary for the ANE Project to move forward. Companies engaged in the interstate transportation and storage of natural gas in interstate commerce must receive a "Certificate of Need and Public Necessity" from FERC in order to construct a major project. FERC is directly involved in: evaluation of the costs of the projects; the rates to be charged by the sponsor; and compliance with FERC regulations. The U.S. Department of Transportation is involved in safety issues. A specific FERC concern is that the project must be supported by long-term contracts and not involve subsidies from other pipeline customers. Therefore, like other interstate pipeline projects, the ANE Project will require state-approved, long-term contracts as a prerequisite for its FERC approvals. For this reason, New England states other than Rhode Island must also approve the ANE Project. On December 5, 2013, the Governors of the six New England states jointly acknowledged the need for new natural gas infrastructure serving the New England region, setting in motion a coordinated effort to advance a regional energy infrastructure initiative. The commitment to infrastructure development encompassed within the New England Governors' joint statement is the impetus for the ANE Project.

To date, all New England states except Vermont have laws or regulations in place, or proposed for effect, that allow for the development of natural gas infrastructure to serve power generation. Consistent with the established regulatory structures, efforts are underway in each of the six states to consider participation and support for infrastructure contracts that will alleviate reliability and cost concerns for New England's retail electric customers. For example, Eversource Energy will seek state regulatory approval in New Hampshire for an ANE agreement equal to the load share served by Public Service Company of New Hampshire. In Connecticut, the Department of Energy and Environmental Protection is expected to conduct an RFP and direct the EDCs to enter into precedent agreements for gas transportation capacity.

Procurement Process

On October 23, 2015, the Company issued a Request for Proposal (the RFP) to solicit proposals for interstate capacity/gas supplies to further the goals of reduction of the cost of electricity and increasing the reliability of the New England electric system to benefit electric distribution companies. Consistent with the requirements of the ACES Act, the RFP noted that potential bidders would be required to demonstrate that any proposed contracts and strategies for reducing the costs of electricity for their electric customers are the most appropriate alternative of the range of alternatives that may be leveraged to achieve reduced electricity costs while ensuring reliability for customers.

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The Company received nine bids on November 13, 2015 encompassing five interstate pipeline companies and four LNG suppliers. The pipelines included Algonquin, Tennessee Gas Pipeline Company LLC (Tennesse), TransCanada PipeLines Limited, Portland Natural Gas Transmission System, and Iroquois Gas Transmission System, L.P. The LNG suppliers included Cavus Energy LLC, GDF Suez Gas NA LLC, Repsol Energy North America Corporation, and Stolt LNGaz. The bids were evaluated by Narragansett with the assistance of Black & Veatch in a three-step process.

Black & Veatch developed a matrix to determine if each proposal satisfied the key requirements of the RFP. Those proposals that satisfied the key requirements were considered for potential economic benefit modeling. Only the proposals submitted by Algonquin and Tennessee satisfied the threshold criteria.

Black & Veatch utilized an Integrated Market Modeling (IMM) process to generate wholesale market prices for natural gas, and wholesale locational marginal prices at key New England transmission zones. GPCM was used to model the New England natural gas market, while PROMOD was used to model the ISO-NE electric market. This IMM process was used by Black & Veatch to estimate the price impacts of natural gas and electric infrastructure solutions on the New England energy markets. Using this process, Black & Veatch analyzed the ANE Project. The key capabilities of the ANE Project that position it to have a major impact on regional reliability and wholesale market prices are that the project: (1) reaches the largest number of power plants; (2) provides access to liquid supplies of scale and is designed to minimize the need to reach back further to more liquid points with larger demand charges; and (3) is designed to provide operational flexibility through a market area domestic LNG facility that will support no-notice and fast-start services for electric generators. In addition, Algonquin, as sponsor of the ANE Project, has ample experience constructing, operating, and expanding natural gas transportation in New England. That experience includes the currently underway Algonquin Incremental Market Project and the Atlantic Bridge Project, which similarly expand the capacity of the Algonquin System. In accordance with its determination that the ANE Project provides the option with the highest capability to impact the reliability and pricing issues affecting the New England region, the Company entered into negotiations with Algonquin that resulted in the Proposed Agreement for which the Company now seeks approval. The Proposed Agreement sets forth the rights and obligations of Algonquin and the Company during the pre-approval process before FERC and requires the Company to execute a service agreement upon acceptable FERC approval.

Proposed Agreement

The contract quantity for the Proposed Agreement was determined through a computation of New England load share and represents the Company's load shared within the load served by investor-owned electric distribution companies (EDC) in New England. The ANE Agreement

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provides a 20-year term beginning on the in-service date of the first of four planned phases of the ANE Project. The Project is scheduled to go into service beginning with the first phase starting on November 1, 2018, the second phase starting on November 1, 2019, the third phase commencing on November 2, 2020, and the fourth and final phase commencing on May 1, 2021. The Company and the other EDC customers for the Access Northeast (ANE) Project have negotiated a levelized cost for the duration of the 20-year contract term. The rate paid by the EDCs will be based on the actual cost of construction subject to a cap. The ANE Agreement also contains provisions related to cost and cost caps, regulatory approvals, Right of First Refusal, discounts for contract extensions, and Most Favored Nation Status.

The Proposed Agreement provides significant non-price attributes, such as the inherent flexibility contained in the ERS Rate Schedule which will allow generators to take gas under a "no-notice" service. The Access Northeast (ANE) Project is directly connected to nearly 70 percent of New England's electric generation capacity.

Further, the ANE Project provides environmental benefits by reducing nitrogen oxides (NO_x) emissions by approximately 15%, sulfur dioxide (SO_2) emissions by approximately 25%, and GHG emissions by 0.5% in the New England region. In addition to regional benefits, there are some direct benefits to Rhode Island specifically. For example, Algonquin has proposed to upgrade an existing compressor station located in Burrillville, Rhode Island. This upgrade will consist of retirement of three existing reciprocating internal combustion engine compressors and their replacement with two new natural gas-fired Taurus turbine compressor units.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Review of Precedent Agreement with Algonquin Gas Transmission LLC for Capacity on the Access Northeast Project Pursuant to R.I.GL. § 39-31 *et seq.*

Docket No. _____

NATIONAL GRID'S REQUEST FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

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

I. BACKGROUND

On June 30, 2016, National Grid is filing with the PUC its request for approval of a precedent agreement with Algonquin Gas Transmission LLC (Algonquin) for capacity on the Access Northeast Energy Project (ANE Project). In support of its request for approval, National Grid is submitting initial testimony and supporting exhibits including a copy of the precedent agreement and the Company's analysis of the precedent agreement and ANE Project, including proprietary modeling information and analysis

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

provided by the Company's third-party consultants. For example, the testimony of Gary Wilmes of Black & Veatch Management Consulting LLC (Black & Veatch), provides detailed cost-benefit analysis related to the ANE Project that was created using Black & Veatch's proprietary modeling.

Specifically, the Company is seeking protective treatment for each of the following document submitted in support of its request for approval:

- Joint, Initial Testimony of Timothy J. Brennan and John E. Allocca together with supporting Schedule TJB/JEA-1 containing confidential contractual terms and pricing information;

- Initial Testimony of Ann E. Leary together with supporting Schedules AEL-2 through AEL-4 containing confidential pricing information;

- Initial Testimony of Michael J. Vilbert containing confidential pricing information;

- Initial Testimony of Gary J. Wilmes from Black & Veatch together with supporting Schedules GJW-1, GJW-2, and GJW-3 containing confidential and proprietary analysis of the ANE Project;

- Initial Testimony of Richard W. Porter from Black & Veatch together with supporting Schedule RWP-3 containing confidential bid terms and pricing information regarding the Request for Proposals issued by the Company; and

- Initial Testimony of Andrew C. Byers from Black & Veatch together with supporting Schedule ACB-2 containing confidential and proprietary analysis of the ANE Project.

The Company's affiliates Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid have filed a similar request for approval of

precedent agreements with Algonquin for capacity on the ANE Project with the Massachusetts Department of Public Utilities (the Department). As detailed below, the Department has approved a two tier confidential document designation to provide an added layer of protective treatment in this related proceeding. This additional layer of protective treatment is necessary because certain intervenors granted full-party status in the Massachusetts proceeding are classified as bidders with respect to the request for proposals (RFP) that resulted in the precedent agreement that is the subject of this proceeding. The RFP was jointly simultaneously with the RFP issued by the Company's Massachusetts affiliates and Eversource Energy and, therefore, the Company expects that some or all of the parties who have intervened in the Massachusetts proceeding will also seek to intervene in this proceeding. Therefore, in order to ensure that confidential information is treated consistently across jurisdictions, the Company proposes to implement the same two-tier system for this proceeding. If the same parties intervene in this proceeding and the two-tier system is not utilized, the two-tier system being used in Massachusetts will be undermined and the Company (and its affiliates) will be placed at a competitive disadvantage. This result would be particularly problematic because it is expected that other pipeline projects will be proposed in the near future to address capacity restraint in the New England region. If other bidders to the RFP were to receive highly sensitive confidential information,

The deadline for intervention in the Massachusetts proceeding was on March 7, 2016. The Department granted full-party status in such proceeding to the Massachusetts Office of Attorney General, Conservation Law Foundation, the Massachusetts Department of Energy Resources, NextEra Energy Resources, LLC,

Algonquin Gas Transmission LLC, ENGIE Gas & LLG LLC (ENGIE), Portland Natural Gas Transmission System (PNGTS), TransCanada Pipelines Limited (TransCanada), Tennessee Gas Pipeline Company LLC, Direct Energy Business, LLC and Directive Energy Services, LLC, Repsol Energy North America Corporation (Repsol), the Town of Dracut, and the Low-Income Weatherization and Fuel Assistance Program. The Department allows full-parties to receive copies of all documents filed by the Company's Massachusetts' affiliates, including confidential information. This would allow intervenors such as NEER, Repsol, TransCanada, PNGTS, and ENGIE to review confidential information including bids submitted to the Company and its Massachusetts' affiliates in response to the RFP by direct competitors.

Therefore, and in recognition of: (1) the highly sensitive nature of the information contained in the initial Massachusetts filing and the fact that that highly sensitive information would form the basis of responses to information requests, cross examination, briefing, etc. in such proceeding; and (2) the fact that certain full party intervenors are classified as bidders to the RFP process, a Non-Disclosure Agreement (NDA) was developed in the Massachusetts proceeding to restrict review of what National Grid designated as "Highly Sensitive Confidential Information" to an intervenor's outside counsel and/or a mutually agreed-to third-party neutral consultant (the Highly Sensitive Confidential Information NDA). Highly Sensitive Confidential Information provided pursuant to the Highly Sensitive Confidential Information NDA may not be disclosed to an intervenor or its internal staff due to the intervenor's position as a bidder, generator and/or market participant. In the Massachusetts proceeding, the Company's Massachusetts affiliates also developed a separate NDA (Standard NDA) to

cover materials that, while confidential, do not constitute highly sensitive information covered by the Highly Sensitive Confidential Information NDA. Information filed pursuant to the Standard NDA may be reviewed directly by the intervenor or its internal staff.

In this proceeding, the Company proposes to adopt the same approach to ensure consistency across New England jurisdictions, and to prevent intervenors from gaining access to confidential information that has been restricted in Massachusetts. Each of the documents referenced in this Motion are classified by the Company as Highly Sensitive Confidential Information. This is consistent with the initial filing made by the Company's Massachusetts affiliates to the Department.

The Company is providing redacted and unredacted versions of each of these documents. Each of these documents and/or files contains confidential and proprietary contractual or economic analysis information. Therefore, National Grid requests that the PUC give the information contained in the unredacted version of the Highly Sensitive Confidential Information Documents confidential treatment.

II. LEGAL STANDARD

The PUC's 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.G.L. §38-2-1 *et seq.* Under 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.G.L. §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 APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I.G.L. §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 (1) to impair the Government's ability to obtain necessary information in the future; or (2) to 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).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily 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 the un-redacted versions of the Confidential Initial Filing contains confidential and proprietary bidder information, including pricing information and bid-evaluation information. In addition, the Confidential Initial Filing contains confidential contractual terms including pricing information that was negotiated by the Company with Algonquin. This information was obtained from bidders under a confidentiality agreement and contains their confidential pricing data. National Grid is providing the Confidential Initial Filing on a voluntary basis to assist the PUC with its

decision-making in this proceeding. Disclosure of this information would impact the competitive position of these parties, and such disclosure would impede National Grid's future ability to obtain bids and/or favorable contractual terms. Such disclosure would have a negative impact not only on National Grid but on National Grid's customers by impeding National Grid's ability to obtain the best price for future capacity agreements.

IV. CONCLUSION

Accordingly, the Company requests that the PUC grant protective treatment to (i) the un-redacted versions of joint, initial testimony of Timothy J. Brennan and John E. Allocca together with supporting Schedule TJB/JEA-1; the initial testimony of Ann E. Leary together with supporting Schedules AEL-2 through AEL-4 containing confidential pricing information; initial testimony of Michael J. Vilbert; initial testimony of Gary J. Wilmes from Black & Veatch together with supporting Schedules GJW-1 through GJW-3; initial testimony of Richard W. Porter from Black & Veatch together with supporting Schedule RWP-3; and initial testimony of Andrew C. Byers from Black & Veatch together with supporting Schedule ACB-2.

WHEREFORE, the Company respectfully requests that the PUC grant its Motion for Protective Treatment as stated herein.

Respectfully submitted,

NATIONAL GRID

By its attorneys,

Jennifer Brooks Hutchinson (RI Bar #6176)
National Grid
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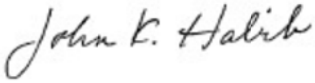

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Dated: June 30, 2016

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

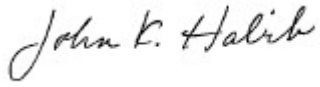
RHODE ISLAND PUBLIC UTILITIES COMMISSION

Review of Precedent Agreement with Algonquin Gas Transmission LLC for Capacity on the Access Northeast Project Pursuant to R.I.G.L. § 39-31 *et seq.*

Docket No. _____

APPEARANCE OF COUNSEL

In the above-referenced proceeding, I hereby appear for and on behalf of The Narragansett Electric Company each d/b/a National Grid.



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Dated: June 30, 2016

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Joint Testimony of
Timothy J. Brennan &
John E. Allocca

JOINT DIRECT TESTIMONY

OF

TIMOTHY J. BRENNAN

AND

JOHN E. ALLOCCA

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I. Introduction

Q. Mr. Brennan, please state your name and business address.

A. My name is Timothy J. Brennan. My business address is 40 Sylvan Road, Waltham, MA.

Q. Please state your business position and responsibilities.

A. I am a Director in the Regulatory Strategy and Integrated Analytics group for the National Grid USA Service Company, Inc. (Service Company), which provides services to Narragansett Electric Company d/b/a National Grid (National Grid or the Company). My primary responsibilities in this position include the understanding and monitoring of the ISO New England (ISO-NE) wholesale electricity markets and system planning process, and representing the National Grid companies' and our customers' interests in the associated stakeholder processes and regulatory proceedings, as well as advocating on their behalf, as necessary, for enhanced reliability and more economically efficient market results.

Q. Please summarize your educational background and your professional experience.

A. I have worked for National Grid for more than 28 years since graduating from Tufts University in 1988 with a Bachelor of Science in Mechanical Engineering, and a

minor in Engineering Management. My professional experience has included responsibilities in the areas of power plant engineering, wholesale market trading, energy supply procurement, and transmission strategy. For more than 18 years, I have represented National Grid and its customers in the ISO-NE and New England Power Pool (NEPOOL) stakeholder processes, promoting the development and enhancement of competitive wholesale electricity markets and a cost-effective and reliable grid for New England. I am also beginning my third year as a NEPOOL Officer, as Vice-Chair, serving on behalf of the Transmission Sector.

Q. Have you previously testified in regulatory proceedings?

A. I have testified before the Rhode Island Public Utilities Commission (PUC) in Docket No. 4570 regarding The Narragansett Electric Company's Request for Proposals pursuant to the Rhode Island Affordable Clean Energy Security Act, R.I. Gen. Laws § 39-31-6. I have also participated in many regulatory proceedings through assisting in the preparation of comments, protests, answers, etc., and have participated as a panelist in the ~~"~~Demand Response in Organized Wholesale Energy Markets Technical Conference" held at the Federal Energy Regulatory Commission (FERC) on September 13, 2010 in Docket No. RM10-17-000. I have also recently co-sponsored written testimony with Mr. Allocca in Massachusetts in Massachusetts Electric

Company and Nantucket Electric Company d/b/a National Grid, D.P.U. 16-05, in support of substantially similar agreements as those presented in this proceeding.

Q. Mr. Allocca, please state your name and business address.

A. My name is John E. Allocca. My business address is 100 East Old Country Road, Hicksville, NY 11801.

Q. Please state your business position and responsibilities.

A. I am the Director of Gas Contracting and Compliance for the Service Company and am responsible for the acquisition of long term gas supply and pipeline capacity; gas contract management; intervention in proceedings before the FERC; and, compliance with FERC regulations in connection with National Grid's gas trading activities for Narragansett Electric Company d/b/a National Grid and National Grid USA's gas distribution affiliates in New York and Rhode Island.

Q. Please summarize your educational background and your professional experience.

A. In 1982, I graduated from The Polytechnic Institute of New York with a Bachelor of Science degree in Mechanical Engineering, and in 1988, I graduated from Brooklyn Law School with a Juris Doctor degree. In 1988, I was admitted to practice law in

New York State and in 1990 I was licensed as a Professional Engineer in the State of New York. Prior to joining The Brooklyn Union Gas Company (Brooklyn Union), a National Grid USA affiliate, I held positions as an engineer with a consulting firm and with the U.S. Department of Defense. I joined Brooklyn Union as a research engineer in 1985 and held various engineering positions thereafter. After graduating from Brooklyn Law School, I held various positions as an attorney including Regulatory Counsel, Corporate Counsel for Mergers and Acquisitions, and Senior Transaction Counsel. In 2004, I joined the Energy Procurement area as Director of Contracts. Following the acquisition of KeySpan Corporation (the parent company of Brooklyn Union) by National Grid plc, I assumed my current position as Director of Gas Contracting and Compliance.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I testified before the Massachusetts Department of Public Utilities (the DPU) in D.T.E. 05-40 in support of firm transportation agreements with TransCanada and the Union Gas Pipeline. I also testified in Boston Gas Company and Colonial Gas Company each d/b/a National Grid, D.P.U. 13-157 (2013) and Boston Gas Company and Colonial Gas Company each d/b/a National Grid, D.P.U. 15-34 (2015). In these dockets, the Department approved firm transportation agreements with Algonquin Gas Transmission LLC and Tennessee Gas Pipeline, LLC, respectively. I have also

sponsored testimony in Boston Gas Company and Colonial Gas Company each d/b/a National Grid, D.P.U. 15-129 (2015) and Boston Gas Company and Colonial Gas Company each d/b/a National Grid, D.P.U. 15-130 (2015). I have also recently co-sponsored written testimony with Mr. Brennan in Massachusetts in Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, D.P.U. 16-05, in support of substantially similar agreements as those presented in this proceeding.

Q. What is National Grid requesting in this proceeding?

A. In this proceeding, National Grid is requesting the PUC approval of a 20-year contract between the Company and Algonquin Gas Transmission, LLC (Algonquin) for transportation capacity and storage services on Algonquin's Access Northeast Project (the ANE Project)(the ANE Agreement or the Proposed Agreement).

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support National Grid's request for approval of the Proposed Agreement by providing the following: (1) an overview of the filing and its component parts; (2) an overview of the Company's rationale for entering the Proposed Agreement, including the peak demand and natural gas pipeline capacity issues facing New England electric customers, and the impact of these factors on

electricity prices in the region; (3) a description of the Proposed Agreement, the associated project, and the results of the economic benefits analysis performed for the Company in relation to the Proposed Agreement; (4) a description of the request for proposals (RFP) conducted by the Company to identify potential natural gas capacity infrastructure alternatives available to resolve the pipeline capacity constraints on natural gas deliverability to the region; (5) a summary of the Company's consideration of other possible alternatives (e.g., hydropower, energy efficiency, etc.); (6) a discussion of the manner in which National Grid will manage the contract quantities and maximize the capacity release revenues received by customers; and (7) an overview of the proposed ratemaking mechanism for the costs and revenues attributable to customers in relation to the Proposed Agreement, including costs associated with the innovation incentive proposed by the Company associated with procuring and implementing the Proposed Agreement.

Q. Aside from your testimony, what are the components of the National Grid filing?

A. In addition to our testimony, this filing includes the following:

The testimony and supporting schedules of Mr. Richard W. Porter of Black & Veatch Management Consulting LLC (Black & Veatch) provide (1) a summary overview of the RFP, (2) a summary description of the responses to the RFP and (3) an explanation of the review of the responses to determine which were eligible for additional analysis

performed by Black & Veatch for evaluation of the long-term economic benefit to electric customers.

The testimony and supporting schedules of Mr. Gary J. Wilmes of Black & Veatch provides the economic benefits of the ANE Agreement. Specifically, Mr. Wilmes is sponsoring a report entitled "Evaluation of Long-Term Economic Benefits from Proposed Incremental Energy Infrastructure into New England." The report focuses on the impact of the ANE Project on regional natural gas and electricity prices and the associated long-term benefits to regional electric consumers. In addition, in conjunction with the testimony and schedules of Mr. Andrew J. Byers, of Black & Veatch, Mr. Wilmes' testimony and schedules presents information regarding the projected regional air quality and emissions impact from power generation from the proposed ANE Project. Mr. Byers testimony and schedules also provide information regarding other environmental impacts of the ANE Project.

Dr. Michael J. Vilbert of The Brattle Group, provides testimony and supporting exhibits quantifying the impact any financial risk associated with the Proposed Agreement would have on the Company's cost of capital in the absence of fully assured cost recovery over the duration of the Proposed Agreement.

Mr. Michael C. Calviou, Senior Vice President of U.S. Regulation and Pricing for National Grid, provides testimony regarding the role that utility innovation can serve to benefit Rhode Island and its utility customers and requesting an incentive for innovation in the case of the Proposed Agreement.

Ann Leary, Manager of New England Pricing for National Grid, provides testimony and supporting schedules explaining the mechanism by which the Company will recover contract-related costs and flow back to customers the net revenues associated with the release of capacity. Ms. Leary's testimony and schedules also present potential bill impacts for the Company's customers relating to the contract costs.

Jeremy J. Newberger, Manager for Energy Efficiency Policy and Evaluation for National Grid's Rhode Island energy efficiency programs, provides testimony explaining why energy efficiency is not a viable alternative for alleviating the peak demand issues facing Rhode Island's electric customers.

Q. What schedules are you sponsoring in your testimony?

A. We are sponsoring several schedule including our joint testimony. The schedules that we are sponsoring are designated as follows:

Schedule TJB/JEA-1	Narragansett Precedent Agreement & Service Agreement (**Highly Sensitive Confidential Information**)
Schedule TJB/JEA-2	Regional Coordination
Schedule TJB/JEA-3	Request for Proposals, Issued October 23, 2015
Schedule TJB/JEA-4	Proposed Electric Reliability Service Program

Q. How is the remainder of your testimony organized?

A. After this Introduction section,

- Section II briefly summarizes the legal and regulatory objectives that gave rise to the need for the Company and other electric distribution companies to contract for interstate gas pipeline transportation and storage services.
- Section III summarizes the market supply and demand imbalance conditions in support of the Company's rationale to contract for interstate gas pipeline transportation and storage services.
- Section IV describes the proposed ANE Project, discusses the ANE Agreement that National Grid is proposing to enter into with Algonquin, and reviews the regulatory approvals necessary for the projects to move forward.
- Section V discusses the cost structure and benefits of the ANE project and associated ANE Agreement. Section V also provides an overview of the net-benefits analysis prepared by Black & Veatch in relation to the ANE Agreement.

- Section VI discusses the evaluation and procurement process conducted by National Grid to identify an appropriate contract solution.
- Section VII analyzes the alternatives to the ANE Agreement and demonstrates the basis for National Grid's determination that the proposed project should be undertaken to achieve greater reliability and lower prices for the retail electric market in Rhode Island. Section VII also describes the economic and non-economic factors used by National Grid to evaluate the alternatives and demonstrates that the ANE Project is capable of an impact on the reliability and wholesale market price issues that are creating the imperative for incremental transportation capacity.
- Section VIII describes how National Grid will obtain and maximize the release revenues obtained by National Grid customers.
- Section IX discusses the ratemaking mechanism that will be used to recover contract-related costs and to credit net release revenues to customers.
- Section X discusses the potential financial risk that the Company would face from the Proposed Agreement absent fully assured cost recovery for the duration of the Proposed Agreement and the Company's request for an incentive for innovation.
- Section XI is the conclusion.

II. Legal and Regulatory Support

Q. What legal and regulatory actions prompted the Company to consider entering into a contract such as the Proposed Agreement.

A. On July 3, 2014, Rhode Island enacted the Affordable Clean Energy Security (ACES) Act, codified at Chapter 39-31 of the Rhode Island General Laws. In enacting the ACES Act, the Rhode Island general assembly found and declared:

(1) The state and New England face significant short and long-term energy system challenges that may undermine the reliable operation of the bulk electric system and spur unsustainable levels of price volatility, and that these challenges may have a substantial impact on energy affordability for ratepayers and undermine the economic competitiveness of our state by serving as a detriment to capital investment and job growth; and

(2) Planned retirements of fossil-fuel, nuclear, and other electric generators, along with lack of new interstate natural gas pipeline infrastructure and capacity into the region, may exacerbate these conditions; and

(3) Rhode Island benefits from a holistic energy strategy that pursues both local investment in clean energy resources, such as energy efficiency and renewable distributed generation, and regional investment in energy infrastructure projects that strengthen system reliability and diversify our supply portfolio. The combination of

these strategies advance our economic development interests and environmental quality; and

(4) Rhode Island is committed to the increased use of no-and low-carbon energy resources that diversify our energy supply portfolio, provide affordable energy to consumers, and strengthen our shared quality of life and environment, and new energy infrastructure investments may help facilitate the development and interconnection of such resources; and

(5) Rhode Island is part of an integrated, regional energy system and addressing these challenges, while meeting state policy goals, requires a coordinated, multi-state approach built upon collaboration and utilizing appropriate expertise and stakeholder processes of regional entities including, but not limited to, the New England State's Committee on Electricity, ISO-New England, Inc. and The New England Power Pool that takes into account affordability, energy security, reliability, fuel diversity, and environmental sustainability.[1]

The stated purpose of the ACES Act is to (1) secure the future of the Rhode Island and New England economies, and their shared environment, by making coordinated, cost-effective, strategic investments in energy resources and infrastructure such that the New England states improve energy system reliability and security; enhance economic competitiveness by reducing energy costs to attract new investment and job growth

[1] R.I. Gen. Laws § 39-31-1.

opportunities; and protect the quality of life and environment for all residents and businesses; (2) Utilize coordinated competitive processes, in collaboration with other New England states and their instrumentalities, to advance strategic investment in energy infrastructure and energy resources, provided that the total energy security, reliability, environmental, and economic benefits to the state of Rhode Island and its ratepayers exceed the costs of such projects, and ensure that the benefits and costs of such energy infrastructure investments are shared appropriately among the New England States; and (3) encourage a multi-state or regional approach to energy policy that advances the objectives of achieving a reliable, clean-energy future that is consistent with meeting regional greenhouse gas reduction goals at reasonable cost to ratepayers.[2]

Section 39-31-6 of the ACES Act authorized Narragansett to enter into long-term contracts for natural gas pipeline infrastructure and capacity that are commercially reasonable and advance the purposes of Chapter 39-31, as outlined above, at levels beyond those commitments necessary to serve local gas distribution customers. That section also states that Narraganset may do so either directly, or in coordination with, other New England states and instrumentalities or utilities. Consistent with the ACES Act, the Company has pursued a solution to these issues that will provide substantial net benefits to Rhode Island, as described in more detail herein.

[2] R.I. Gen. Laws § 39-31-2.

Q. Did other New England states pursue similar objectives?

A. Yes. On April 2, 2015, the Massachusetts Department of Energy Resources (DOER) filed a petition with the DPU requesting that the Department open an investigation into the means by which new natural gas capacity may be added to the New England market, including actions that may be taken by the Massachusetts electric distribution companies (EDCs) to address this issue (the DOER Petition). On April 27, 2015, the Department issued an Order in D.P.U. 15-37 opening an investigation into whether: (1) there is an ~~"i~~innovative mechanism" for EDCs or other parties to secure new natural gas capacity into the region to benefit electric ratepayers; (2) it is appropriate for the Department to review for cost-recovery EDC contracts for natural gas capacity under G.L. c. 164, § 94A (Section 94A); and (3) the Department's established standard of review under Section 94A should be different for these contracts.[3]

As noted by the Department in its October 2, 2015 order in D.P.U. 15-37 (D.P.U. 15-37 or the Order), the DOER highlighted industry stakeholders' widespread conclusion that high winter electricity costs in Massachusetts are attributable to natural gas capacity constraints.[4] DOER asserted that new, creative solutions are needed to reduce natural gas capacity congestion and to make sufficient pipeline capacity

[3] *See* Investigation by the Department of Public Utilities on its own Motion into the means by which new natural gas delivery capacity may be added to the New England market, including actions to be taken by the electric distribution companies, D.P.U. 15-37, Order Opening Investigation (April 27, 2015)(Order Opening Investigation).

[4] D.P.U. 15-37, at 2 (*citing* DOER Petition at 1).

available for electricity generation during peak demand periods.[5] DOER further asserted that gains from additional natural gas capacity can reduce ratepayer costs, diversify the energy mix, and secure electric system reliability.[6] To address this problem, DOER proposed that the Department consider authorizing EDCs to contract for new natural gas capacity, enabling gas-fired electric generators to secure firm capacity and thereby serving the electric generation needs of the EDCs' customers.[7]

In D.P.U. 15-37, the Department provided such authorization, including a standard of review that the EDCs must meet to secure approval of contracts for gas capacity, and filing requirements associated with such requests for approval. In doing so, the Department found that, on balance, the DOER and other parties to the proceeding provided sufficient information to support DOER's assessment of current New England wholesale market conditions and to arrive at the conclusion that increasing regional gas capacity will lead to lower wholesale gas and electricity prices.[8] While not making a finding in its Order that voices a preference for any particular project for gas pipeline infrastructure development over any other potential capacity constraint solution, the Department found in the Order that innovative solutions and a menu of

[5] *Id.* at 3.

[6] *Id.*

[7] *Id.* at 4.

[8] D.P.U. 15-37, at 12.

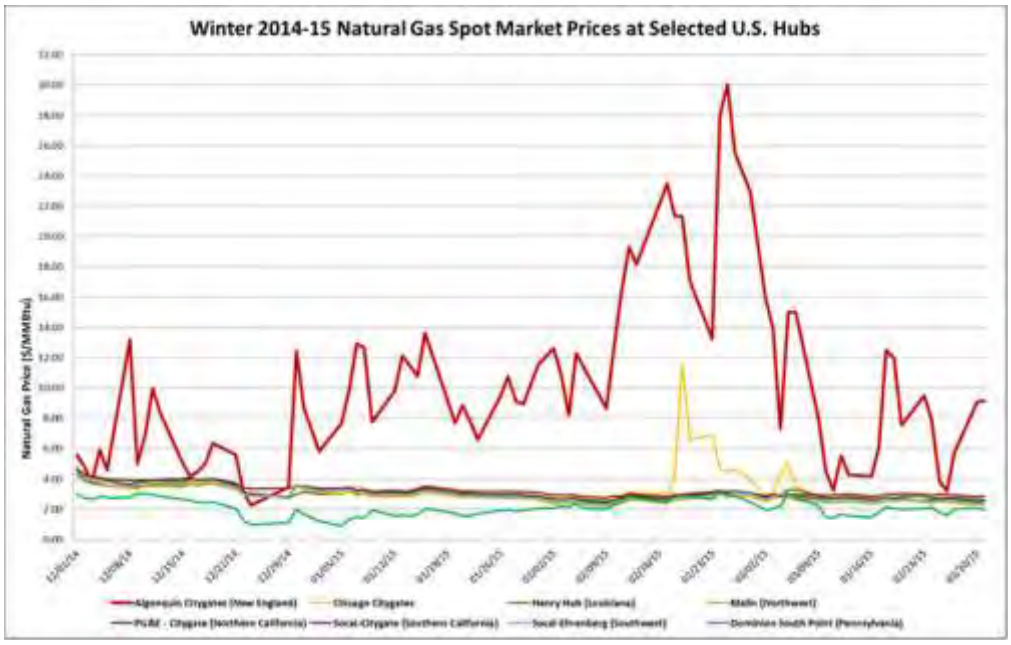
options are required to alleviate capacity constraints and the associated downstream market price impact experienced by Massachusetts customers.[9]

III. Prevailing Market Trends and Portfolio Objectives

Q. Please provide an overview of the Company's rationale for entering the Proposed Agreement.

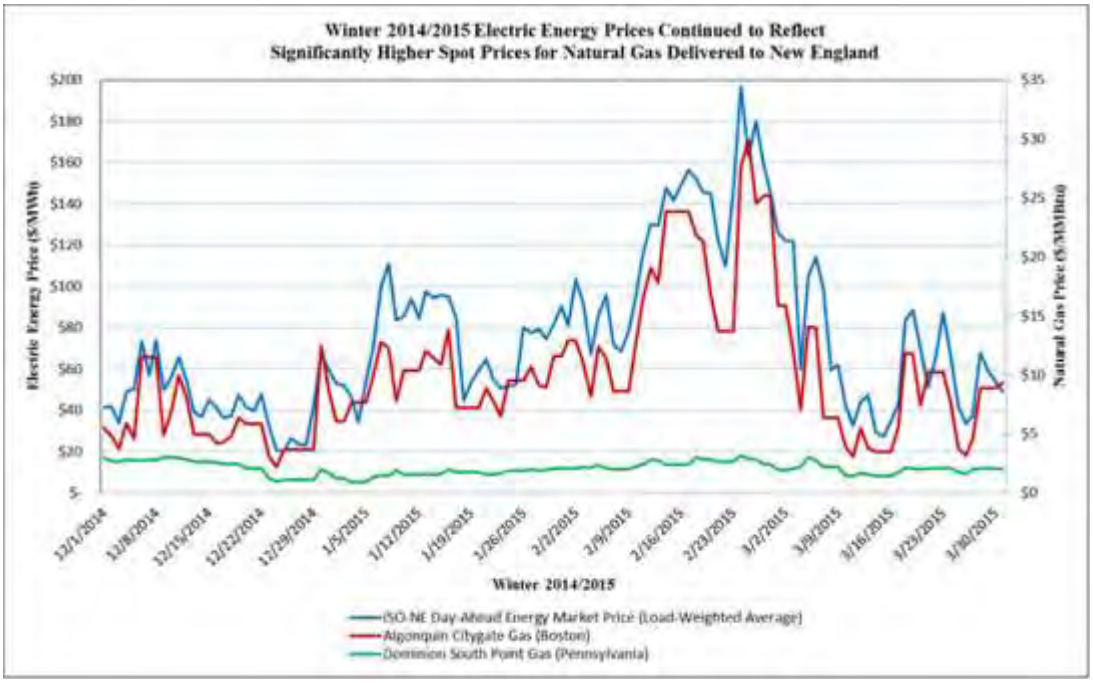
The following chart prepared by the Company shows spot prices for natural gas at trading hubs throughout the country during the winter of 2014-2015. While most of the nation continued to have access to the abundant domestic supplies of low priced natural gas throughout the winter, New England again experienced significantly higher and more volatile spot prices for the natural gas used to fuel much of the electric generation fleet in the region. In fact, the same day New England generators were facing Algonquin Citygate spot prices of nearly $30/MMBtu for fuel, natural gas was available at the Dominion South Point hub in Pennsylvania at prices below $3/MMBtu.

[9] *Id*. Reviews of the potential net benefits of incremental gas pipeline capacity are also underway in Connecticut, New Hampshire and Maine



The chart below shows that the wholesale electric energy prices in New England are strongly linked to and driven by the spot market prices for natural gas in New England. The ISO-NE 2013 Annual Internal Market Monitor has reported on this as follows:

> A number of forces influence the codependency between New England's natural gas and electricity markets: [a]n influx of natural gas-fired generating capacity over the past 15 years; [a]n aging fleet of legacy oil- and coal-fired generators in the electricity market; [t]he decrease in natural gas prices with the increased production of domestic shale gas; [and] [r]elatively static gas pipeline capacity in New England that has had to accommodate a 37% increase in overall natural gas consumption since 1999; 95% of this 37% was for gas generation. The confluence of these forces has resulted in gas-fired generators generating a much higher proportion of electricity in New England, while pushing gas pipeline capacity to its limits during peak gas demand periods.



The table provided below, based on National Grid's analysis of natural gas trading hub data for the past several winters, shows the extent to which the basis differentials, or constraint driven premiums, have increased for the New England spot gas market over the past several winters. While New England saw only 4 days in the winter of 2011/12 with basis differential versus Henry Hub greater than $5/MMBtu, in the winters since then, New England has experienced such natural gas price premiums on 41 to 64 days per winter. Perhaps even more alarming is the increase in number of days in which New England is seeing even greater price premiums. As the data reveals, New England faced 0 days in the winter of 2011/12 with the Algonquin City Gate versus Henry Hub basis differential greater than $10/MMBtu, but has now seen such

significant price premiums 21 to 51 days per winter over the last three years. As ICF reported in its whitepaper, ~~"~~Polar Vortex Review: Natural Gas Perspectives," ~~"~~[b]asis differentials between New England and Henry Hub during the Polar Vortex reached $73/MMBtu in late January 2014. New England paid substantially more for gas than other regions because of limited deliverability capacity."[10]

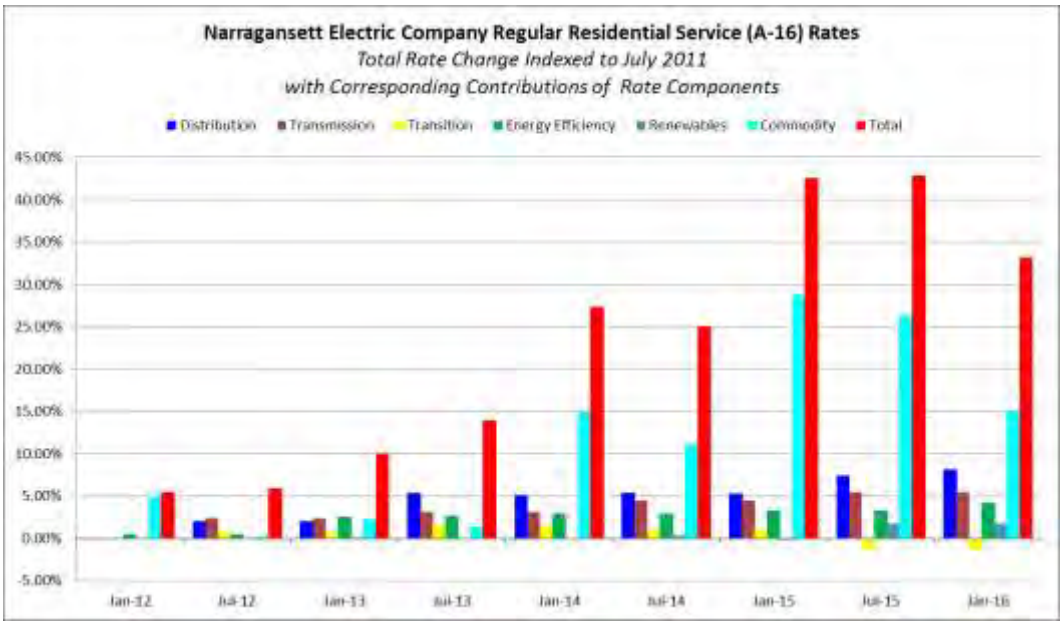
Algonquin City Gate vs. Henry Hub Basis Differential	Number of Days - Winter (Dec -Feb)			
	2011/12	2012/13	2013/14	2014/15
Greater than $2/MMBtu	21	65	77	72
Greater than $5/MMBtu	4	41	64	53
Greater than $10/MMBtu	0	28	51	21
Greater than $20/MMBtu	0	10	20	9
Greater than $30/MMBtu	0	1	7	0
Greater than $40/MMBtu	0	0	3	0

As shown in the table below, the significantly higher prices paid for the natural gas used to fuel much of the region's power generation fleet were the primary drivers of New England wholesale electricity cost increases of $1.7 billion in the winter of 2012/2013, $3.8 billion in the winter of 2013/2014, and $1.6 billion in the winter of 2014/2015, all compared to the winter of 2011/2012 when the region had not yet been exposed to the now persistent and significant pipeline constraints-driven natural gas price basis-differentials, especially in very cold weather conditions, for the New England versus the Mid-Atlantic and Gulf markets.

[10] Briana Adams, ICF International, Polar Vortex in Review: Natural Gas Perspectives (2014).

	Winter (Dec -Feb)			
	2011/12	2012/13	2013/14	2014/15
Avg. Gas Price @ Algonquin City Gate ($/MMBtu)	$ 4.40	$ 11.26	$ 19.56	$ 10.73
Total Cost of ISO-NE Electric Energy Market ($Billions)	$ 1.2	$ 2.9	$ 5.0	$ 2.8

Of course, higher wholesale electric energy market costs, in turn, produce higher retail prices for electric customers. The Company has prepared the chart below showing recent Narragansett Electric Company regular residential service (A-16) rate changes and the corresponding contributions of the rate components. It is clear from the chart that the significant total rate increases customers have experienced in recent winters are being primarily driven by the significant increases in the commodity component (wholesale market supply component) of the retail rate. Relief for our retail electric customers can be achieved once we relieve the interstate pipeline capacity constraints on the reliable and economical deliverability of domestic natural gas supplies to the New England electric energy market.



With this filing, the Company is offering a solution to the need for additional interstate pipeline capacity identified by the Rhode Island general assembly and the Massachusetts DOER.

IV. Description of the Algonquin Project and the Proposed Agreement

A. Description of the ANE Project

Q. Please describe the ANE Project.

A. The ANE Project is designed to provide increased natural gas deliverability to the New England market to directly serve the gas-fired electric generating plants on the Algonquin pipeline as well as the Maritimes and Northeast Pipeline (M&NP) systems.

The project is designed to provide delivery-point flexibility to serve generators in four separate sub-regions of the market, referred to as Power Plant Aggregation Areas (PPAAs), which include Connecticut, southeastern Massachusetts and Rhode Island, central and eastern Massachusetts, and Northern New England. The PPAAs also include the portions of New Hampshire and Maine served by the M&NP pipeline. The ANE Project will provide customers in these markets with: (1) 500,000 MMBtu/day of access to the gas supplies in the Marcellus Shale region in Northeastern Pennsylvania through Algonquin's existing direct connections to the Millennium Pipeline at Ramapo, NY; the interconnection with Tennessee at Mahwah, NJ; and the interconnection with Iroquois at Brookfield, CT; and (2) 400,000 MMBtu/day of access to a proposed market-area domestic LNG storage facility. The new LNG storage facility in Acushnet, MA will provide storage withdrawal capacity for 400,000 MMBtu/day, liquefaction capability up to 54,000 MMBtu/day, and 6,400,000 MMBtu of LNG storage capacity.[11] Together, the transportation and storage facilities will provide a total of 900,000 MMBtu/day of firm, incremental, integrated transportation and LNG deliverability to multiple generators; thereby enabling net benefits to electric customers in the form of lower electricity prices and increased reliability.

[11] Based on net storage capacity of 6,373,592 Mcf after adjusting for the heel and an assumed BTU content of 1,030 BTU/cubic foot.

A new level of service will be provided under the customized ERS tariff rate, which will provide fuel certainty and performance flexibility critical to the electric generators by virtue of a reserved ~~"n~~o-notice" transportation service with an hourly supply option.

B. <u>Description of the Proposed ANE Agreement</u>

Q. Would you please describe the proposed Precedent Agreement with Algonquin?

A. Yes. The proposed Precedent Agreement sets forth the rights and obligations of Algonquin and National Grid during the pre-approval process before FERC and requires National Grid to execute an actual Service Agreement upon satisfaction of all conditions precedent, including acceptable FERC and state regulatory approvals. A copy of the executed Precedent Agreement between Algonquin and Narragansett, and the related Service Agreement that will be executed by the parties upon the fulfillment of all of the conditions precedent, is provided as Schedule TJB/JEA-1 (Highly Sensitive Confidential Information).

The Narragansett Precedent Agreement provides a Maximum Daily Total Quantity (MDTQ) of 64,800 MMBtu/day of firm transportation capacity which includes 36,000MMBtu/day from Mahwah and/or Ramapo and a Maximum Daily Withdrawal Quantity (MDWQ) of 28,800 MMBtu/day from the LNG storage service.

The contract provides a 20-year term beginning on the in-service date of the first of four planned phases. The project is scheduled to go into service beginning with the first phase starting on November 1, 2018, the second phase starting on November 1 2019, the third phase commencing on November 1, 2020, and the fourth and final phase commencing on May 1, 2021. National Grid and the other EDC customers have negotiated a levelized cost for the 20-year duration of the contract.[12] The rate paid by the EDCs will be based on the actual cost of construction subject to a cap.

Q. Would you please explain the phasing aspect of the ANE Project?

A. Yes. Due to the size and scope of the project's construction components, the in-service timeline for the project is divided into four phases, accommodating earlier firm deliverability to the extent possible. Phase 1 anticipates 75,353 MMBtu/day to be available on November 1, 2018; Phase 2 anticipates an additional 189,647 MMBtu/day on November 1, 2019; Phase 3, an additional 235,000 MMBtu/day on November 1, 2020; and Phase 4 completes the project with the estimated in-service of the LNG facility on May 1, 2021, achieving the final 400,000 MMBtu/day of the project volumes of 900,000 MMBtu/day.

[12] Under current FERC regulations, pipelines are not required to file rate cases on any particular schedule. FERC allows pipelines to negotiate rates with customers under certain guidelines under non-discriminatory conditions. Levelized rates are one of the features that most customers of incremental pipeline expansion insist upon.

Q. Would you please explain how the contract quantities were determined?

A. The contract quantities were determined through a computation of New England load share and represent the Narragansett load share within the load served by investor-owned EDCs in New England. New England load share for investor-owned EDCs, including Narraganset, was derived by determining the respective shares of the 2014 Annual Average of the Monthly Network Load Peak Value in kW reported by ISO-NE. This information is filed annually with FERC as part of the Participating Transmission Owner Administrative Committee Annual Informational Filing (PTO AC Annual Informational Filing). Attachment B of Schedule TJB/JEA-1 (Highly Sensitive Confidential Information) (Narragansett Precedent Agreement) shows the share allocation by New England EDC.

Q. What are the key aspects of ANE Precedent Agreement?

A. The key aspects of the ANE Precedent Agreement are as follows:

Cost and Cost Caps - [redacted]

[redacted]

Regulatory Approvals - The ANE Precedent Agreement is subject to state regulatory approval. Should such approval not occur, the EDCs may exercise an option to terminate the agreements at no cost to EDC customers.

Other Provisions - The ANE Precedent Agreement requires Algonquin to propose a FERC tariff change to allow capacity-release allocations specific to gas-fired generation. The approach and context of the proposed FERC tariff changes is further described in detail below in Section XIII of this testimony. The ANE Precedent Agreement also provides for a process to adjust the final allocations of volumes associated with the contracts, subject to PUC review and approval.

Right of First Refusal (ROFR) and Discount for Contract Extensions - [redacted]

[redacted]

Sunset Date - [redacted]

Most Favored Nation Provision - [redacted]

[13] This clause is subject to any necessary FERC approvals.

[redacted]

C. Overview of Services, Price Terms and Benefits Under the ANE Agreement

Q. Please identify the price and service terms encompassed in the ANE Precedent Agreement and the Negotiated Rate Agreement.

A. As indicated above, the ANE Precedent Agreement provides for a negotiated rate of [redacted] The ANE Precedent Agreement facilitates access to liquid receipt points and peak-period access to market area storage, injected using summer priced commodity to provide a reliable and flexible delivery service to meet the needs of generators.

Q. Please provide a summary of the ERS Rate Schedule.

A. The ERS Rate Schedule transportation service provides the ability to receive flowing gas at the primary receipt point(s) and to deliver gas to multiple primary delivery points. The Rate Schedule also provides an LNG storage service that the EDCs will use to liquefy gas into storage, and to vaporize liquid out of storage for delivery to generators. The LNG storage facility will be constructed on the strategically located AGT G-system in Southeastern Massachusetts. The LNG service will provide access to supplies on days when flowing supplies from the primary receipt points are fully

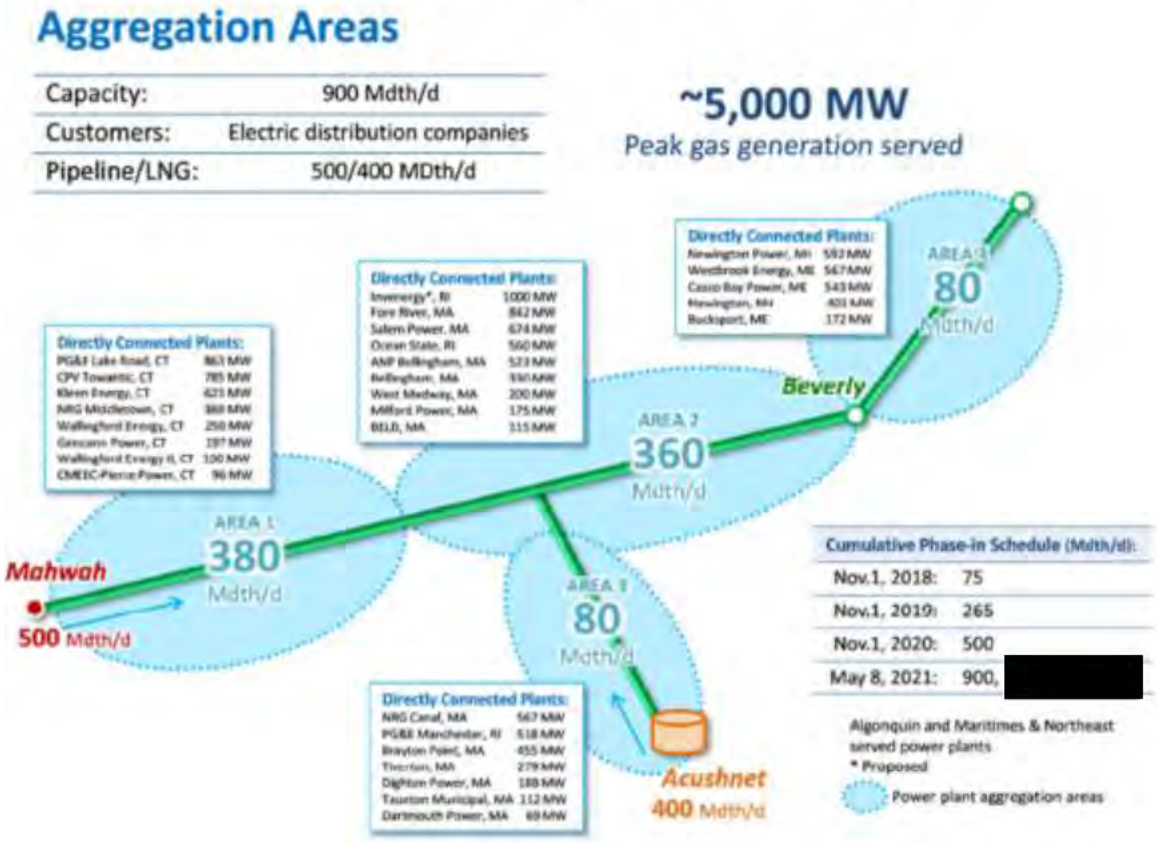
utilized. In addition, the service will provide for hourly no-notice service for both transportation and storage services. The service also includes a ~~"f~~ast start" service that will allow generators to begin taking gas for up two hours prior to having gas nominated with the pipeline. This service will provide generators the ability to vary the amount of gas delivered to their facility on an hourly basis and allow generators the ability to better manage gas supply in order to match the fluctuating demand of the ISO-NE dispatch orders.

Q. Please describe the transportation service component provided in the ANE Service Agreement.

A. The transportation component allows the EDCs to deliver their portion of the 500,000 MMBtu/day of flowing gas available from the upstream pipelines and to deliver their portion of the 400,000 MMBtu/day of LNG deliverability from the regional LNG facility to the generating facilities. The service provides for multiple Primary Receipt points including AGT's Mahwah, NJ; Ramapo, NY; and Brookfield, CT interconnections with upstream pipelines. The storage receipt point will be the LNG facility in Acushnet, MA located on AGT's G-Lateral. For both transportation and storage services, EDCs will have multiple delivery points available. Those delivery points are allocated by four distinct PPAAs as shown in Figure 1 – Access Northeast Project – Receipts and Deliveries by Phase, below, showing the final project volumes.

The Connecticut aggregation area will have 380,000 MMBtu/day of daily deliverability; the AGT G-System aggregation area, which includes Southeastern Massachusetts and Rhode Island, will have access to 80,000 MMBtu/day; the Massachusetts aggregation area will have access to 360,000 MMBtu/day; and the Northern New England aggregation area will have access to 80,000 MMBtu/day.

Figure 1 – Access Northeast Project – Receipts and Deliveries by Phase



There are several generators located within each aggregation area so the capacity will reach any generator within the respective PPAAs on a primary basis. This will ensure

that gas will be available to those generators who utilize the capacity or service on the coldest days of the year.

Q. Please describe the storage service component provided in the ANE Service Agreement.

A. The storage component of the ANE Service Agreement will provide the EDC with the ability to inject into the storage facility during two non-peak periods in order to withdraw from the facility during the winter and summer peak periods. The first injection period will begin April 1 and conclude on July 20 of each year. The remainder of July and all of August, is the summer withdrawal season, which coincides with the ISO-NE peak summer demand for electricity. The second injection period is September 1 through November 30, which will allow EDCs to top off their storage inventories for the winter peak season. The winter withdrawal season runs from December 1 through March 31.

The LNG facility will have the ability to liquefy 54,000 MMBtu/day during the injection season. During the withdrawal season, the facility can withdraw up to 400,000 MMBtu/day. [redacted]

Q. Please describe the no-notice service component provided in the ANE Service Agreement.

A. The ANE Service Agreement provides for hourly scheduling where the EDC or generator has the right to adjust the scheduled quantities to better match the expected use for the day. Any gas that has not been scheduled up to the maximum daily receipt and/or delivery obligation will be reserved by the pipeline. The reserved capacity will be available for the shipper to access additional supplies for intra-day nomination changes.

The no-notice service will allow generators to better match gas utilization with unpredictable dispatch requests from ISO-NE. Many days gas-fired generators are required to run only for part of the day after the pipeline "timely" nomination period has passed and this "no-notice" flexibility will allow those facilities to adjust their gas requirements to fit the load requirements from ISO-NE.

D. Regulatory Approvals Needed

Q. Please describe the FERC regulatory process that applies to pipeline construction projects.

A. Pipeline companies engaged in the interstate transportation and storage of natural gas in interstate commerce must receive a "Certificate of Public Convenience and Necessity" from FERC in order to construct a major project. The regulatory process

includes a comprehensive environmental impact analysis, along with opportunities for public involvement from concerned citizens and state and federal regulatory agencies. FERC is directly involved in evaluating the costs of the projects; the rates to be charged by the sponsor; and compliance with FERC regulations. The U.S. Department of Transportation is involved in safety issues. A specific FERC concern is that the project must be supported by long-term contracts. Therefore, like other interstate pipeline projects, Algonquin will require state-approved, long-term contracts as a prerequisite for their respective FERC approvals.

Q. Will the ANE Project require approval in New England states other than Rhode Island?

A. Yes. The bulk power market in New England is a regional market, with generating facilities throughout the six New England states operating within the oversight of ISO-NE. Within the region, the electric and gas delivery systems are increasingly interrelated with common infrastructure components serving all retail customers in New England so that the electric reliability and cost challenges facing Rhode Island customers are not unique to Rhode Island customers. On December 5, 2013, the Governors of the six New England states jointly acknowledged the need for new natural gas infrastructure serving the New England region, setting in motion a coordinated effort to advance a regional energy infrastructure initiative (*See* Schedule

TJB/JEA-2). The commitment to infrastructure development encompassed within the New England Governors' joint statement is the impetus for the ANE Project. Infrastructure development requires financial commitment through the execution of long-term contracts. Therefore, in the more than two-year period since the joint statement of the New England Governors acknowledging the need for incremental pipeline capacity, efforts have moved forward in each of the New England states to establish a structure for regulatory review of anticipated infrastructure contracts. At this point, all New England states except Vermont have laws or regulations in place, or proposed for effect, that allow for the development of natural gas infrastructure to serve power generation. Consistent with the established regulatory structures, efforts are underway in each of the six states to consider participation and support for infrastructure contracts that will alleviate reliability and cost concerns for New England's retail electric customers. Consequently, this regional solution will require regulatory approvals by New England state jurisdictions in addition to Rhode Island as well as the participation by other EDCs.

Q. Will the PUC's approval of the ANE Precedent Agreement be contingent on participation by other EDCs and on approvals in other states?

A. Yes, effectively. The solution proposed by the ANE Project is sized as a regional solution and will require other New England states and other EDCs to take

responsibility for a proportional share of the costs of the projects, which are necessary to achieve the benefits of lower electricity rates and increased reliability across the New England region. Even with the PUC's approval of the ANE Agreements, Algonquin will not move forward unless and until there is sufficient subscription evidenced through the execution of long-term contracts by EDCs operating throughout New England.

Q. What will happen if the ANE Agreement is not approved in each of the six New England states?

A. The development of regional infrastructure on a coordinated basis is a hugely complex undertaking as the legislative, regulatory and political processes in each state jurisdiction are different. National Grid anticipates that it will take time for all of the concurrent processes to be completed and that there could be challenges that arise through the process. With the high level of complexities involved, it is not possible to predict the outcome or precise timing of infrastructure decisions in each of the six New England states. In this case, National Grid is focused on Rhode Island. Timely approval from the PUC for the Rhode Island load share is critical in moving the entire process forward.

If other approvals do not follow in one or more New England states, Algonquin will need to make a determination whether to proceed with fewer precedent agreements;

reconfigure their respective project and renegotiate the existing precedent agreements; or terminate the project. Given the significant benefits available to Rhode Island customers as a result of project implementation, it will be important for Rhode Island to monitor developments and allow for adaptations and adjustments to achieve project implementation. The ANE Agreement contemplates an expedited process for the PUC, i.e. the issuance of a written order approving or rejecting the contract within 120 days from the filing, per Section 36-31-6(b), should it be necessary to make adjustments to the load share computation to account for final subscriptions levels.

V. Commercial Reasonableness of ANE Agreement

Q. Why, in your opinion, is the ANE Agreement Commercially Reasonable?

A. Section 39-31-3 defines the phrase –ecommercially reasonable" for purposes of the ACES Act as an agreement with terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see in transactions involving regional-energy resources and regional-energy infrastructure. An additional criterion of commercial reasonableness includes having a credible project operation date, as determined by the PUC; however, a project need not have completed the requisite permitting process to be considered commercially reasonable. The ACES Act requires the PUC to determine that the benefits to Rhode Island exceed the cost of the project by determining, based on the preponderance of the evidence, that the total

energy security, reliability, environmental and economic benefits to the state of Rhode Island and its ratepayers exceed the costs of the project.

As described herein, the ANE Agreement is commercially reasonable because the total benefits of the agreement far exceed its costs. Moreover, its terms and pricing are consistent with interstate gas capacity contracts recently approved in the region. Lastly, the ANE Agreement has a credible project operation date, based on the progress to date of federal and state regulatory approvals associated with the ANE Project.

A. <u>Cost Structure</u>

Q. Please describe the cost structure of the ANE Service Agreement.

A. The transportation service has a [redacted]

[redacted]

The storage service has a fixed [redacted]

[redacted]

[redacted]

Q. Please discuss the benefits of the ANE Project and associated ANE Agreement.

A. The increase in incremental capacity and supply associated with the Access Northeast project (900,000 MMBtu/day) will improve electric reliability and mitigate price volatility associated with market-area price spikes caused by gas infrastructure constraints.

A major non-price attribute of the ANE Agreement is the flexibility inherent in the ERS Rate Schedule, which will allow generators to take gas under a ~~"n~~o-notice" service and follow their generation load requirements and avoid scheduling penalties. The unique combination of a regional LNG facility located on the Algonquin G-system in Southeastern Massachusetts provides the pipeline the operational flexibility required to provide this type of service. This is described in more detail below.

Another non-price attribute of the ANE Project is the fact that it is based primarily on an expansion of existing pipeline and does not involve construction in new right of ways. As a result, the ANE Project creates relatively less environmental impact than other alternatives that involve new construction. The project includes the development of a new LNG facility; however, the new facility will be constructed

adjacent to an existing LNG satellite facility at a site with adequate land. The phasing of the project also allows parts of the project to go into service as early as November 2018, pending the development of the LNG facilities.

The ANE Project will be capable of serving the majority of New England's electric gas-fired generation capacity (nearly 70 percent) that is directly connected to an interstate pipeline.[14] This includes 24 power generating facilities that are directly connected to the Algonquin and M&NP facilities, including the 101-mile pipeline from Westbrook, ME to Dracut, MA that is jointly owned by M&NP and Portland Natural Gas Transmission System (PNGTS) (the Joint Facilities). In its RFP, Algonquin identified four plants and that an additional 2,760 MW are expected to be directly connected to Algonquin by 2020.

B. <u>Reliability and Security Benefits</u>

Q. What are the specific fuel-supply issues for New England gas-fired generators that will be addressed by the Access Northeast project?

A. The generation portfolio in the New England region relies substantially on natural gas for electric generation, which is a fuel resource that requires pipeline capacity for delivery. Because there is no indigenous gas storage capacity in the region, gas typically flows hundreds of miles from the production areas and storage fields to the

[14] The Access Northeast project will be capable of providing service to those generating facilities directly connected to the Algonquin and M&NP pipelines, including those power plants directly connected to the Joint Facilities of M&NP and Portland Natural Gas Transmission System.

New England market region, which ISO-NE has described as a "just-in-time" fuel delivery system.[15]

Demands on these supplies are greatest during the coldest periods of the year when heating requirements are at their highest level and the gas LDCs are utilizing their firm pipeline capacity and on-system LNG peaking facilities to meet firm gas customer demand. ISO-NE gas-fired generation is often called on short notice to dispatch power during peak gas demand periods to meet the hourly variations in power load throughout the day, which have coincident peaks during the mornings and evenings. Gas-fired generators have the ability to start up quickly to meet unexpected load fluctuations on the grid. The ISO-NE depends heavily on this capability to achieve reliability and it is anticipated that the ability to start and ramp up quickly will be even more important as new intermittent resources such as wind and solar continue to be added to the system. However, in order for these generators to provide this service, the generators must have access to gas supplies on short notice and for short durations. It should also be noted that there are numerous generation plants that have been specifically designed as "peaking" facilities and that run only a few hours each day to assist the regional system operator in managing the hourly power load fluctuations. This creates a difficult situation because gas is often needed in real-time on short notice but the normal "day ahead" trading and scheduling process does not

[15] http://www.iso-ne.com/nwsiss/pr/2013/2013_winter_outlook_press_release_final.pdf

accommodate these short term variations in load. At times, these generators may not be able to perform on such short notice due to the unavailability of firm pipeline capacity or insufficient fuel supply. If these generators can acquire gas, those opportunities exist only in the secondary market on an intra-day basis, which typically involves more expensive fuel sources. In most cases, the necessary gas and pipeline capacity has already been allocated to shippers who own the capacity and therefore it is not available in the secondary market.

In FERC Docket No. RM14-2-000,[16] ISO-NE provided FERC with information showing the number of times the gas-fired generators day-ahead market commitments were reduced as a result of the inability to acquire natural gas. Numerous generators and regional system operators attempted to remedy these issues by making changes to the timing of the Gas Day. The final rule did not change the Gas Day scheduling requirements on the basis that there was not sufficient evidence and industry consensus to indicate that changing the Gas Day scheduling requirements would resolve these issues. Some changes were made to portions of the nominations and scheduling rules in an attempt to accommodate some of these unique gas-fired generation requirements. However, the fundamental problem arising from the fact that gas-fired generators do not hold firm pipeline capacity for their fuel requirements,

[16] FERC, 18 CFR Parts 157, 260, and 284[Docket Nos. RM96-1-038 and RM14-2-003; Order No. 587-W issued October 16, 2015.

which is the root cause of the price volatility and reliability concerns in New England, was not addressed.

Q. Please describe the type of gas service that would be tailored to the unique characteristics of gas-fired generation demand on the natural gas pipelines in New England.

A. Combining primary firm pipeline capacity of scale from liquid supply areas with local domestic peaking supplies/facilities and associated on-site storage to serve the dynamic load requirements of New England gas consumers is a well-established practice of the LDCs.[17] Standard pipeline services require substantially even hourly flows of supplies, with the matching of receipt quantities with delivery quantities. As gas-fired generators acquire gas from pipelines to serve their requirements, these facilities will find that portfolio resources providing access to LNG vaporization and storage will likely be required to serve their highly variable requirements.

A physical gas service that could provide generators with the ability to take gas prior to actually having nominated or scheduled gas would be the ideal service to accommodate the hourly, real-time, highly variable requirements of power generation. In order to provide this service, pipelines need to have access to variable sources of supply (such as an LNG facility or an underground storage facility) that they can

[17] *See*, *e.g.*, Yankee Gas Services Company, Connecticut Public Utility Regulatory Authority Docket 14-10-01, NSTAR Gas Company, D.P.U. 14-63 (2015).

control. Some pipelines currently offer ~~"n~~o-notice" services that can be nominated later in the day to accommodate changes in load requirements for shippers on the pipelines, but often a generator is called to generate power with little notice and may not be able to acquire gas for several hours. A ~~"f~~ast-start" service provides this unique type of service by combining the primary firm pipeline capacity to the generator's plant with a regional storage facility that can deliver gas in a ~~"r~~eal-time" manner allowing the pipeline to operate in a balanced state, while accommodating the needs of the generator to take gas prior the generator's ability to have the gas actually delivered to the pipeline.

Q. Please describe the benefits of having a regional storage facility sited in New England.

A. The pipeline capacity in the region is at or near capacity on nearly every day of the year in New England and particularly during the winter period, as explained in the testimony and schedules of Mr. Wilmes. During these times, the LDCs are often utilizing their on-system LNG facilities, which were filled during the summer period to meet the daily and hourly fluctuations in load. A local LNG facility would be able to liquefy domestically produced gas from the Marcellus region at relatively lower costs when gas prices are typically lower during the off-peak summer period. This would insulate the facility from the volatility of world LNG markets as the cost of

imported LNG for summer refills is more reflective of winter prices. The facility's proximity to generators allows for the "fast-start" capability where the generator can take gas prior to nominating it from a receipt point. These facilities also provide a critical reliability function as the facilities can support a portion of the loads during any potential disruptions to the pipeline systems, which are rare but can and have occurred. In these circumstances, the power generation fleet would have access to a strategically located market area LNG facility with a scale sufficient to impact supply and demand imbalances.

C. Environmental Impacts

Q. Has National Grid analyzed the environmental impacts of the ANE Project?

A. Yes. The Company is providing the testimony of Mr. Andrew Byers from Black & Veatch (Exh. ACB) describing the environmental impacts of the ANE Project. The Black & Veatch analysis indicates that, in comparison to the reference case, the addition of the ANE Project would reduce NOX emissions by approximately 18,000 tons (16% reduction), SO2 emissions by approximately 35,000 tons (26% reduction), and CO2 emissions by approximately 6,000,000 tons (0.86% reduction) in the New England region.

D. Economic Benefits

Q. Has National Grid performed an economic net-benefits analysis of the ANE Agreement?

A. Yes. Black & Veatch has performed a long-term economic net-benefits analysis of the ANE Project in order to appropriately consider and compare the resulting wholesale electricity market cost savings expected to be realized for EDC customers to the project costs those same customers would be required to support under the Proposed Agreement.

Q. Please provide a summary of the results of that net-benefits analysis.

A. As further described and detailed in the testimony and supporting exhibits of Mr. Wilmesof Black & Veatch, the pipeline capacity constraint-relieving ANE Project would generate significant cost savings to electric customers in New England by reducing the price of natural gas available to the region's power generators, and thus the wholesale and retail electric energy prices in the New England region. Region-wide, the ANE Project is projected under normal weather conditions to result in wholesale energy market cost savings for New England retail electric customers of approximately $1.6 billion per year on a levelized basis from 2019 through 2038. Approximately $141 million of those benefits would be expected to accrue to electric customers in Rhode Island. After accounting for the costs of the ANE project, the

corresponding net-benefits to electric customers in New England are projected to be over $1.1 billion per year, and produce a total net present value of $10.2 billion. For electric customers in Rhode Island, the levelized net-benefits are projected to be over $108 million per year, and produce a total net present value of approximately $1 billion.

Q. Are there additional economic benefits associated with the enhanced reliability expected to result from the ANE Project?

A. Yes. While the benefits of enhanced reliability are difficult to measure exactly and thus quantify as a specific dollar value, one can look to estimates of the value of lost load (VOLL) from previous studies for some guidance. VOLL is the value consumers place on an undelivered MWh of electrical energy. The benefits of maintaining a reliable bulk power system, though difficult to quantify exactly, are nevertheless real. A research paper entitled the "Value of Lost Load" is informative.[18] There, authors Peter Cramton and Jeffrey Lien of the University of Maryland note that the economic literature justifies estimates of VOLL, on a $/MWh basis, of $2,400 to $20,000. Based only these estimates of the VOLL, and ISO-NE's recent estimate of 4,220 MW of natural gas-fired generating capacity at risk of not being able to get fuel when

[18] Value of Lost Load, University of Maryland, February 2000, http://www.isone.com/committees/comm_wkgrps/inactive/rsvsrmoc_wkgrp/Literature_Survey_Value_of_Lost_Load rth.

needed this winter,[19] the additional reliability value of reducing the existing gas pipeline capacity constraints and preventing a loss of load of 4,220 MW for just two hours could be almost $170 million.

VI. Evaluation and Procurement Process

A. Procurement Process

Q. Did National Grid commence the process to identify an interstate delivery infrastructure solution prior to the enactment of the ACES Act?

A. Yes, absolutely. Commencing with the New England Governors' joint statement of commitment to a cooperative regional initiative in December 2013, National Grid has been actively engaged in an effort to identify a solution to the market imbalance of natural gas supply and demand, with particular reference to electric generation. The joint statement of the New England Governors raised the possibility of facilitating the development of gas pipeline capacity infrastructure through a collaborative process involving ISO-NE and the New England State Committee on Electricity (NESCOE) (Schedule TJB/JEA-2).

By letter dated April 22, 2014, Northeast Utilities (the predecessor company to Eversource Energy), National Grid and UIL Holdings outlined an approach whereby

[19] Winter 2015/2016: Sufficient Power Supplies Expected to be Available Natural gas pipeline constraints continue to challenge reliable operations Holyoke, MA (December 1, 2015).

electric distribution companies would, under certain circumstances, consider entering into long-term contracts with interstate pipeline companies for new firm gas transportation capacity. The approach acknowledged that, in addition to the construction of new pipeline capacity, solutions that include increased availability of domestic LNG supplies, gas storage and no-notice pipeline services should be explored in order to address the central issue of electric reliability and retail price volatility for electricity. Consistent with this outlined approach, the process commenced by the New England Governors' joint statement continued in the interests of identifying a solution that would support electric generation and facilitate the attainment of increased grid reliability and retail price stability.

Q. How did these efforts progress in furtherance of the goals outlined in the New England Governors' joint statement?

A. Throughout 2014, efforts that commenced with the issuance of the New England Governors' joint statement continued evolving with EDC involvement and within the context of a growing recognition that the EDCs would need to take the initiative to underwrite the construction of incremental pipeline capacity for the New England states. Early in this process, the entities involved in the effort, including National Grid recognized the need to follow certain protocols to ensure that:

Any eventual solicitation and evaluation process would be conducted in a fair, transparent and competitive manner;

- All laws, regulations, rules and standards and codes of conduct would be observed
- All potential bidders would be treated equally;
- No potential bidder would receive preferential treatment or non-public information not available to other potential bidders, enabling it to gain an unfair advantage; and
- Efforts of the EDCs in the solicitation process would not create any actual or apparent conflict of interest to the extent that the EDCs (or their affiliates) may seek to submit a proposal and may participate in the solicitation and/or evaluation of proposals.

National Grid affiliates formally identified a cross-functional group of employees to support the business development of potential gas infrastructure projects (Business Development Team). In parallel, National Grid regulated electric utilities and its affiliated gas utilities identified a group of employees to support the evaluation of the various New England gas infrastructure initiatives (Evaluation Team).

Q. What are the specific codes of conduct procedures that the Company employed for business development and evaluation and procurement activities?

A. In conjunction with the establishment of the business development team and effort and of the evaluation and procurement effort, National Grid recognized that it would need to establish an internal framework to assure the transparency and fairness of the process. This framework, through standards of conduct, generally requires fairness and

transparency in affiliate transactions. These standards also generally prohibit preferential treatment and/or sharing of confidential or competitively sensitive information among transacting affiliates.

To avoid an actual or apparent conflict of interest regarding the business development effort and the activities and obligations of the National Grid distribution companies with respect to the New England gas infrastructure initiatives, National Grid established Standard of Conduct Guidelines, that were similar to the Utility Standards of Conduct developed for the Regional Clean Energy RFP. As is the case with the Utility Standards of Conduct, written certification is required from each team member acknowledging he/she will follow and be bound by the Standards of Conduct Guidelines. Questions regarding compliance with the Standards of Conduct Guidelines are directed to National Grid Compliance Counsel, who maintains electronic copies of all signed certifications and updated team rosters.

Q. Were Company employees provided with any training on the applicable standards of conduct guidelines?

A. The Standards of Conduct Guidelines are relatively intuitive but team members are encouraged to ask questions and Compliance Counsel has fielded a number of questions. The Evaluation Team received training on the Standards of Conduct Guidelines by Compliance Counsel. Compliance Counsel circulated the team rosters

and Standards of Conduct Guidelines to each team member and has kept the team leads up to date with roster changes. Compliance Counsel has also conducted internal meetings with management groups to review the standards. Compliance Counsel has followed up by circulating team rosters to all participating employees.

Q. Can you provide more detail regarding the development of the Access Northeast Project and the process that the Company followed to assure that contract negotiations were conducted on a transparent "arms-length" basis?

A. Ultimately, Narragansett and its Massachusetts electric affiliates, Eversource Energy and Spectra Energy announced plans to develop incremental capacity on Algonquin's Access Northeast project as part of a joint venture. Planning for the Access Northeast project was conducted by the Business Development Team which was kept separate from the Evaluation Team. The Business Development Team was engaged in the planning and development of the Access Northeast project, and the Evaluation Team was separately engaged in the assessment of portfolio objectives and identification and evaluation of resource alternatives and net benefits associated therewith. The National Grid Evaluation Team began negotiating precedent agreements with Spectra to support the Access Northeast project. [20]

[20] As noted herein, the Company's Massachusetts affiliates entered in precedent agreements with both Algonquin and Tennessee as a result of the RFP. However, the developer of the Tennessee Northeast Direct (NED) Project suspended work on the project in late April.

Q. How far did the process to negotiate precedent agreements with ANE during 2015?

A. Between April 2015 and October 2015, the teams involved in the contract negotiations made progress on a number of key issues. Throughout this period, National Grid also monitored industry developments regarding other potential alternatives and participated in pipeline open seasons for Access Northeast. Negotiations on the ANE Contract were not concluded and, in fact, were suspended as a result of the RFP jointly issued by Eversource and National Grid on October 23, 2015.

Q. How did the DPU's decision in D.P.U. 15-37 and the ACES Act affect National Grid's efforts to put forth a contractual commitment to interstate pipeline capacity for the benefit of electric customers?

A. Based on the DPU's October 2, 2015 findings in D.P.U. 15-37, wherein the DPU concluded that it had authority to review long term contracts for gas capacity executed by the EDCs for the benefit of electric customers, National Grid decided that an RFP process would be useful in confirming the range of alternatives meeting the criteria for relief of electric reliability and retail price volatility concerns. Therefore, National Grid immediately commenced efforts to develop an RFP for resource alternatives to be jointly issued by Eversource and National Grid.

Q. When was the RFP issued?

A. On October 23, 2015, the Company issued the RFP to solicit proposals for interstate capacity/gas supplies to further the goals of reduction of the cost of electricity and increasing the reliability of the New England electric system to benefit electric distribution customers. Schedule TJB/JEA-3. On that same date the Company, in coordination with Eversource, issued a similar request for proposals on behalf of its Massachusetts EDCs – Massachusetts Electric Company and Nantucket Electric Company. Consistent with the policy statements articulated in ACES, the RFP noted to potential bidders that the EDCs would be required to demonstrate that any proposed contracts and strategies for reducing the costs of electricity for their electric customers are the most appropriate alternative of the range of alternatives that may be leveraged to achieve reduced electricity costs while ensuring reliability for customers. Accordingly, the RFP requested proposals for pipeline expansion projects, LNG supply alternatives, and regional storage projects for that purpose. The RFP was issued to six interstate pipeline companies serving the New England region and two LNG providers. The RFP was also posted on each EDC's website. Bid questions were received October 30, 2015 with bids due November 13, 2015. All bid questions were received and answered in written form to all potential participants. The RFP issued on October 23, 2015 is provided herewith as Schedule TJB/JEA-3.

Q. What information were bidders required to include in any bids responding to the RFP?

A. Each proposal was required to include the following information: (1) delivery and receipt locations; (2) service type and operational flexibility; (3) quantity; (4) price; (5) contract term and renewal rights; (6) a proposed contract/precedent agreement; (7) any existing tariffs and pro-forma service agreements; (8) documentation of experience with development and management of natural gas resources; (9) a list of related regulatory approvals and the timing of each; (10) audited financial statements, annual reports and credit ratings; (11) business conditions and financial reports, and (12) disclosure of any pertinent legal issues and potential conflicts of interest. Schedule TJB/JEA-3, at 2-6. Specifically, the following key criteria were set for bidding parties:

1. Regional Scale: Project solutions were required to have a regional scale, ranging from a minimum of 500,000 MMBtu/day to a maximum of 2,000,000 MMBtu/day.
2. Delivery and Receipt Points: Identification of specific receipt and delivery points was a critical prerequisite for conforming bids. Receipt points are critical to ensure that the point of purchase allows access to a long-term liquid supply. Delivery points must be primary firm and delivered to meter-specific ISO-NE generation facilities in multiple load zones. The receipt and delivery points are critical

components of a solution because if the gas is not available and able to get to where it is needed on the coldest days, there would be no incremental reliability benefit nor ability to reduce the cost to customers.

3. Service: Flexible service offerings providing hourly flexibility in a cost effective and reliable manner would be beneficial to electric generators and should be an element of the solution to assure that the resource alternative is economically and operationally attractive to generation facilities.
4. Price: Each responder was required to provide all relevant information and cost breakdowns to allow for a comparison of options.
5. Contract Terms and Renewal Rights: Contract terms were required to be for a minimum of 15 years and a maximum of 20 years.
6. Contract/Precedent Agreements: Each bidder was provided a sample/draft precedent agreement to use as a guideline for the contract terms acceptable to the EDCs. The bid guidelines also allowed bidders to rely on a precedent agreement previously tendered to an EDC as part of negotiations ongoing prior to the issuance of the RFP, or to provide a precedent agreement that was previously accepted by a New England regulatory jurisdiction. Specific to LNG imports, the EDCs additionally requested respondents remove the country risk of origin and LNG shipping risk from the force majeure provisions. This was necessary to

ensure reliability over the long term and to mitigate known imported LNG supply risk factors.

7. Service Agreements/Tariffs: Bidders were required to submit Service Agreements and all associated Tariffs.
8. Experience and Expertise: Bidders were required to specify their experience with developing and managing natural gas resources. For the EDCs, this element is vital as the process to develop incremental resources is very complex and requires unique and specific experience to succeed. The interests of customers will not be served where time and resources are spent without timely in-service dates. Due to the nature of the market imbalance, time is of the essence and therefore, experience and expertise is a critical prerequisite.
9. Approvals: Bidders were required to list all necessary approvals that would be necessary to complete the proposed project/facilities.
10. Financial Statements/Business Reports: Bidders were required to submit financial and business-related information to demonstrate that their proposed project is viable and can be carried out to completion. Preference was indicated for credit ratings of investment grade or above with a positive outlook.
11. Legal Matters/Conflicts: Bidders were required to discuss and identify any legal matters and/or conflicts of interest that the EDCs would need to be aware of.

VII. Analysis of Resource Alternatives

A. Analysis of Responses to RFP

Q. When were bids received and how did the Company evaluate such bids?

A. The Company received proposals on November 13, 2015 in response to the RFP. The Company retained the assistance of Black & Veatch to evaluate the responses to the RFP. The Company provided all material to Black & Veatch to enable them to evaluate each bid against the requirements in the RFP. Black & Veatch preformed a two-step process in the evaluation of the bids received. In the first step, a screening analysis was undertaken to determine whether the respective bid conformed with the requirements and objectives of the RFP. Several bids were eliminated from consideration at this stage due to the fact that the bids were "non-conforming" in terms of satisfying the threshold bid criteria. For example, certain bids were eliminated for failure to meet the minimum size to implement a regional solution. The projects that remained after this step included the Tennessee NED project[21] and the Spectra Access Northeast project. The second step of the process involved a quantitative analysis of the cost of the projects to the EDC customers and benefits to the region in the form of lower electricity prices. In this quantitative analysis Black & Veatch used an Integrated Market Modeling process to generate wholesale market prices for natural

[21] The Company's Massachusetts affiliates entered in precedent agreements with both Algonquin and Tennessee as a result of the RFP. However, the developer of the Tennessee NED Project suspended work on the project in late April.

gas and wholesale Locational Marginal Prices at key New England transmission zones to determine the net benefits to the region and ultimately National Grid's customers. The details of the screening process of the bids, performed by Black & Veatch, are provided in the testimony of Mr. Porter. The quantitative analysis of the qualifying bids was performed by Black & Veatch and is provided in the testimony of Mr. Wilmes.

Q. Please explain whether Black & Veatch subsequently performed quantitative analysis of LNG bids submitted in response to the RFP, and summarize the results of such analysis.

A. As a result of its coordination and consultation with the Rhode Island Office of Energy Resources and the Rhode Island Division of Public Utilities and Carriers pursuant to the ACES Act, the Company subsequently asked Black & Veatch to also perform quantitative analysis of LNG bids received from GDF Suez and Repsol. While these bids had been determined to be ~~"n~~on-conforming" in terms of satisfying the threshold bid criteria, Black & Veatch agreed to perform the quantitative analysis of these bids using the same Integrated Market Modeling process used to determine the net benefits for electricity customers of the NED and ANE projects. The results of this additional quantitative analysis, as provided in the testimony Mr. Wilmes reveal the projected net

benefits of the GDF Suez and Repsol LNG bids to be less than 49% and 22%, respectively, of the projected net benefits of the proposed ANE project.

B. Energy Efficiency Alternatives

Q. Please explain whether the Company considered energy efficiency as an alternative to the Proposed Agreements.

A. The testimony of Jeremy J. Newberger, Manager for Energy Efficiency Policy and Evaluation for National Grid's Rhode Island energy efficiency programs, discusses the fact that Rhode Island is an industry leader in the supply of Energy Efficiency (EE) with nationally recognized programs that far exceed the range of programs implemented in other state jurisdictions. Mr. Newberger's testimony further discusses that given this broad scale of EE deployment, EE cannot suffice to resolve the market imbalance of supply and demand due to the scale of natural gas capacity needed in New England. There is simply no reasonable or feasible implementation of EE that would reduce the demand for natural gas in a quantity to offset the need for incremental gas capacity.

C. Renewable Alternatives

Q. Please explain whether the Company considered renewable resources such as wind and solar as alternatives to the Proposed Agreements.

A. National Grid recognizes that renewable resources will continue to play important roles in helping New England satisfy its energy needs while also meeting its clean energy and carbon reduction goals, including the Massachusetts Global Warming Solution Act emissions reduction targets. As ISO-NE recently reported:

> By the end of 2014, 800 MW of wind power (nameplate capacity) had been installed in the region, which produced nearly 1% of the region's electricity that year. By 2015, developers had proposed 4,000 MW of additional wind power. Furthermore, ISO studies have shown that New England has vast wind power potential that could generate nearly a quarter of the region's electricity under high wind penetration scenarios (up to 12,000 MW of onshore and offshore wind power resources).3 By the end of 2014, 900 MW of solar photovoltaic (PV) resources (AC nameplate capacity) had been installed in the region, and ISO New England's solar PV forecast projects the region will realize nearly 2,500 MW by 2024.[22]

However, it is well recognized that such wind and solar resources suffer from the inherent intermittency and variability characteristics which are unfavorable to the ability of their full production potential to be relied upon in addressing infrastructure and related resource adequacy concerns such as those at issue in this proceeding. As ISO-NE has stated:

[22] ISO-NE's "The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future" Revised Discussion Paper of October 2015.

> The less frequently a variable resource is expected to operate during a year, the less the resource contributes to ensuring reliability. Thus, a 100 MW wind resource which operates 20% of the time, when the wind blows, contributes less to meeting capacity needs than a 100 MW combined-cycle generator that operates 80% of the time, and on demand. The total quantity of resources needed should be expected to grow as more variable and renewable resources are added to the system; these resources typically make contributions to reliability that are only a fraction of the value of their nameplate capacity. For this reason, variable resources like wind have their capacity severely discounted when counted toward meeting the ICR.[23]

It might be assumed that a solution to the issue identified above could simply be achieved by buying four or five times the amount of wind, ignoring the question of whether that would be technically and/or economically feasible. However, if the wind is not blowing and/or the sun is not shining when those resources might be most needed, such as on a cold winter evening when unresolved pipeline capacity constraints are limiting the availability of gas-fired generators, it is clear that this is not an adequate solution.

Furthermore, as ISO-NE has explained:

> The expected future increase in renewable resources, and the consequent reduction in energy prices, will put increased pressure on existing baseload units and any technology that is highly capital intensive or has high fixed costs. This financial pressure will likely cause them to retire sooner than they otherwise would.[24]

[23] ISO-NE's "The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future" Revised Discussion Paper of October 2015.

[24] ISO-NE's "The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future" Revised Discussion Paper of October 2015.

As demonstrated by the recent capacity additions to the system, for the foreseeable future most of the new entry replacing such retiring resources will be gas-fired resources, which adds to the need to resolve the region's natural gas deliverability constraints as soon as possible.

Q. Please explain the Company's consideration of additional large-scale hydro resource imports and associated transmission as a potential alternative to the Company's Proposed Agreement?

A. National Grid is currently participating as a soliciting party in a multi-state Clean Energy RFP[25] investigating the potential to cost-effectively achieve new incremental clean energy for New England, including additional clean energy from large hydro resources in the regions to the north via investments in new transmission interconnections as necessary. There is little question as to the valuable role large hydro imports must play in helping the region to achieve its long-term clean energy goals, and the reliability and economic benefits they provide simply by enhancing the diversity of supply. Moreover, such resources can play an important role in complementing and enabling investments in other renewable resources such as wind and solar. The characteristics of large hydro position it well to be used as a balancing resource to help address the previously noted concerns with the intermittency and variability of production from these other renewable resources.

[25] https://cleanenergyrfpdotcom.files.wordpress.com/2015/11/clean-energy-rfp-final-111215.pdf.

However, a greater reliance on the imports of energy from large hydro resources is not an alternative that would eliminate the need for the natural gas pipeline capacity expansions supported by the Company. While such imports as they occur throughout the year can certainly provide the benefits discussed above, they cannot be expected to resolve the pipeline constraints which are most severe and of most concern to New England during the winter months. It is during that same period each year when the capacity of hydro resources such as those located in the Hydro Quebec control area may be most needed to meet that area's winter peaking electricity demand, and thus perhaps the least available to reliably serve the needs of the New England system. Even if the quantities of additional hydro resources and required transmission infrastructure were assumed to be cost-effectively achievable to the levels necessary to address the growing inadequacies of natural gas infrastructure for delivery into the region, which ISO-NE has recently stated is ~~—~~inadequate to meet the demand for gas for both heating and power generation" in the coldest weeks and is currently placing ~~–~~over 4,000 megawatts (MW) of natural-gas-fired generating capacity at risk of not getting sufficient fuel on any given day,"[26] system operational reliability concerns would remain. These concerns are demonstrated by a few examples from recent winters. On December 4th of 2014, ISO-NE was suddenly required to implement

[26] ISO-NE ~~–~~Winter 2015/2016: Sufficient Power Supplies Expected to be Available Natural gas pipeline constraints continue to challenge reliable operations" Holyoke, MA—December 1, 2015.

Operating Procedure #4 (OP4)[27] to manage a deficiency in operating reserves which lasted for several hours when ~~–~~Hydro-Quebec TransEnergy (HQ) curtailed 2,005 MW into New England … due to the loss of two major 735 kV transmission lines in Quebec,"[28]and on December 14th of 2013, ISO-NE again was forced to implement OP4, largely as a result the unexpected loss of imports, with the ISO reporting that ~~–~~the majority of curtailments were experienced on the Hydro Quebec Interfaces due to loads in HQ running well over forecast."[29]

Moreover, the most recent Forward Capacity Market (FCM) auction results have revealed a decrease in the level of imports from the Hydro Quebec control area taking on capacity supply obligations and committing to perform as capacity resources available to New England. Whether these recent results should be assumed to reflect a long term expectation of the willingness or ability of large hydro from the north to commit its capacity to New England and meet the year round performance obligations remains to be seen.

In sum, despite the potential value and benefits to be realized from additional clean energy imports, the Company does not consider reliance on such imports a reasonable

[27] ISO-NE Operating Procedure No. 4 (Action During A Capacity Deficiency), establishes criteria and guides for actions during capacity deficiencies, as directed by ISO-NE and as implemented by ISO-NE and the Local Control Centers.

[28] ISO-NE Dec 9, 2014 Memo to NEPOOL Markets Committee and NEPOOL Reliability Committee.

[29] ISO-NE COO Report to the NEPOOL Participants Committee on January 10, 2014, page 8.

alternative to its proposed approach of supporting the pipeline capacity expansions most directly addressing the significant existing gas infrastructure inadequacies.

Q. Please explain whether the Company performed any additional analysis to examine the sensitivity of the projected ANE net benefits to potential additions of large scale clean energy resources to the system.

A. During its coordination and consultation with the Rhode Island Office of Energy Resources and the Rhode Island Division of Public Utilities and Carriers pursuant to the ACES Act, the Company was asked by these agencies to perform such additional analysis. Specifically, the Company was asked to have Black & Veatch run its quantitative analysis of the ANE project against two new reference cases. It was requested that the first new reference case (Sensitivity Reference Case A) assume the existence of a new large-scale hydropower resource, with associated transmission infrastructure, reflective of the 1,090 MW Northern Pass project bid in response to the multi-state Clean Energy RFP. It was requested that the second new reference case (Sensitivity Reference Case B) assume the existence of not only a Northern Pass project, but also the existence of a new large-scale wind resource, with associated transmission infrastructure, reflective of the 1,200 MW Maine Renewable Energy Interconnect (MREI) project also proposed in response to the Clean Energy RFP. Black & Veatch performed this requested additional analysis, and the results, as

provided in the testimony Mr. Wilmes reveal that the proposed ANE solution is projected to generate significant long-term net benefits for electric consumers across all of the studied reference cases.

VIII. Maximizing Value Received by Customers

Q. Would you please explain how National Grid will administer the release of natural gas pipeline capacity and LNG to the electric market so as to maximize reliability and price-relief benefits for electric customers?

A. National Grid has collaborated with Eversource to develop an "Electric Reliability Service Program" (ERSP), which will utilize a Capacity Manager to administer the release of contracted gas capacity to the electric generation market. The ERSP is contemplated to be a state-approved program, and the details of the proposed ERSP are provided in Schedule TJB/JEA-4. Conceptually, an agreement between participating EDCs and the Capacity Manager would facilitate the transfer of procured capacity to electric generators on a priority basis to ensure reliability and promote liquidity. The priority release enhances reliability to the region as the generators will have access to the highest level of service provided by interstate natural gas pipelines in the form of primary firm transportation capacity. The EDCs are providing this priority of service structure to match natural gas infrastructure specifically designed to serve the power generation with its dynamic demand profile.

Under the agreement, the Capacity Manager would aggregate the assets owned by the EDCs and would be directed by an EDC Working Committee (EDC-WC) comprised of representatives of each EDC that has contracted for gas infrastructure assets as part of this program. The EDC-WC would directly report to an EDC Executive Committee (EDC-EC) comprised of one executive from each EDC, who will make all final decisions regarding asset management. The EDC-EC will coordinate with regulatory authorities annually to report on the program activity. The agreement would stipulate that the Capacity Manager is to make capacity available to generators prior to releasing any capacity to the secondary market. These parameters are essential to ensure that reliability and other benefits are achieved. These parameters also emulate in many respects the manner in which a gas LDC provides its customers with a reliable and reasonable cost supply. The capacity would be released to generators in a similar fashion as is currently allowed under FERC rules, but under FERC-approved tariff provisions that would enable the Capacity Manager to accomplish this service priority for generators similar to FERC-approved release rules related to LDC retail unbundling programs.

Specific controls, policies and procedures would be developed to ensure appropriate management controls are in place for the Capacity Manager to effectively administer the capacity and LNG to improve fuel deliverability to generators. Those EDCs who have affiliated Gas LDCs are highly experienced in developing and operating under

such controls, policies and procedures and will leverage this experience as part of administration of this program. Again, a more detailed explanation of the process is provided in Schedule TJB/JEA-4.

Q. Can you please explain how the Capacity Manager will be selected?

A. The EDC-WC will conduct a competitive bidding process with a request for proposals to select a Capacity Manager. The Capacity Manager will not be allowed to have any conflicts of interest that could distract from or conflict with their requirement to serve the EDCs' interests. The EDCs envision a model that would involve a single purpose entity that performs the intended services with very specific roles and responsibilities. The Capacity Manager's responsibilities would include releasing the capacity in a manner consistent with the EDC guidelines, which include effectively releasing capacity to the generators to ensure reliability and maximizing the credits received from the releases of capacity to help offset the cost of the EDC capacity. The Capacity Manager would also report on results to the management committee. The Capacity Manager would be compensated in the form of a fixed fee.

Q. Can you please explain how the revenues generated by the sales of capacity or LNG will be returned to customers?

A. The revenues generated by releasing the capacity would be credited back to the EDCs' customers net of the administrative costs required to compensate the Capacity

Manager. Capacity will be released to the highest price bid by generators in the competitive process for longer term releases (i.e., greater than one month) or during the ~~"r~~real-time" bidding process for shorter term transactions. LNG would be sold by the EDCs to generators at market-based prices and will be reflective of an objective index such as the Daily AGT City Gate index. The margin from the LNG sales will be defined as revenue less the cost of the LNG, which will include the commodity price of gas injected plus all of the variable charges associated with injecting, transporting, storing and withdrawing the LNG from the storage facility.

The revenues collected from capacity releases and the margins from LNG sales would then be credited to the EDC customers in a reconciling mechanism in which revenue and net margin offset the costs of the capacity. Each EDC would receive a share of those net dollars proportionate to their respective share of the total pipeline (and LNG, if applicable) capacity under this program. These values in the gas market will fluctuate over time.

Q. What are the "FERC-approved" release rules that you referred to earlier?

A. As part of its Order No. 636 program for unbundled open access natural gas pipeline transportation, FERC adopted capacity release regulations that allow firm shippers to release their capacity entitlements to replacement shippers. The regulations were designed to assure a transparent and non-discriminatory allocation of pipeline capacity

to those who valued it the most. Thus, with limited exceptions, the regulations excluded preferential treatment for replacement shippers by requiring that shipper offers to release capacity be posted on a pipeline's internet website and that offers below the pipeline's maximum lawful rate be subject to competitive bidding. The initial limited exceptions/exemptions to the competitive bidding requirement were for short-term releases of thirty-one (31) days or less and releases at a pipeline's maximum lawful rate.

These generic exemptions to the competitive bidding requirement were expanded under FERC Order No. 712 to include capacity releases to asset managers and capacity releases in connection with state retail competition programs.[30] The pipeline on behalf of the EDCs would need to seek FERC approval for priority release of capacity to electric generators as the EDCs are proposing here.

Q. Has FERC previously recognized that flexibility in its capacity release regulations might be appropriate for the public interest purpose of assisting natural gas-fired generators in obtaining access to firm transportation service?

A. FERC has declared itself to be open to considering deviations from its capacity release regulations and/or the shipper-must-have-title rule on a case-by-case basis, where it is shown to be in the public interest, and FERC has acknowledged such public interest in, and provided the specific example of, assisting natural gas-fired generators in

[30] Promotion of a More Efficient Capacity Release Market, Order No. 712, 123 FERC ¶ 61,286 (2008) (Order No. 712), order on reh'g, Order No. 712-A, 125 FERC ¶ 61,216 (2008), order on reh'g, Order No. 712-B, 127 FERC ¶ 61,051 (2009).

obtaining access to firm transportation service in a transparent and not unduly discriminatory manner.[31]

Q. How will EDCs manage any FERC approvals needed to effectuate the ERSP?

A. In accordance with the Proposed Agreements, Algonquin is required to seek authorization from FERC that would allow the Company to release pipeline capacity to electric generators on a preferential basis. In the event that such authorization is not obtained the Proposed Agreements allow the Company to terminate without liability. Since this is a tariff filing approved by the FERC, the EDCs have been in discussions with project developers on the terms of the capacity-release program, the main elements of which are contained Schedule TJB/JEA-4, referenced above. Final approval of the ANE Agreement would be conditioned on the approval of the tariff provision by FERC consistent with the state regulatory approvals of EDC precedent agreements. FERC has already recognized that granting retail gas marketers priority access to released capacity under state retail competition programs is in the public interest and has approved such priority access; the ERSP will accomplish similar goals.

[31] Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, Order No. 809, 151 FERC ¶ 61,049 (2015) Par. 146. *See also* Georgia Pub. Serv. Comm'n, 107 FERC ¶ 61,024, at P 36 (2004), reh'g granted in part, denied in part, 110 FERC ¶ 61,048 (2005), reh'g denied, 111 FERC ¶ 61,178 (2005), and Promotion of a More Efficient Capacity Release Market, Order No. 712-A, FERC Stats. & Regs. ¶ 31,284, at P 146 (2008), order on reh'g and clarification, Order No. 712-B, 127 FERC ¶ 671,051 (2009).

Q. Absent FERC approval, will the incremental pipeline capacity and LNG supply provide benefits to EDC customers?

A. Yes, although not necessarily to the magnitude that has been estimated by Black & Veatch in its market analysis of the proposed solutions. The EDCs prefer that electric generators are able to access the pipeline and storage assets prior to the capacity being released and made available to others as the proposed solution is meant to solve the problem of gas generators not having firm transportation capabilities with unconstrained natural gas commodity prices available to them. To the extent other shippers in the market secure the firm transportation rights ahead of the electric generators for an extended period of time, the gas generators that may have benefited may still see pipeline constraints and higher prices during extreme weather conditions reducing the benefits flowing to the wholesale electric markets. In the event other non-generation shippers outbid generators and secure the firm transportation under normal pipeline release mechanisms, EDCs may get a larger credit back against the capacity payments but at the expense of potentially higher wholesale electric energy payments. So benefits will still be realized from the ANE Project even if "priority" releases are not allowed by the respective state commissions or FERC but not likely to the same extent as with priority release to generators first. We believe an exemption or waiver by the FERC from the generic capacity release rules would enable achievement of more of the benefits that policy makers were seeking and that the

proposed solution were meant to achieve in both reliability and wholesale electric energy prices. The ANE Agreement requires that the pipeline seek authorization from FERC allowing the preferential release of capacity to generators. If such authorization is not obtained, the Company would have the right to terminate the Proposed Agreement. In the event that the Company waived its right to terminate the Proposed Agreement, the pipeline capacity can and would be released consistent with FERC's existing rules for non-discriminatory release. The EDCs are seeking approval for ~~"p~~priority" releases only to have the most direct impact possible on electric retail prices. However, with or without the ability to conduct priority releases, the ANE Project will increase the amount of gas available in the competitive marketplace. The incremental capacity creates increased liquidity and market depth for sellers to find bidders, which ultimately leads to lower retail prices. Lower gas prices have shown to be highly correlated to electricity prices in the region and therefore should lead to lower power prices.

IX. Ratemaking Issues

Q. What is the National Grid proposal for recovery of the costs associated with the Proposed Agreements, including credits to customers?

A. The ratemaking mechanism that National Grid is proposing for recovery of the Proposed Agreement and the crediting of net releases to customers is described in detail in the testimony of Ms. Ann E. Leary. From a high level, the mechanism is

designed to net costs against expected revenues so that customers are charged a net cost that is recovered from all customers through a uniform per kWh rate.

The Cost elements of the ANE Agreement includes: (1) fixed and variable transportation charges; (2) storage inventory costs and injection and withdrawal charges; and (3) administration charges, which would encompass fees paid to the Capacity Manager and consulting fees or other similar administrative and general costs incurred by the Company to effectuate the Proposed Agreement and achieve mitigation revenues. Revenues offsetting these costs would be obtained from capacity releases and sales from LNG inventory. The Company is also requesting an innovation incentive as discussed in the pre-filed direct testimony of Michael C. Calviou.

Q. Would you be more specific about the types of costs that would be recovered through the Administrative cost category?

A. National Grid anticipates that there will be a category of costs that are necessarily incurred to complete the contracting process and to carry out the activities that will be necessary to bring the contract resources to the market place, similar to the types of costs companies incur in order to provide Basic Service to default service customers. For example, National Grid will incur costs in this proceeding to present the analysis required by the PUC to support contract approval.

Q. What efforts will the Company undertake to recover contract costs regionally?

A. The Company's (affiliates, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid have submitted precedent agreements with the DPU that are substantially similar to the Proposed Agreement. The DPU is currently reviewing those agreements, with evidentiary hearings expected during the summer of 2016.[32] It is anticipated that regional states and their respective electric distribution companies will work collectively to ensure regional recovery.

X. Financial Impacts of Proposed Agreement and Proposed Incentive for Innovation

Q. Please explain how the Company evaluated the potential financial impacts of the proposed agreements and the importance of assured full cost recovery.

A. The Company retained The Brattle Group to evaluate the potential financial risk for the Company from the Proposed Agreement. The Brattle Group's analysis is presented in the pre-filed direct testimony and schedules of Dr. Michael J. Vilbert. Dr. Vilbert's testimony also sets forth how this financial risk could impact the Company's cost of capital and underscores the importance of the Company's request for assured full cost recovery of all contract-related costs for the duration of the Proposed Agreement.

[32] D.P.U. 16-05.

Q. Please describe the importance of utility innovation and the Company's request for an innovation incentive related to the Proposed Agreements.

A. Mr. Calviou explains how the present and future electric utility business environment requires electric distribution utilities to innovate with regard to technologies, business practices, customer offerings, and policies and regulation**.** Rhode Island would be well served if the PUC were to facilitate innovation that is likely to provide a public benefit, including lowering the cost of energy. Consistent with the PUC's history of providing incentives intended to foster and reward utility efforts that yield customer benefits, the Company requests an innovation incentive equal to 2.75 percent of the annual fixed contract payments under the Proposed Agreement for having contributed substantially to the development of an innovative solution to a major energy challenge facing Rhode Island and New England.

XI. Conclusion

Q. Does this conclude your pre-filed testimony in this proceeding?

A. Yes. It does.

Schedule TJB/JEA-1
Precedent & Service Agr.

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PRECEDENT AGREEMENT

This PRECEDENT AGREEMENT ("Precedent Agreement") is made and entered into this 17 day of ~~May~~ June, 2016 ("Effective Date"), by and between Algonquin Gas Transmission, LLC ("Pipeline"), a Delaware limited liability company, and The Narragansett Electric Company d/b/a National Grid ("Customer"). Pipeline and Customer are sometimes referred to individually as a "Party" and collectively as the "Parties."

WITNESSETH:

WHEREAS, Pipeline owns and operates an interstate natural gas transmission system in the Northeastern United States;

WHEREAS, Customer desires that Pipeline expand such interstate natural gas transmission system and use the resulting capacity to enhance New England's electric reliability and energy competitiveness in connection with the Access Northeast Project, the details of which were publicly announced on September 16, 2014 (the "Project");

WHEREAS, Pipeline is proposing to implement a new Rate Schedule ERS for firm transportation of natural gas that is supported by a new liquefied natural gas facility to be located in Acushnet, Massachusetts ("Acushnet Facility"), in connection with Project, and will file Rate Schedule ERS with the Federal Energy Regulatory Commission ("Commission" or "FERC") for approval;

WHEREAS, subject to the terms and conditions of this Precedent Agreement, Pipeline is proposing to construct, own and operate facilities necessary to provide firm transportation entitlements under Rate Schedule ERS in aggregate of 900,000 Dth/d for electric distribution companies, supported by storage capacity of 6,400,000 Dth, vaporization entitlements of 400,000

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Dth/d, and liquefaction entitlements of 54,000 Dth/d of natural gas, in connection with the Project;

WHEREAS, subject to the terms and conditions of this Precedent Agreement, Pipeline is willing to construct the Project and provide the firm transportation service that Customer desires;

NOW, THEREFORE, in consideration of the mutual covenants herein assumed, and intending to be legally bound, Pipeline and Customer agree as follows:

1) Pipeline Obligations. Subject to the terms and conditions of this Precedent Agreement, Pipeline shall proceed with due diligence to obtain from all governmental and regulatory authorities having competent jurisdiction over the premises, including, but not limited to, the Commission, the authorizations and/or exemptions Pipeline determines are necessary: (i) for Pipeline to construct, install, own, operate, and maintain the Project facilities, and, if applicable, abandon existing facilities, necessary to provide the firm transportation service contemplated herein, for Pipeline to implement Rate Schedule ERS and any additional conforming tariff revisions, and include such rate schedule as part of its FERC Gas Tariff and for Pipeline to implement an amendment to the capacity release provisions in its FERC Gas Tariff to establish a process for a customer to release firm capacity to electric generators on a priority basis pursuant to state-approved programs ("Capacity Release Tariff Amendment") (collectively, "Pipeline's Authorizations"); and (ii) for Pipeline to perform its obligations as contemplated in this Precedent Agreement. Pipeline reserves the right to file and prosecute any and all applications for such authorizations, any supplements or amendments thereto, and, if necessary, any request for rehearing or court review, that are consistent with this Precedent Agreement, the Service Agreement as defined in Paragraph 3(a), and the Negotiated Rate Agreement as defined in Paragraph 3(b), in a manner it deems to be in its

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best interest. Pipeline agrees to provide Customer with an opportunity to review and comment on the text of Pipeline's application for a certificate of public convenience and necessity for the Project, and Exhibits K and P to such application, to be provided to Customer at least five (5) business days in advance of the filing date and shall in good faith work with Customer to address any concerns raised by Customer with respect to such application. Pipeline agrees to promptly notify Customer in writing when each of Pipeline's Authorizations is received, obtained, rejected or denied. Pipeline shall also promptly notify Customer in writing as to whether each of Pipeline's Authorizations that has been received or obtained is acceptable to Pipeline. During the term of this Precedent Agreement, Pipeline also agrees to use reasonable efforts to support and cooperate with, and to not oppose, obstruct or otherwise interfere with, Customer in Customer's efforts to obtain Customer Authorizations as referenced below. In the event that any necessary FERC authorization or approval for the Capacity Release Tariff Amendment is not received by Pipeline by October 1, 2016, Pipeline shall have the right to terminate this Precedent Agreement. Pipeline's termination right pursuant to this Paragraph 1 expires if it is not exercised within ten (10) days after October 1, 2016. The term of the Precedent Agreement will commence on the Effective Date and continue until the Precedent Agreement is terminated pursuant to Paragraphs 9, 10 or 11 hereof.

2) Customer Obligations.

a) Subject to the terms and conditions of this Precedent Agreement, Customer shall proceed with due diligence to obtain all necessary and appropriate authorizations and approvals from governmental and regulatory authorities having jurisdiction over the premises, the Customer or the Customer's cost recovery including, but not limited to,

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such authorizations and approvals for Customer to perform its obligations as contemplated in this Precedent Agreement, the Service Agreement (defined below), and the Negotiated Rate Agreement (defined below) and to recover the costs associated therewith ("Customer Authorizations").

b) Customer reserves the right to file and prosecute applications for Customer Authorizations, and, if necessary, any court review, in a manner it deems to be in its best interest. Customer agrees to promptly notify Pipeline in writing when each of Customer Authorizations is received, obtained, rejected or denied. Customer shall also promptly notify Pipeline in writing as to whether each of Customer Authorizations that has been received or obtained is acceptable to Customer. All Customer Authorizations must be issued in a form acceptable to Customer.

c) For so long as the Customer Authorizations have not been received and accepted by Customer, Customer shall coordinate with Pipeline regarding the status of the Customer Authorizations on a monthly basis.

d) During the term of this Precedent Agreement, Customer agrees to use reasonable efforts to support and cooperate with, and to not oppose, obstruct or otherwise interfere with the efforts of Pipeline to obtain Pipeline's Authorizations, to provide the firm transportation service contemplated in this Precedent Agreement, and to perform its other obligations as contemplated by this Precedent Agreement. Nothing herein shall be construed to limit or waive Customer's rights to intervene or protest any filing by Pipeline to the extent Customer determines in good faith that such filing is not consistent with Pipeline's obligations or Customer's rights under this Precedent Agreement, the Service Agreement or the Negotiated Rate Agreement. Notwithstanding the foregoing,

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Customer agrees to intervene in the FERC proceeding established to consider the Capacity Release Tariff Amendment and to file comments with FERC in support of such filing to the extent such filing is consistent with this Precedent Agreement, the Service Agreement as defined in Paragraph 3(a), and the Negotiated Rate Agreement as defined in Paragraph 3(b). Pipeline shall provide notice to Customer of Pipeline's filing of the Capacity Release Tariff Amendment with the FERC.

3) Service Agreement.

a) To effectuate the firm transportation service contemplated herein, Customer and Pipeline agree that no later than twenty five (25) days following the date on which the Commission issues an order granting Pipeline a certificate of public convenience and necessity to construct the Project facilities or, upon Pipeline's request to Customer, within a shorter time following the issuance of such certificate as may be deemed necessary by Pipeline in its reasonable discretion to allow Pipeline to commence the construction of the Project, Pipeline and Customer will execute a firm transportation service agreement under Rate Schedule ERS in the form attached as Attachment A hereto ("Service Agreement"), which:

i) specifies an initial Maximum Daily Transportation Quantity ("MDTQ") of 64,800 Dth/d with [redacted] to be in effect on the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date, Phase 3 Service Commencement Date, Phase 4 Service Commencement Date, respectively (each as determined in accordance with Paragraph 4 of this Precedent Agreement);

ii) specifies an initial Maximum Storage Quantity ("MSQ") equal to 460,800 Dth to be effective on the Phase [redacted] Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement);

iii) specifies a primary term ("Primary Term") of twenty (20) years commencing on the Phase 1 Service Commencement Date, as defined below;

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iv) specifies the following Non-Storage Primary Point(s) of Receipt and Maximum Daily Receipt Obligation(s) ("MDRO"):

(1) Mahwah (Meter No. 00201) with an MDRO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement), [redacted] to be in effect on the Phase 2 Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement) and 36,000 Dth/d to be in effect on the Phase 3 Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement);

(2) Ramapo (Meter No. 00214) with an MDRO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted]d to be in effect on the Phase 2 Service Commencement Date and 36,000 Dth/d to be in effect on the Phase 3 Service Commencement Date;

(3) Brookfield (Meter No. 00251) with an MDRO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement Date and 26,280 Dth/d to be in effect on the Phase 3 Service Commencement Date (collectively "Non-Storage Primary Points of Receipt")

provided, however, the sum of the MDROs at all Non-Storage Primary Points of Receipt contemplated in this clause 3(a)(iv) on any day shall not exceed Customer's MDTQ in effect on such date following the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date and Phase 3 Service Commencement Date, and 36,000 Dth/d following the Phase 4 Service Commencement Date;

v) specifies a Storage Primary Point of Receipt from storage to be effective on the Phase[redacted] Service Commencement Date at Acushnet (Meter No. [TBD]) with an MDRO equal to 28,800 Dth/d;

vi) specifies the following Aggregation Areas for Primary Points of Delivery:

(1) Connecticut with a Maximum Daily Delivery Obligation ("MDDO") equal to [redacted] to be in effect on the Phase 1 Service Commencement Date[redacted] to be in effect on the Phase 2 Service Commencement Date, [redacted] to be in effect on the Phase 3 Service Commencement Date, and 27,360 Dth/d to be in effect on the Phase 4 Service Commencement Date;

(2) Massachusetts with an MDDO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement Date, [redacted] to be in effect on the

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Phase 3 Service Commencement Date, and 25,920 Dth/d to be in effect on the Phase 4 Service Commencement Date;

(3) SEMA – G System with an MDDO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement Date, [redacted] to be in effect on the Phase 3 Service Commencement Date, and 5,760 Dth/d to be in effect on the Phase 4 Service Commencement Date; and

(4) Maine with an MDDO equal to [redacted] to be in effect on the Phase 1 Service Commencement Date, [redacted] to be in effect on the Phase 2 Service Commencement Date, [redacted]th/d to be in effect on the Phase 3 Service Commencement Date, and 5,760 Dth/d to be in effect on the Phase 4 Service Commencement Date;

provided, however, the sum of the MDDOs at all Primary Point(s) of Delivery contemplated in this clause 3(a)(vi) on any day shall not exceed Customer's MDTQ in effect on such date; and

vii) specifies a Maximum Daily Injection Quantity ("MDIQ") equal to 3,888 Dth to be effective on the Phase [redacted] Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement);

viii) specifies a Maximum Daily Withdrawal Quantity ("MDWQ") equal to 28,800 Dth to be effective on the Phase [redacted] Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement);

ix) incorporates creditworthiness provisions set forth in this Precedent Agreement.

The Customer's MDTQ and MSQ shall be subject to adjustment to the extent necessary to comply with applicable state law, regulation or order (including, without limitation, Customer's Authorizations), and further by agreement of the Parties as described below. The Aggregate EDC Capacity shall be 900,000 Dth/d, with [redacted] available on the Phase 1 Service Commencement Date, an additional [redacted] [redacted] available on the Phase 2 Service Commencement Date, an additional [redacted] available on the Phase 3 Service Commencement Date, and an additional [redacted] available on the Phase 4 Service Commencement Date. On or before [redacted], Pipeline will provide notice to Customer of the status of the Aggregate EDC Capacity for which

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Pipeline has firm commitments. [redacted] Notwithstanding the foregoing, in the event that an interim storage option will be available after the Phase 1 Service Commencement Date (as defined below) but prior to the Phase 4 Service Commencement Date (as defined below), then Customer shall have the right, but not the obligation, to take Customer's

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Proportionate Share of such interim storage service on the terms set forth in this Precedent Agreement, the Service Agreement and the Negotiated Rate Agreement until the Phase 4 Service Commencement Date. If Customer exercises its right to such available interim storage service and quantities and such service and quantities will be provided for one (1) year or more, Pipeline and Customer may amend this Precedent Agreement, the Service Agreement and the Negotiated Rate Agreement (as defined below) to provide for service from such interim storage option with comparable volume and rate provisions until the Phase 4 Service Commencement Date subject to the Customer's receipt of necessary regulatory approvals. Pipeline will accept its FERC certificate of public convenience and necessity to construct the Project facilities no later than five (5) days after the execution of the Service Agreement between Pipeline and Customer.

b) Rate. Pipeline and Customer further agree that, contemporaneously with the execution of this Precedent Agreement, they will execute, in accordance with Section 46 of the General Terms and Conditions ("GT&C") of Pipeline's Tariff, a negotiated rate agreement ("Negotiated Rate Agreement"), as set forth on Attachment C hereto, consistent with the terms of this Precedent Agreement which shall become effective on the Phase 1 Service Commencement Date and shall provide for a negotiated rate applicable to service under the Service Agreement, subject to approval by the Commission. In accordance with and subject to the terms of the Negotiated Rate Agreement, Pipeline may adjust the negotiated rate to reflect any increase or decrease in the actual Project capital costs.

c) Primary Term Extension. [redacted]

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[redacted]

d) Renewal. The Primary Term or Primary Term Extension, as applicable, will automatically extend for annual periods at the same MDTQ, MSQ, MDROs, MDDOs, MDIQ and MDWQ unless terminated in accordance with this Paragraph 3(d). Either Party may terminate at the end of the Primary Term, Primary Term Extension or any of the [redacted] provided that in the event Customer elects to extend the Primary Term pursuant to Paragraph 3(c) but subsequently revokes such election, Customer may terminate at the end of the Primary Term by providing notice to Pipeline within sixty (60) days after the date that is three (3) years prior to the end of the Primary Term. The applicable rates during the term of such renewal shall be the rates set forth in the Negotiated Rate

Agreement, if applicable.

e) Right of First Refusal. Upon Pipeline's termination of the Service Agreement at the end of the Primary Term, Primary Term Extension or annual renewal terms as contemplated by Paragraph 3(d) of this Precedent Agreement, Customer shall have a Right of First Refusal pursuant to Pipeline's Tariff to be applicable to all of the Customer's MDTQ and MSQ, exercisable in accordance with the notice and other applicable provisions of the Tariff.

f) Most Favored Nation Right. Customer shall have a Most Favored Nation Right as set forth in the Negotiated Rate Agreement. All electric distribution companies that are Project customers shall have the same, or substantially similar, material terms and conditions as contained in this Precedent Agreement, the Service Agreement or the Negotiated Rate Agreement.

4) Commencement of Service.

a) Phase 1 Service Commencement Date. Upon satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the service included in Phase 1, Pipeline shall notify Customer of such fact, and that service under the Service Agreement for such Phase 1 service will commence on a date certain, which date will be the later of: (i) November 1, 2018 and (ii) the date that all of the conditions precedent set forth in Paragraph 7 of this Precedent Agreement are satisfied or waived with respect to Phase 1 ("Phase 1 Service Commencement Date").

b) Phase 2 Service Commencement Date. Upon satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the service included in Phase 2, Pipeline shall notify Customer of such fact, and that

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service under the Service Agreement for such Phase 2 service will commence on a date certain, which date will be the later of: (i) November 1, 2019 and (ii) the date that all of the conditions precedent set forth in Paragraph 7 of this Precedent Agreement are satisfied or waived with respect to Phase 2 ("Phase 2 Service Commencement Date"); provided that, in the event that the Phase 1 Service Commencement Date has occurred and Customer provides notice of termination pursuant to 9(b) based on the failure of the Phase 2 Service Commencement Date to occur by the date specified in Paragraph 9(b), Pipeline may, within five (5) business days, provide notice to Customer of the satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the Phase 2 service, including service that does not include any storage rights, and that service under the Service Agreement for such portion of Phase 2 service will commence on a date certain, which date will be the first day of the month that is no earlier than fifteen (15) days after the date of such notice ("Phase 2 Partial Service Commencement Date").

c) Phase 3 Service Commencement Date. Upon satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the service included in Phase 3, Pipeline shall notify Customer of such fact, and that service under the Service Agreement for such Phase 3 service will commence on a date certain, which date will be the later of: (i) November 1, 2020 and (ii) the date that all of the conditions precedent set forth in Paragraph 7 of this Precedent Agreement are satisfied or waived with respect to Phase 3 ("Phase 3 Service Commencement Date"); provided that, in the event that the Phase 1 Service Commencement Date and Phase 2 Service Commencement Date have occurred and Customer provides notice of termination

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pursuant to 9(b) based on the failure of the Phase 3 Service Commencement Date to occur by the date specified in Paragraph 9(b), Pipeline may, within five (5) business days, provide notice to Customer of the satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the Phase 3 service, including service that does not include any storage rights, and that service under the Service Agreement for such portion of Phase 3 service will commence on a date certain, which date will be the first day of the month that is no earlier than fifteen (15) days after the date of such notice ("Phase 3 Partial Service Commencement Date").

d) Phase 4 Service Commencement Date. Upon satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the service included in Phase 4, Pipeline shall notify Customer of such fact, and that service under the Service Agreement for such Phase 4 service will commence on a date certain, which date will be the later of: (i) May 1, 2021 and (ii) the date that all of the conditions precedent set forth in Paragraph 7 of this Precedent Agreement are satisfied or waived with respect to Phase 4 ("Phase 4 Service Commencement Date"); provided that, in the event that the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date and Phase 3 Service Commencement Date have occurred and Customer provides notice of termination pursuant to 9(b) based on the failure of the Phase 4 Service Commencement Date to occur by the date specified in Paragraph 9(b), Pipeline may, within five (5) business days, provide notice to Customer of the satisfaction or waiver of all the conditions precedent set forth in Paragraph 7 of this Precedent Agreement with respect to a portion of the Phase 4 service, including service

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that does not include any storage rights, and that service under the Service Agreement for such portion of Phase 4 service will commence on a date certain, which date will be the first day of the month that is no earlier than fifteen (15) days after the date of such notice ("Phase 4 Partial Service Commencement Date," and together with the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date, Phase 2 Partial Service Commencement Date, Phase 3 Service Commencement Date, Phase 3 Partial Service Commencement Date, and Phase 4 Service Commencement Date, each a "Service Commencement Date" and, collectively, "Service Commencement Dates").

e) Under no circumstances shall the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date, Phase 3 Service Commencement Date, and Phase 4 Service Commencement Date be later than [redacted] respectively, unless otherwise agreed in writing by both Parties. On and after the date on which Pipeline has notified Customer that service under the Service Agreement will commence for each phase, Pipeline shall provide firm service under Rate Schedule ERS for Customer for such phase pursuant to the terms of the Service Agreement and Customer will pay Pipeline for all applicable charges required by the Service Agreement and the Negotiated Rate Agreement for such phase. The Parties shall amend the Service Agreement to the extent required to implement Paragraph 4 of this Precedent Agreement.

5) Design and Permitting of Project Facilities. Pipeline will undertake with due diligence the design of the Project facilities and any other preparatory actions necessary for Pipeline to complete and file its application(s) related to the Project with the Commission or other governmental authority as appropriate. Prior to satisfaction of the conditions precedent set

forth in Paragraph 7 of this Precedent Agreement, Pipeline shall have the right, but not the obligation (subject to Paragraph 6 of this Precedent Agreement), to proceed with the necessary design of facilities, acquisition of materials, supplies, properties, rights-of-way and any other necessary preparations to implement the firm transportation service under the Service Agreement as contemplated in this Precedent Agreement.

6) Construction of Project. Upon satisfaction of the conditions precedent set forth in Paragraphs 7(a)(i) through 7(a)(iv), inclusive, 7(a)(vi) and 7(b)(i) through 7(b)(iii), inclusive, of this Precedent Agreement, or waiver of the same by Pipeline or Customer, as applicable, and the Parties' execution of the Service Agreement, Pipeline shall proceed (subject to the continuing commitments of substantially all customers executing precedent agreements and service agreements for service utilizing the firm transportation capacity to be made available by the Project) with due diligence to construct the authorized Project facilities in phases and to implement the firm transportation service contemplated in this Precedent Agreement for Phase 1 on November 1, 2018, Phase 2 on November 1, 2019, Phase 3 on November 1, 2020, and Phase 4 on May 1, 2021. If, notwithstanding Pipeline's due diligence, Pipeline is unable to commence the firm transportation service for Customer as contemplated herein for Phase 1 on November 1, 2018, Phase 2 on November 1, 2019, Phase 3 on November 1, 2020, or Phase 4 on May 1, 2021, Pipeline will continue to proceed with due diligence to complete arrangements for such firm transportation service, and commence the firm transportation service for Customer for any such phase at the earliest practicable date thereafter. Pipeline will neither be liable nor will this Precedent Agreement or the Service Agreement be subject to cancellation if Pipeline is unable to complete construction of such authorized Project facilities and commence the firm transportation service contemplated herein for Phase 1 by

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November 1, 2018, Phase 2 by November 1, 2019, or Phase 3 by November 1, 2020, or Phase 4 by May 1, 2021, subject to Customer's rights in Paragraph 9(b) of this Precedent Agreement.

7) Conditions Precedent. Commencement of service under the Service Agreement and Pipeline's and Customer's rights and obligations under the Service Agreement are expressly made subject to satisfaction of the following conditions precedent in this Paragraph 7 (only Pipeline shall have the right to waive the conditions precedent set forth in Paragraph 7(a) and only Customer shall have the right to waive the conditions precedent set forth in Paragraph 7(b)):

a) Pipeline's Conditions Precedent.

i) Pipeline's receipt and acceptance by June 1, 2021, of (i) all necessary certificates and authorizations from the Commission to construct, install, own, operate, and maintain the Project facilities, and, if applicable, abandon existing facilities, all as described in Pipeline's certificate application as it may be amended from time to time, to provide the firm transportation service contemplated herein and in the Service Agreement, and to perform its other obligations contemplated herein, and (ii) an order from the Commission approving or accepting the Capacity Release Tariff Amendment;

ii) Pipeline's receipt of approval, on or before the date the Pipeline files its certificate application with the Commission, from its Board of Directors, or similar governing body, to expend the capital necessary to construct the Project facilities and/or to execute the Service Agreement;

iii) Pipeline's receipt, on or before [redacted], of all necessary governmental authorizations, approvals, and permits required to implement Rate Schedule ERS and

include such rate schedule as part of its FERC Gas Tariff, and to construct the Project facilities necessary to provide the firm transportation service contemplated herein and in the Service Agreement other than those specified in Paragraph 7(a)(i);

iv) Pipeline's procurement, on or before [redacted], of all rights-of-way, easements or permits (in form and substance acceptable to Pipeline) necessary for the construction and operation of the Project facilities;

v) Pipeline's completion of construction of the Project facilities and all other facilities required to render firm transportation service for Customer pursuant to the Service Agreement for the applicable phase and Pipeline being ready and able to place such facilities into gas service at the full MDTQ and/or MSQ for such phase on or before [redacted] for Phase 1, [redacted] for Phase 2, [redacted] for Phase 3, and [redacted] for Phase 4; and

vi) Customer's receipt and acceptance by October 1, 2016, of Customer Authorizations identified in accordance with Paragraph 2 of this Precedent Agreement, which Customer Authorizations are acceptable to Pipeline.

b) Customer's Conditions Precedent.

i) Customer's receipt of approval, on or before July 1, 2016, from its Board of Directors, or similar governing body, to participate in the Project;

ii) Customer's receipt and acceptance by October 1, 2016, of Customer Authorizations in a final and non-appealable form acceptable to Customer; and

iii) Pipeline's receipt by December 1, 2020, of (i) a certificate from the Commission authorizing Pipeline to construct, install, own, operate, and maintain the Project facilities, and, if applicable, abandon existing facilities, all as described in Pipeline's

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certificate application as it may be amended from time to time, to provide the firm transportation service contemplated herein and in the Service Agreement, and to perform its other obligations contemplated herein; and (ii) an order from the Commission approving or accepting the Capacity Release Tariff Amendment.

c) With respect to each condition precedent set forth in Paragraph 7(a) of this Precedent Agreement, Pipeline shall use commercially reasonable efforts to provide notice to Customer within five (5) days of the date that such condition precedent has been satisfied or waived. With respect to the conditions precedent set forth in Paragraphs 7(b)(i) and (ii) of this Precedent Agreement, Customer shall use commercially reasonable efforts to provide notice to Pipeline within five (5) days of the date that such condition precedent has been satisfied or waived. The failure of either Pipeline or Customer to notify the other as contemplated by this Paragraph 7(c) shall not be considered a breach of this Precedent Agreement nor shall it be considered cause for either Party to terminate this Precedent Agreement. [redacted]

d) Unless otherwise provided for herein, Pipeline's Authorizations contemplated in Paragraph 1 of this Precedent Agreement and otherwise associated with the firm transportation service contemplated by this Precedent Agreement must be issued in form and substance reasonably satisfactory to both Parties hereto; provided that this Paragraph 7(d) does not give rise to a termination right for Pipeline independent of Pipeline's

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termination right pursuant to Paragraph 9(a). Pipeline shall provide written notice to Customer not later than ten (10) days after issuance of any of Pipeline's Authorizations, and shall offer to meet with Customer promptly upon the issuance of any such authorization(s) not issued or granted in form and substance as requested to discuss concerns or issues related thereto. For purposes of this Precedent Agreement, Pipeline's Authorizations shall be deemed satisfactory to Customer if such Authorizations are consistent with the terms of this Precedent Agreement, the Service Agreement, the Negotiated Rate Agreement, and the Customer's Authorizations, and do not impose conditions or obligations that substantially and adversely affect Customer. To the extent Customer determines in Customer's sole and reasonable judgment that the Pipeline's Authorizations do not satisfy the requirements of the immediately preceding sentence, Customer shall notify Pipeline in writing not later than ten (10) days after receipt of Pipeline's notice of such Authorizations, and shall detail the basis of such determination. Designated representatives for the Parties shall meet promptly and negotiate in good faith to reach mutual agreement on a reasonable modification or an agreeable alternative to address such substantial and adverse effect(s), and each Party agrees to discuss in good faith any positions advanced by the other Party in accordance with the foregoing. All other governmental authorizations, approvals, permits and/or exemptions that Pipeline must obtain must be issued in form and substance reasonably acceptable to Pipeline. All governmental approvals that Pipeline is required by this Precedent Agreement to obtain must be duly granted by the Commission or other governmental agency or authority having jurisdiction, and must be final and no longer subject to rehearing or appeal; provided, however, Pipeline may waive the requirement that such authorization(s) and

approval(s) be final and no longer subject to rehearing or appeal. Pipeline shall provide quarterly updates to Customer regarding Pipeline's progress in obtaining Pipeline's Authorizations.

8. Limitation of Liability. NOTWITHSTANDING THE FOREGOING, THE PARTIES HERETO AGREE THAT NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR ANY PUNITIVE, SPECIAL, EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES (INCLUDING, WITHOUT LIMITATION, LOSS OF PROFITS OR BUSINESS INTERRUPTIONS) ARISING OUT OF OR IN ANY MANNER RELATED TO THIS PRECEDENT AGREEMENT, AND WITHOUT REGARD TO THE CAUSE OR CAUSES THEREOF OR THE SOLE, CONCURRENT OR CONTRIBUTORY NEGLIGENCE (WHETHER ACTIVE OR PASSIVE), STRICT LIABILITY (INCLUDING, WITHOUT LIMITATION, STRICT STATUTORY LIABILITY AND STRICT LIABILITY IN TORT) OR OTHER FAULT OF EITHER PARTY. THE IMMEDIATELY PRECEDING SENTENCE SPECIFICALLY PROTECTS EACH PARTY AGAINST SUCH PUNITIVE, EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES EVEN IF RELATED TO THE NEGLIGENCE, GROSS NEGLIGENCE, WILLFUL MISCONDUCT, STRICT LIABILITY OR OTHER FAULT OR RESPONSIBILITY OF SUCH PARTY; AND ALL RIGHTS TO RECOVER SUCH DAMAGES OR PROFITS ARE HEREBY WAIVED AND RELEASED.

9. Termination of Precedent Agreement for Failure of Conditions Precedent.

a) If the conditions precedent set forth in Paragraph 7(a) of this Precedent Agreement have not been fully satisfied or waived by Pipeline by the applicable dates specified therein or

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the Service Commencement Dates have not occurred by [redacted], and this Precedent Agreement has not been terminated pursuant to Paragraphs 9(b), 10 or 11 hereof, then Pipeline may thereafter terminate this Precedent Agreement (and the Service Agreement, if executed), with respect to all phases of service for which the Service Commencement Date has not occurred, by providing thirty (30) days' prior written notice of its intention to terminate to Customer; provided, however, if the conditions precedent are satisfied, or waived by Pipeline within such thirty (30) day notice period, then termination of such agreements will not be effective. Pipeline's termination right pursuant to this Paragraph 9(a) expires if it is not exercised within ten (10) days after the deadline giving rise to such termination right. A termination pursuant to this Paragraph 9(a) shall not terminate any phase or partial phase of service for which the Service Commencement Date has occurred. In the event of such termination, Customer shall have no financial or other obligation to Pipeline.

b) If the conditions precedent set forth in Paragraph 7(b) of this Precedent Agreement have not been fully satisfied or waived by Customer by the applicable dates specified therein or if Pipeline has not completed construction of the applicable phase of the Project facilities required to render firm transportation service for Customer and the Phase 1 Service Commencement Date, Phase 2 Service Commencement Date, Phase 3 Service Commencement Date, or Phase 4 Service Commencement Date has not occurred by [redacted] respectively, and this Precedent Agreement has not been terminated pursuant to Paragraphs 9(a), 10 or 11 hereof, then Customer may thereafter terminate this Precedent Agreement (and the Service Agreement, if executed), with respect to all phases of service

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for which the Service Commencement Date has not occurred, by providing thirty (30) days' prior written notice of its intention to terminate to Pipeline; provided, however, if the conditions precedent are satisfied, or waived by Customer within such thirty (30) day notice period (as applicable), then termination of such agreements will not be effective; and, provided further, if Pipeline provides notice of partial Phase 2 service, partial Phase 3 service, or partial Phase 4 service pursuant to Paragraph 4(b), 4(c) or 4(d), respectively, then such termination will not be effective as to such partial phase. Customer's termination right pursuant to this Paragraph 9(b) expires if it is not exercised within ten (10) days after the deadline giving rise to such termination right. A termination pursuant to this Paragraph 9(b) shall not terminate any phase or partial phase of service for which the Service Commencement Date has occurred. In the event of such termination, Customer shall have no financial or other obligation to Pipeline. [redacted]

10. Additional Termination Rights. In addition to the provisions of Paragraph 9 hereof, Pipeline may terminate this Precedent Agreement (and the Service Agreement, if executed) by providing written notice of termination to Customer if, by the date specified in Paragraph 7(a)(i), Pipeline, in its sole and reasonable discretion, determines for any reasons that the Project contemplated herein is no longer economically viable. In the event of such termination, Customer shall have no financial or other obligation to Pipeline.

11. Termination upon Service Commencement Date. If this Precedent Agreement is not

terminated pursuant to Paragraphs 9 or 10 hereof, then this Precedent Agreement will terminate with respect to each phase on the Service Commencement Date for such phase, and thereafter Pipeline's and Customer's rights and obligations related to the transportation service contemplated herein shall be determined pursuant to the terms and conditions of the Service Agreement, the Negotiated Rate Agreement and Pipeline's FERC Gas Tariff, as effective from time to time. Notwithstanding any termination of this Precedent Agreement pursuant to Paragraphs 9, 10 or 11 hereof, or otherwise, to the extent that a provision of this Precedent Agreement contemplates that one or both Parties may have further rights and/or obligations hereunder following such termination, the provision shall survive such termination as necessary to give full effect to such rights and/or obligations.

12. Creditworthiness. On or within five (5) business days after the Effective Date of this Precedent Agreement, Customer shall satisfy the creditworthiness requirements as set forth in this Paragraph 12.

    a. Creditworthiness Standard. Customer shall at all times during the effectiveness of this Precedent Agreement and the Primary Term of the Service Agreement be "Creditworthy". For purposes herein, Customer will be considered Creditworthy if Customer: (i) has and continues to maintain a long-term senior, unsecured debt rating, or in the absence of a long-term senior, unsecured debt rating, a local long-term issuer rating or an issuer rating, as applicable, from (a) Moody's Investors Service, Inc. or its successor entity of similar business intent ("Moody's") of Baa3 with stable outlook or higher, and (b) Standard & Poor's or its successor entity of similar business intent ("S&P") of BBB- with stable outlook or higher, or if a

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customer is not rated by one of the foregoing agencies, then a long-term senior, unsecured debt rating, a local long-term issuer rating or an issuer rating, as applicable, from Fitch Ratings Inc. or its successor entity of similar business intent ("Fitch") of BBB- with stable outlook or higher may be substituted, and (ii) has, as of the Effective Date of this Precedent Agreement or, in the event of an assignment or permanent release of this Precedent Agreement, as of the effective date of such assignment or permanent release, sufficient open line of credit with Pipeline and its affiliates. For the avoidance of doubt, the Parties acknowledge that Pipeline has determined that Customer has a sufficient open line of credit with Pipeline and its affiliates and that such determination as it relates to the Project will be effective through the end of the Primary Term of the Service Agreement. [redacted] The extent Pipeline enters into a precedent agreement with any other Project customer which contains a less stringent "Creditworthy" standard than set forth in this subpart (a), Pipeline will offer Customer the option, at Customer's election, to substitute such other standard for the standard set forth in this subpart (a). If at any time and from time to time during the effectiveness of this Precedent Agreement and/or the Service Agreement, Pipeline determines that Customer is not Creditworthy, or if Pipeline initially finds Customer to be Creditworthy but subsequently determines that Customer is no longer Creditworthy, then Customer will provide, or cause to be provided, either a guaranty ("Guaranty") or a letter of credit ("Letter of Credit")

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in accordance with Paragraphs 12(b) and/or 12(c) as applicable.

b. Guaranty. If Customer fails to meet the requirements of Paragraph 12(a) and Customer elects to provide a Guaranty to satisfy its obligations, such Guaranty shall be issued by Customer's parent company or affiliate, or by a third party (a "Guarantor"), provided such Guarantor is Creditworthy and Guarantor remains Creditworthy for so long as it guarantees Customer's payment obligations. The Guaranty shall: (i) guarantee all payment obligations of Customer under this Precedent Agreement and the Service Agreement, (ii) remain in effect until Customer regains the Creditworthy status, and (iii) be in a form acceptable to Pipeline, which for purposes herein shall mean in form and content substantially similar to Attachment E. If the original Guarantor is, at any time, no longer Creditworthy, Pipeline may require Customer to provide, or cause to be provided, one of the following: (i) a replacement guaranty from a Creditworthy guarantor, or (ii) a letter of credit as described in Paragraph 12(c) to supplement the existing Guaranty, or (iii) a letter of credit as described in Paragraph 12(c) which replaces the existing Guaranty.

c. Letter of Credit. If at any time and from time to time during the effectiveness of this Precedent Agreement and/or the Service Agreement, Customer fails to meet the requirements of Paragraph 12(a) and Customer elects to provide a Letter of Credit to satisfy its obligations, or if Customer has provided a Guaranty but Guarantor at any time fails to meet the requirements of Paragraph 12(b) above, Customer shall provide, or cause to be provided, at its sole cost, a standby irrevocable Letter of Credit from a Qualified Financial Institution. For purposes

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herein, a "Qualified Financial Institution" shall mean a major U.S. commercial bank, or the U.S. branch offices of a foreign bank, which is not Customer or Customer's Guarantor (or a subsidiary or affiliate of Customer or Customer's Guarantor) and which has assets of at least $10 billion dollars and a credit rating of at least "A-" by S&P and at least "A3" by Moody's. The Letter of Credit shall: (i) remain in effect until the earlier of (A) the end of the Primary Term of the Service Agreement, or (B) until Customer is Creditworthy, (ii) be in a form acceptable to Pipeline, which for purposes herein shall mean in form and content substantially similar to Attachment D hereto, and (iii) be in an amount set forth in the next sentence of this Paragraph 12(c) [redacted] If Customer (or Customer's Guarantor, if applicable) is no longer Creditworthy due solely to the lack of a stable outlook for any of the applicable ratings stated in Paragraph 12(a)(i), then the Letter of Credit will be in an amount equal to [redacted]. If Customer (or Customer's Guarantor, if applicable) has a long-term senior, unsecured debt rating, or in the absence of a long-term senior, unsecured debt rating, a local long-term issuer rating or an issuer rating, as applicable, from (a) Moody's of Ba1 or lower, and (b) S&P of BB+ or lower, or if Customer is not rated by one of the foregoing agencies and Customer has substituted a Fitch rating in its place, then a Fitch rating of BB+ or lower, then the Letter of Credit will be in an amount equal to [redacted] To the extent the Letter of Credit is no longer required pursuant to the terms of the Precedent Agreement, Pipeline will return

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Customer's credit assurance no later than the fifth (5^{th}) business day following Customer's written request. Pipeline may require Customer at its cost to substitute a Letter of Credit with another Qualified Financial Institution if the Letter of Credit provided is, at any time, from a financial institution which is no longer a Qualified Financial Institution.

d. Tariff Credit Provisions Apply. The collateral requirements set forth in this Paragraph 12, while in effect, shall be in lieu of the collateral requirements under Section 3.2(d)(i) of the GT&C of Pipeline's FERC Gas Tariff, which would otherwise be applicable to Customer with respect to service on and after the Service Commencement Date under the Service Agreement; provided that all other credit requirements under the GT&C of Pipeline's FERC Gas Tariff will be applicable to Customer with respect to service on and after the Service Commencement Date under the Service Agreement.

e. Continuing Obligation. The credit support provided to Pipeline in this Paragraph 12 shall continue in effect until full and irrevocable payment of all outstanding balances and charges incurred under the Precedent Agreement and/or during the Primary Term of the Service Agreement.

f. Pipeline Notification. Notwithstanding anything in this Paragraph 12 to the contrary, if at any time and from time to time during the effectiveness of this Precedent Agreement and/or the Service Agreement Pipeline determines that Customer is not satisfying the requirements in this Paragraph 12, Pipeline shall notify Customer in writing, and Customer shall satisfy, or cause to be satisfied, such requirement(s) as soon as reasonably practicable, but in no event later than

the close of the fifth (5th) business day following receipt of such notice from Pipeline. If Customer elects to provide a Letter of Credit pursuant to subparagraph 12(c), Pipeline will accept from Customer a cash deposit on or before such fifth (5th) business day until such time as Customer causes such Letter of Credit to be issued, provided that such Letter of Credit shall be issued no later than the close of the fifteenth (15th) business day.

g. Failure to Comply. The failure of Customer to timely satisfy or maintain the requirements set forth in this Paragraph 12 shall in no way relieve Customer or Pipeline of their respective obligations under this Precedent Agreement and/or the Service Agreement, nor shall it affect Pipeline's right to seek damages or performance under this Precedent Agreement and/or the Service Agreement related to Customer's failure to timely satisfy or maintain such requirements. Further, in the event of such failure, Pipeline shall have the right, but not the obligation, to suspend or terminate performance under this Precedent Agreement, or to terminate this Precedent Agreement, upon ten (10) days prior written notice by Pipeline following the fifth (5th) business day notice period set forth in Paragraph 12(f).

h. Term of Credit Provisions and Survival. This Paragraph 12 shall survive the termination of this Precedent Agreement and shall remain in effect until all payment obligations under this Precedent Agreement, and all payment obligations through the end of the Primary Term of the Service Agreement, have been satisfied in full. If the Service Agreement remains in effect after the end of the Primary Term, then Customer shall be responsible for complying with the

applicable credit provisions under Pipeline's FERC Gas Tariff in effect at such time.

i. Replacement Customer Creditworthiness. In the event Customer assigns this Precedent Agreement and/or the Service Agreement in accordance with the applicable assignment provision(s), or in the event Customer permanently releases all or a portion of Customer's capacity under the Service Agreement in accordance with Section 14 of the GT&C of Pipeline's FERC Gas Tariff, the assignee and/or the permanent replacement customer, as applicable, shall be required to satisfy the requirements of this Paragraph 12 until all payment obligations under this Precedent Agreement and the Service Agreement have been satisfied in full.

13. Amendments. This Precedent Agreement may not be modified or amended unless the Parties execute written agreements to that effect.

14. Prior Agreements. This Precedent Agreement and its attachments, when executed, supersede all prior agreements and understandings, whether oral or written, with respect to the Project.

15. Successors; Assignments. Any company which succeeds by purchase, merger, or consolidation of title to the properties, substantially as an entirety, of Pipeline or Customer, will be entitled to the rights and will be subject to the obligations of its predecessor in title under this Precedent Agreement. Otherwise, neither Customer nor Pipeline may assign any of its rights or obligations under this Precedent Agreement without the prior written consent of the other Party hereto, provided that such consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, Pipeline

and Customer shall each have the right, without obtaining the other Party's consent, to pledge or assign its rights under this Precedent Agreement and/or the Service Agreement as collateral security for indebtedness incurred by such Party or its affiliate.

16. No Third-Party Rights. Except as expressly provided for in this Precedent Agreement, nothing herein expressed or implied is intended or shall be construed to confer upon or give to any person not a Party hereto any rights, remedies or obligations under or by reason of this Precedent Agreement.

17. Joint Efforts: No Presumptions. Each and every provision of this Precedent Agreement shall be considered as prepared through the joint efforts of the Parties and shall not be construed against either Party as a result of the preparation or drafting thereof. It is expressly agreed that no consideration shall be given or presumption made on the basis of who drafted this Precedent Agreement or any specific provision hereof.

18. Recitals and Representations. The recitals and representations appearing first above are hereby incorporated in and made a part of this Precedent Agreement.

19. Choice of Law. This Precedent Agreement shall be governed by, construed, interpreted, and performed in accordance with the laws of the Commonwealth of Massachusetts, without recourse to any laws governing the conflict of laws.

20. Notices. Except as herein otherwise provided, any notice, request, demand, statement, or bill provided for in this Precedent Agreement, or any notice which either Party desires to give to the other, must be in writing and will be sent by two of the following means: electronic mail, facsimile transmission, hand delivery or courier to the other Party at the addresses set forth below:

Pipeline: Attn: General Manager, Business Development

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5400 Westheimer Court
Houston, Texas 77056
Phone: (713) 627-5400
Fax: (713) 627-
Email: gncrisp@spectraenergy.com

Customer: Attn: John Allocca
Director of Gas Contracting and Compliance
Massachusetts Electric Co. d/b/a National Grid
100 East Old Country Road
Hicksville, New York 11801
Phone: (516) 545-3108
Fax: (516) 545-3130
Email: john.allocca@nationalgrid.com

or at such other address as either Party designates by written notice. Notices given hereunder by electronic mail or facsimile will be deemed to have been effectively given the day indicated on the confirmation accompanying the electronic submission or facsimile. Notices given hereunder by reputable overnight courier will be deemed to have been effectively given on the next business day after sending.

21. Defined Terms. When used in this Precedent Agreement, and unless otherwise defined herein, capitalized terms shall have the meanings set forth in Pipeline's FERC Gas Tariff on file with the Commission, as amended from time to time.

22. Waivers. The waiver by either Party of a breach or violation of any provision of this Precedent Agreement will not operate as or be construed to be a waiver of any subsequent breach or violation hereof.

23. Counterparts. This Precedent Agreement may be executed in any number of counterparts, each of which will be an original, but such counterparts together will constitute one and the same instrument.

24. Headings. The headings contained in this Precedent Agreement are for reference

purposes only and shall not affect the meaning or interpretation of this Precedent Agreement.

25. Representations and Warranties. Each Party represents and warrants to each other that as of the Effective Date or, if such representation and warranty is the subject of a condition precedent in Paragraph 7, as of the date of the satisfaction of such condition precedent:

(i) Such Party is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Precedent Agreement;

(ii) The execution, delivery and performance of this Precedent Agreement by such Party have been and remain duly authorized by all necessary corporate action and do not and will not contravene Party's constitutional documents or any contractual restriction binding on Party or its assets;

(iii) This Precedent Agreement has been duly executed and delivered by such Party. This Precedent Agreement constitutes the legal, valid, binding and enforceable obligation of such Party, except as such enforceability may be limited by bankruptcy, insolvency, reorganization and other similar laws and by general principles of equity;

(iv) No governmental authorization, approval, order, license, permit, franchise or consent, and no registration, declaration or filing with any governmental authority is required on the part of such Party in connection with execution and delivery of this Precedent Agreement, although it is subject to the necessary governmental approvals specified herein for its effectuation.

(v) There is no pending or, to the best of such Party's knowledge, threatened action or proceeding affecting such Party before any court, governmental authority or arbitrator that could reasonably be expected to materially and adversely affect the financial condition or operations of such Party or the ability of such Party to permit its obligations hereunder, or that purports to affect the legality, validity or enforceability of this Precedent Agreement or would otherwise hinder or prevent performance hereunder.

26. Confidentiality and Disclosures.

(a) The substance and terms of this Precedent Agreement are confidential. Either Party may disclose the substance and terms of this Precedent Agreement to its or its affiliates' directors, officers, employees, representatives, agents, consultants, attorneys or auditors

("Representatives") who have a need to know the substance and terms of this Precedent Agreement. Pipeline and Customer agree not to disclose or communicate, and will cause their respective Representatives not to disclose or communicate, the substance or terms of this Precedent Agreement to any other person, entity, firm, or corporation without the prior written consent of the other Party, provided that either Party may disclose the substance or terms of this Precedent Agreement as required by law, order, rule or regulation of any duly constituted governmental body or official authority having jurisdiction, subject to the condition that the disclosing Party first give the other Party five (5) business days' notice of same or as much notice as possible under the circumstances, so that a protective order or other protective arrangements may be sought. Notwithstanding the foregoing, the Parties acknowledge that (A) Pipeline may, in its sole discretion, exercised reasonably, (i) file a copy of this Precedent Agreement with the FERC under seal in connection with the FERC certificate application, (ii) place on public file with the FERC a description of the terms of any negotiated rate prior to the commencement of firm transportation service under the Service Agreement, and (iii) use the terms and conditions of this Precedent Agreement (excluding any information proprietary to Customer) in Pipeline's preparation of the pro forma precedent agreement for other shippers under the Project, and (B) Customer, in its sole discretion, may provide Project information, including a copy of this Precedent Agreement, to the Rhode Island Public Utilities Commission; provided Pipeline or Customer will request confidential treatment for any such filing or written disclosure. Such filings will not constitute a breach of this confidentiality provision and will not require compliance with the foregoing five (5) day notice provision. If this Precedent Agreement is terminated pursuant to Paragraphs 9, 10 or 11 above or otherwise by mutual agreement of the Parties, then this

Paragraph 26 will survive for a period of two (2) years from and after the effective date of such termination.

(b) The following will not constitute confidential information for purposes of this Precedent Agreement: (i) information which is or becomes generally available to the public other than as a result of a disclosure by the Party receiving the confidential information or its Representatives; (ii) information which was already known to the Party receiving the confidential information on a non-confidential basis prior to being furnished such information by the other Party; (iii) information which becomes available to the Party receiving the confidential information on a non-confidential basis from a source other than the Party providing such confidential information or its Representative if such source was not known by the Party receiving such information to be subject to any prohibition against transmitting the information to such Party; or (iv) information which was or is independently developed by Party receiving the confidential information or its Representatives without reference to, or consideration of, confidential information.

(c) Notwithstanding Paragraph 26(a) above, and subject to the Parties' prior approval of any public announcements or disclosures related to Customer's participation in the Project, it is understood and agreed by the Parties that the intent of the marketing effort for the Project will be to disclose to other potential Project customers that Pipeline and Customer have executed this Precedent Agreement for Customer to be an anchor shipper for the Project. Customer agrees that Pipeline shall be permitted to make public announcements and disclosures related to the existence of this Precedent Agreement, and the MDTQ, target Service Commencement Date and Primary Term set forth herein, without Pipeline obtaining any further approvals from Customer. Likewise, Pipeline agrees that Customer shall be

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permitted to discuss the Project with its state regulators and other stakeholders, including the existence of this Precedent Agreement, and the MDTQ, MSQ, target Service Commencement Date and Primary Term set forth herein, without obtaining any further approvals from Pipeline.

[signature page follows]

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IN WITNESS WHEREOF, the Parties hereto have caused this Precedent Agreement to be duly executed by their duly authorized officers as of the day and year first above written.

Algonquin Gas Transmission, LLC

By: William T. Yardley
Title: President

The Narragansett Electric Company d/b/a National Grid

By: John V. Vaughn
Title: Authorized Signatory

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Attachment A
Form of Rate Schedule ERS Service Agreement

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FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

[This Form of Service Agreement may be revised to reflect non-substantive changes that are included in the Form of Service Agreement applicable to Rate Schedule ERS as of the date of execution pursuant to Paragraph 3 of the Precedent Agreement and will be revised to reflect the specific terms of the Precedent Agreement, including, without limitation, the contractual ROFR.]

Date: _____, Contract No. _____

SERVICE AGREEMENT

This AGREEMENT is entered into by and between Algonquin Gas Transmission, LLC, ("Algonquin") and _____ ("Customer").

[or, when applicable, "This Agreement entered into this __ day of _____, ____, by and between Algonquin Gas Transmission, LLC ("Algonquin") and _____, as "Administrator" on behalf of the Principals set forth in Multiple Shipper Option Agreement ("MSOA") Contract No. _____, hereinafter individually and collectively referred to as "Customer," which Principals meet the requirements set forth in such MSOA which is incorporated herein by reference."]

WHEREAS, [this and an additional clause(s) may be included to describe the historical or factual context of the Agreement, to describe or identify a precedent agreement, and any other agreements if applicable, between Algonquin and Customer related to the Agreement, and/or to describe or define the facilities necessary to provide service under the Agreement, and will not include binding consideration.]

[***In the event that the capacity was awarded as Interim Capacity pursuant to Section 2.6 of the General Terms and Conditions of the Algonquin Tariff, the following language will be included as a Whereas clause in Customer's Agreement:*** "The service provided to Customer under this Agreement will utilize capacity that was acquired by Customer as Interim Capacity pursuant to the provisions of Section 2.6 of the General Terms and Conditions of the Algonquin Tariff."]

NOW THEREFORE, in consideration of the premises and of the mutual covenants herein contained, the parties do agree as follows:

1. Algonquin shall deliver and Customer shall take and pay for service pursuant to the terms of this Agreement and subject to Algonquin's Rate Schedule ERS and the General Terms and Conditions of Algonquin's Tariff, which are incorporated herein by reference and made a part hereof.

   [***In the event that a precedent agreement for a new or an expansion project contains credit provisions applicable to Customer's capacity related to such project, the following language shall be included in Customer's Service Agreement.*** "The credit requirements applicable to this Agreement are set forth in that certain Precedent Agreement dated _____ between Algonquin and Customer related to this Agreement."]

2. The Maximum Daily Transportation Quantity (MDTQ) for transportation service under this Agreement and any right to increase or decrease the MDTQ during the term of this Agreement are listed on Exhibit C attached hereto. The Maximum Daily Injection Quantity (MDIQ), Maximum Storage Quantity (MSQ), and Maximum Daily Withdrawal Quantity (MDWQ) for the storage service under this Agreement, and any right to increase or decrease the MDIQ, MSQ or MDWQ during the term of this Agreement are listed on Exhibit D attached hereto. The Primary Point(s) of

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Receipt, Maximum Daily Receipt Obligation (MDRO), Base Flow Path, if applicable, and Base Flow Path Quantity, if applicable, are listed on Exhibit A attached hereto. The Primary Point(s) of Delivery, Maximum Daily Delivery Obligation (MDDO), and Enhanced Maximum Hourly Transportation Quantity (Enhanced MHTQ), if applicable, are listed on Exhibit B attached hereto. Exhibit(s) A, B, C and D are incorporated herein by reference and made a part hereof.

3. This Agreement shall be effective on _____ [this blank may include a date certain, a date either earlier or later than a specified date certain based on the completion of construction of facilities necessary to provide service under the Agreement, a date set forth in or established by a relevant order from the Federal Energy Regulatory Commission or a commencement date as defined in a precedent agreement between Customer and Algonquin] and shall continue for a term ending on and including _____ [or, when applicable, "shall continue for a term of ____ years"] ("Primary Term") and shall continue to be effective from _____ to _____ thereafter [***In the event that the capacity was awarded as Interim Capacity pursuant to Section 2.6 of the General Terms and Conditions of the Algonquin Tariff, the following phrase will be included in Customer's Agreement:*** ",but in no event beyond _____,"] unless and until terminated by Algonquin or Customer upon prior written notice of at least _____[not less than 1 year for agreements with a primary term of more than 1 year; for service agreements with both a primary term and notice period of exactly one (1) year, the notice must be submitted within ten (10) Business Days of the beginning of the primary term of the service agreement, and at least one (1) year for subsequent notices for such service agreement; and otherwise mutually agreeable]. [In the event that Algonquin and Customer agree to a fixed term, the evergreen and notice of termination language shall be omitted from Customer's Agreement.] This Agreement may be terminated at any time by Algonquin in the event Customer fails to pay part or all of the amount of any bill for service hereunder and such failure continues for thirty days after payment is due; provided Algonquin gives ten days prior written notice to Customer of such termination and provided further such termination shall not be effective if, prior to the date of termination, Customer either pays such outstanding bill or furnishes a good and sufficient surety bond or other form of security reasonably acceptable to Algonquin guaranteeing payment to Algonquin of such outstanding bill; provided that Algonquin shall not be entitled to terminate service pending the resolution of a disputed bill if Customer complies with the billing dispute procedure currently on file in Algonquin's Tariff. Any portions of this Agreement necessary to correct or cash-out imbalances under this Agreement as required by the General Terms and Conditions of Algonquin's Tariff shall survive the other parts of this Agreement until such time as such balancing has been accomplished.

If this Agreement qualifies as a "ROFR Agreement" as defined in the General Terms and Conditions of Algonquin's Tariff, the provision of a termination notice by either Customer or Algonquin, pursuant to the preceding paragraph, a notice of partial reduction in Maximum Daily Transportation Quantity, Maximum Daily Injection Quantity, Maximum Storage Quantity, and Maximum Daily Withdrawal Quantity, as applicable, pursuant to Exhibit C or D, as applicable, or the expiration of this Agreement of its own terms triggers Customer's right of first refusal under Section 9 of the General Terms and Conditions of Algonquin's Tariff.

[***In the event that the capacity was awarded as Interim Capacity pursuant to Section 2.6 of the General Terms and Conditions of the Algonquin Tariff, the previous paragraph will be replaced with the following language:*** "This Agreement does not qualify as a ROFR Agreement, as such term is defined in Section 1 of the General Terms and Conditions of the Algonquin Tariff."]

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4. Maximum rates, charges, and fees shall be applicable to service pursuant to this Agreement except during the specified term of a discounted rate or a Negotiated Rate to which Customer and Algonquin have agreed. Provisions governing such discounted rate shall be as specified in the Discount Confirmation to this Agreement. Provisions governing such Negotiated Rate and term shall be as specified on an appropriate Statement of Negotiated Rates filed, with the consent of Customer, as part of Algonquin's Tariff. It is further agreed that Algonquin may seek authorization from the Commission and/or other appropriate body at any time and from time to time to change any rates, charges or other provisions in the applicable Rate Schedule and General Terms and Conditions of Algonquin's Tariff, and Algonquin shall have the right to place such changes in effect in accordance with the Natural Gas Act. Nothing contained herein shall be construed to deny Customer any rights it may have under the Natural Gas Act, including the right to participate fully in rate or other proceedings by intervention or otherwise to contest increased rates in whole or in part.

5. Unless otherwise required in the Tariff, all notices shall be in writing and shall be considered duly delivered when mailed to the applicable address below or transmitted via facsimile. Customer or Algonquin may change the addresses or other information below by written notice to the other without the necessity of amending this Agreement:

Algonquin:

Customer:

6. The interpretation and performance of this Agreement shall be in accordance with the laws of the Commonwealth of Massachusetts, excluding conflicts of law principles that would require the application of the laws of a different jurisdiction.

7. This Agreement supersedes and cancels, as of the effective date of this Agreement, the contract(s) between the parties hereto as described below, if applicable:

[None or an appropriate description]

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IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be signed by their respective Officers and/or Representatives thereunto duly authorized to be effective as of the date stated above.

CUSTOMER: _____

By:_____

Title:_____

ALGONQUIN GAS TRANSMISSION, LLC

By:_____

Title:_____

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FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

Exhibit A

Point(s) of Receipt

Dated: _____

To the service agreement under Rate Schedule ERS dated _____ between Algonquin Gas Transmission, LLC (Algonquin) and _____ (Customer) concerning Point(s) of Receipt.

Exhibit A Effective Date: _____

Primary Point of Receipt	Maximum Daily Receipt Obligation	Maximum Receipt Pressure
[Base Flow Path]		[Base Flow Path Quantity]

[Notice: Additional information may be included where the Base Flow Path cannot be clearly identified from the Maximum Daily Receipt Obligation(s) [MDRO(s)] and/or aggregate MDRO(s), the Base Flow Path set forth on Exhibit A of Customer's ERS service agreement, and the Maximum Daily Delivery Obligation(s) (MDDO(s)) and/or aggregate MDDO(s) set forth on Exhibit B of Customer's ERS Service Agreement.]

[Notice: The sum of the Maximum Daily Receipt Obligations (MDROs) in total across any two or more Primary Points of Receipt may also be further limited by a specified aggregate MDRO ("AMDRO"), as applicable.]

Signed for Identification

Algonquin: _____

Customer: _____

Supersedes Exhibit A Dated _____

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FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

Exhibit B

Point(s) of Delivery

Dated: _____

To the service agreement under Rate Schedule ERS dated _____ between Algonquin Gas Transmission, LLC (Algonquin) and _____ (Customer) concerning Point(s) of Delivery.

Exhibit B Effective Date: _____

Primary Point of Delivery	Maximum Daily Delivery Obligation	Minimum Delivery Pressure	[Enhanced MHTQ]

[NOTICE: The sum of the Maximum Daily Delivery Obligations (MDDOs) in total across any two or more Primary Points of Delivery may also be further limited by a specified aggregate MDDO ("AMDDO"), as applicable.

[NOTICE: In the event that Customer and Algonquin have reached an agreement for an Enhanced MHTQ at a Point of Delivery under Customer's ERS Service Agreement, the column heading Enhanced MHTQ will be included in Exhibit B to Customer's ERS Service Agreement.]

Signed for Identification

Algonquin: _____

Customer: _____

Supersedes Exhibit B Dated _____

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FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

Exhibit C

Transportation Quantities

Dated: _____

To the service agreement under Rate Schedule ERS dated _____ between Algonquin Gas Transmission, LLC (Algonquin) and _____ (Customer) concerning transportation quantities.

Exhibit C Effective Date: _____

MAXIMUM DAILY TRANSPORTATION QUANTITY (MDTQ):

Dth	Period

[*In the event that Algonquin and Customer agree upon MDTQs that are not the same for each period specified above, the highest MDTQ will be identified with a footnote using an asterisk and the following accompanying text:* "MDTQ to be utilized in applying the monthly Reservation Charge."]

PARTIAL QUANTITY REDUCTION RIGHTS: Customer elects to partially reduce Customer's Maximum Daily Transportation Quantity by _____ dth as of _____, or any subsequent anniversary date, upon providing _____ [Notice period to be not less than the notice period required to terminate the entire contract] year(s) prior written notice to Algonquin.

Algonquin and Customer agree that, if this Agreement qualifies as a "ROFR Agreement", (i) the foregoing contractual right to partially reduce Customer's Maximum Daily Transportation Quantity is in addition to and not in lieu of any ROFR right to reduce Customer's Maximum Daily Transportation Quantity on a volumetric basis upon termination or expiration of this Agreement and (ii) only the partial reduction pursuant to the foregoing contractual right to partially reduce Customer's Maximum Daily Transportation Quantity is subject to the ROFR procedures specified in the General Terms and Conditions of Algonquin's Tariff and Customer may retain the balance of the Maximum Daily Transportation Quantity without being subject to the ROFR procedures.

Signed for Identification

Algonquin: _____

Customer: _____

Supersedes Exhibit C Dated _____

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FORM OF SERVICE AGREEMENT
(APPLICABLE TO RATE SCHEDULE ERS)

Exhibit D

Storage Quantities

Dated: _____

To the service agreement under Rate Schedule ERS dated _____ between Algonquin Gas Transmission, LLC (Algonquin) and _____ (Customer) concerning storage quantities.

Exhibit D Effective Date: _____

MAXIMUM STORAGE QUANTITY (MSQ): _____ Dth

MAXIMUM DAILY INJECTION QUANTITY (MDIQ): _____ Dth
Dth Period

MAXIMUM DAILY WITHDRAWAL QUANTITY (MDWQ): _____ Dth
Dth Period

PARTIAL QUANTITY REDUCTION RIGHTS: Customer elects to partially reduce Customer's MDIQ by _____ dth, MSQ by _____ dth and MDWQ by _____ dth, maintaining the existing MDIQ, MSQ and MDWQ relationship, as of _____, or any subsequent anniversary date, upon providing _____ [Notice period to be not less than the notice period required to terminate the entire contract] year(s) prior written notice to Algonquin.

Algonquin and Customer agree that, if this Agreement qualifies as a "ROFR Agreement", (i) the foregoing contractual right to partially reduce Customer's Maximum Storage Quantity is in addition to and not in lieu of any ROFR right to reduce Customer's Maximum Storage Quantity on a volumetric basis upon termination or expiration of this Agreement and (ii) only the partial reduction pursuant to the foregoing contractual right to partially reduce Customer's Maximum Storage Quantity is subject to the ROFR procedures specified in the General Terms and Conditions of Algonquin's Tariff and Customer may retain the balance of the Maximum Storage Quantity without being subject to the ROFR procedures.

Signed for Identification

Algonquin: _____

Customer: _____

Supersedes Exhibit D Dated _____

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Attachment B
Retail Market Share

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Retail Market Share

ELECTRIC DISTRIBUTION COMPANY	CUSTOMER'S EDC SHARE (PERCENT)
Connecticut Light & Power Co. d/b/a Eversource Energy	21.7%
United Illuminating Company	5.1%
NSTAR Electric Co. d/b/a Eversource Energy	19.6%
Western Massachusetts Elec. Co. d/b/a Eversource Energy	3.4%
Massachusetts Electric Co. d/b/a National Grid	20.0%
Nantucket Electric Co. d/b/a National Grid	0.1%
Unitil Energy Services, Inc. - Massachusetts	0.4%
Central Maine Power Co.	7.9%
Emera Maine	1.4%
Public Service Co. of New Hampshire d/b/a Eversource Energy	7.4%
Unitil Energy Services, Inc. - New Hampshire	1.2%
Liberty Utilities - New Hampshire	0.9%
Narragansett Electric Co. d/b/a National Grid	7.2%
Green Mountain Power Company	3.7%
Total	100%

*2014 ISONE Annual Twelve Month Average of Monthly Peak Network Loads

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Attachment C
Negotiated Rate Agreement

REDACTED

ALGONQUIN GAS TRANSMISSION, LLC
5400 Westheimer Court
Houston, TX 77056-5310
713.627.5400 main

Mailing Address:
P.O. Box 1642
Houston, TX 77251-1642

Spectra Energy Partners

June
~~May~~ 17 2016

John Allocca
Director of Gas Contracting and Compliance
The Narragansett Electric Company d/b/a National Grid
100 East Old Country Road
Hicksville, New York 11801

Re: Rate Schedule ERS Service Agreement (Contract No. _____) – Negotiated Rate

Dear Mr. Allocca:

By this transmittal letter, Algonquin Gas Transmission, LLC ("Algonquin") and The Narragansett Electric Company d/b/a National Grid ("Narragansett") are implementing a negotiated rate applicable to service under the above-referenced Rate Schedule ERS Service Agreement.

Algonquin and Narragansett hereby agree that the provisions on the attached *Pro Forma* Statement of Negotiated Rates reflect the terms of their agreement, including the effectiveness of the negotiated rate. After execution of this letter by both Algonquin and Narragansett, Algonquin shall file a Statement of Negotiated Rates with the Federal Energy Regulatory Commission ("Commission") containing rate-related provisions identical to those provisions on the attached *Pro Forma* Statement of Negotiated Rates in accordance with Section 46 of the General Terms and Conditions of the Algonquin tariff.

If the foregoing accurately sets forth your understanding of the matter covered herein, please so indicate by having a duly authorized representative sign in the space provided below and returning an original signed copy to the undersigned.

Sincerely,

William T. Yardley
President

ACCEPTED AND AGREED TO
THIS 17 DAY OF ~~MAY~~ JUNE, 2016

The Narragansett Electric Company d/b/a National Grid

Name: John V. Vaughn
Title: Authorized Signatory

REDACTED

STATEMENT OF NEGOTIATED RATES 1/2/3/4/5/6/7/8/

Customer Name: The Narragansett Electric Company d/b/a National Grid ("Customer")

Service Agreement: [INSERT CONTRACT NUMBER]

Term of Negotiated Rate: The term of this negotiated rate commences on the Phase 1 Service Commencement Date (as defined in the Precedent Agreement between Pipeline and Customer) of Contract No. [INSERT CONTRACT NUMBER] and continues for the Primary Term (as such term is defined in the Precedent Agreement and Contract No. [INSERT CONTRACT NUMBER]) and any evergreen term thereof. 6/ In the event that Customer exercises its option to extend the Primary Term for either [redacted] negotiated reservation rate as reflected in item (iii) under Extension Reservation Rate below, the term of this Negotiated Rate shall extend at such new negotiated rate for such extended term and any evergreen term thereof.

Rate Schedule: ERS [Access Northeast Project]

MDTQ: 7/
[redacted] on the Phase 1 Service Commencement Date
[redacted]/d on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
64,800 Dth/d on the Phase 4 Service Commencement Date

MSQ: 460,800 Dth on the Phase [redacted] Service Commencement Date 7/

Reservation Rate: Customer shall pay a negotiated reservation rate of [redacted], per month of Customer's MDTQ under Contract No. [INSERT CONTRACT NUMBER] during the Primary Term and any evergreen term of such Primary Term. 3/5/8/

Extension Reservation Rate:

(A) In the event that Customer exercises its option to extend the Primary Term for either [redacted], the rate during any such extended term and any evergreen term of such extended term, shall be chosen by Customer at the time Customer exercises its option to extend from one of the following: [redacted]

REDACTED

[redacted]

(B) [redacted]

(C) [redacted]

(D) [redacted]

(E) [redacted]

REDACTED

[redacted]

Commodity Charge: Customer shall pay the applicable maximum recourse commodity and usage rates, as reflected on the currently effective Statement of Rates for Pipeline's Rate Schedule ERS for the Project; provided, however, that such rates shall not include any allocation of fixed costs. 5/

Other Charges: 5/

Non-Storage Primary Receipt Point: 7/

Mahwah (Meter No. 00201)
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
36,000 Dth/d on the Phase 3 Service Commencement Date

Ramapo (Meter No. 00214)
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
36,000 Dth/d on the Phase 3 Service Commencement Date

Brookfield (Meter No. 00251)
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
26,280 Dth/d on the Phase 3 Service Commencement Date

Storage Primary Receipt Point(s): 7/

Acushnet (Meter No. [TBD])
28,800 Dth/d on the Phase [redacted] Service Commencement Date

Primary Delivery Points: 7/

Connecticut
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
27,360 Dth/d on the Phase 4 Service Commencement Date

Massachusetts
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
25,920 Dth/d on the Phase 4 Service Commencement Date

REDACTED

SEMA – G System
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
5,760 Dth/d on the Phase 4 Service Commencement Date

Maine
[redacted] on the Phase 1 Service Commencement Date
[redacted] on the Phase 2 Service Commencement Date
[redacted] on the Phase 3 Service Commencement Date
5,760 Dth/d on the Phase 4 Service Commencement Date

Recourse Rate(s): The Recourse Rate(s) applicable to this service is the applicable maximum rate(s) stated on Pipeline's Statement of Rates for Rate Schedule ERS [Access Northeast Project] at the applicable time.

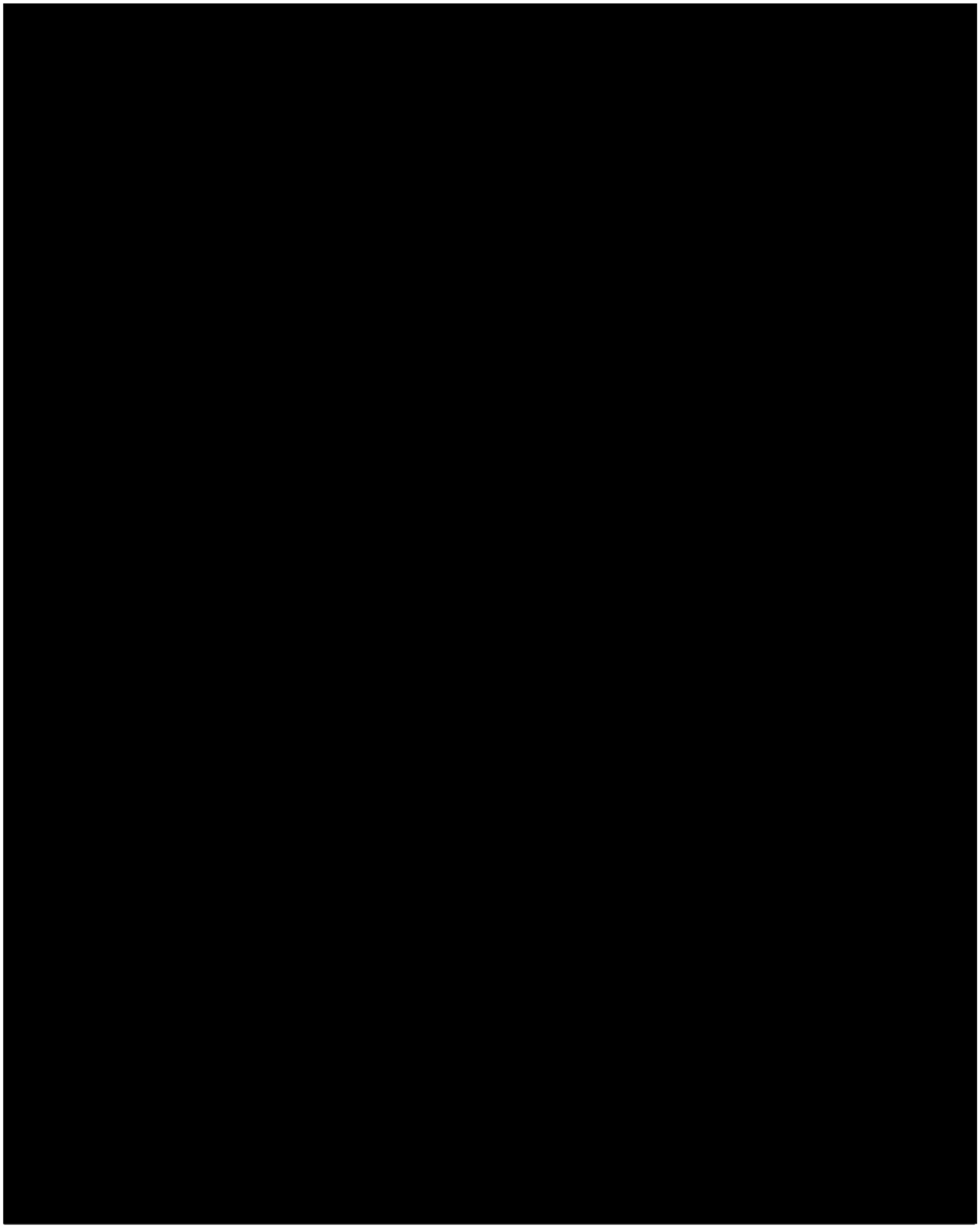
FOOTNOTES:

1/ This negotiated rate agreement is part of a non-conforming Service Agreement.

2/ This negotiated rate shall apply only to transportation service under Contract No. [INSERT CONTRACT NUMBER], up to Customer's specified MDTQ, using the Primary Receipt Point and Primary Delivery Point designated herein, and any secondary receipt and delivery points available under Rate Schedule ERS; provided if Customer changes its primary points listed above (or the MDROs or MDDOs associated with such points), pursuant to the provisions of the Pipeline's FERC Gas Tariff, Pipeline shall have the option to terminate this negotiated rate by providing Customer with written notice of Pipeline's intent to terminate the negotiated rate and, in such case, this negotiated rate shall terminate and Pipeline's maximum recourse rate for Rate Schedule ERS for the Project shall apply for the remaining term of the Service Agreement, unless and until otherwise agreed in writing between Customer and Pipeline.

3/ [redacted]

REDACTED



REDACTED

4/ Pipeline and Customer agree that Contract No. [INSERT CONTRACT NUMBER] is a ROFR Agreement.

5/ Customer shall pay (i) the applicable Fuel Reimbursement Quantity ("FRQ") under Pipeline's Rate Schedule ERS for the Project, which shall include fuel use loss related to liquefaction and compression for the storage facilities and (ii) the applicable Annual Charge Adjustment and all other charges and surcharges applicable to Rate Schedule ERS for the Project, including electric power costs and other variable operating costs for the storage facilities. Customer shall also pay any future surcharge or additional usage charge pursuant to any FERC-approved cost recovery mechanism of general applicability implemented in a generic proceeding or in a Pipeline specific proceeding, or any other recovery mechanism for the recovery of direct or indirect costs not reflected in Pipeline's FERC approved Rate Schedule ERS rates for the Project at the time of execution of this negotiated rate, including but not limited to such costs related to pipeline safety or environmental compliance costs associated with Pipeline's operation.

REDACTED

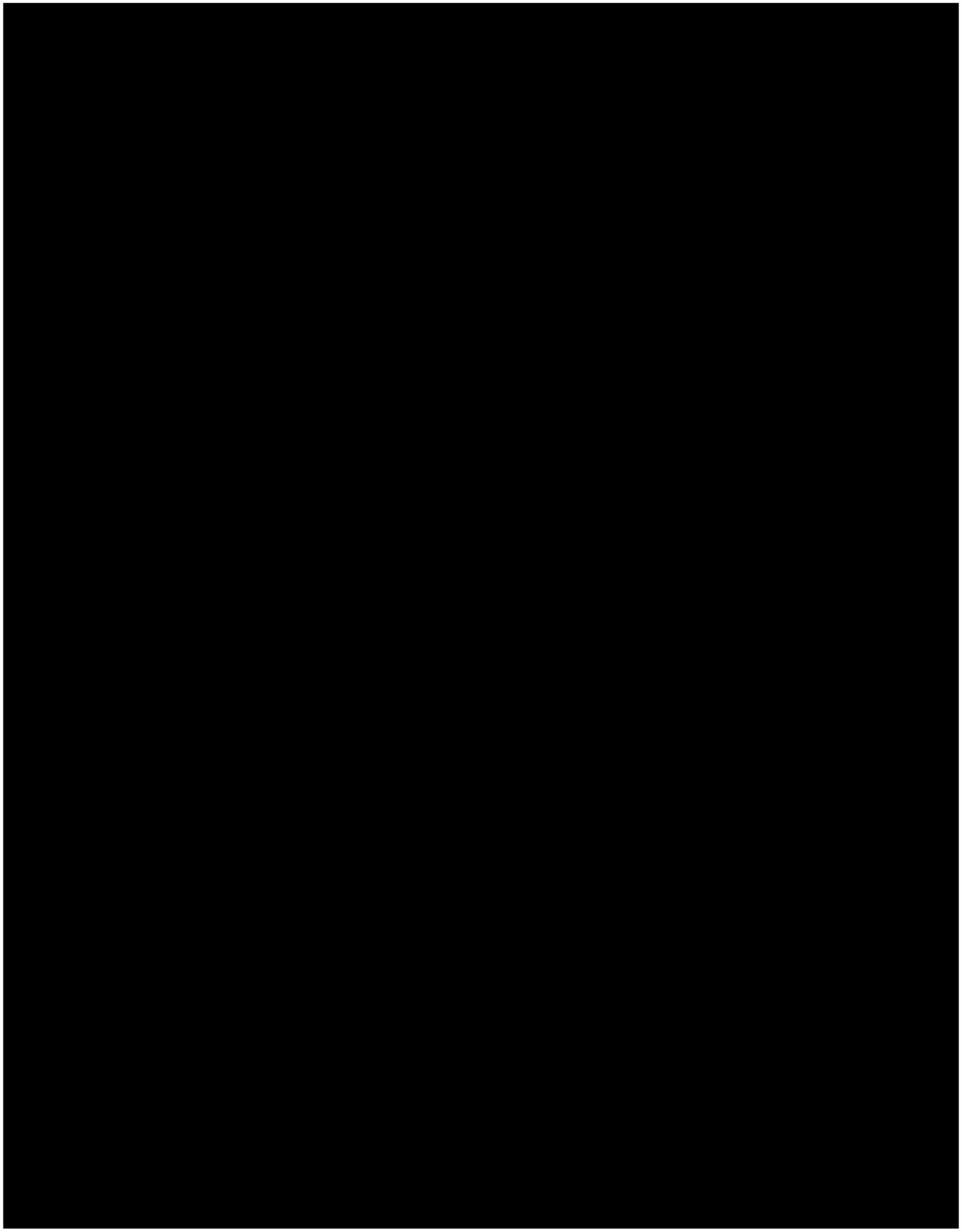
6/ If the term of Contract No. [INSERT CONTRACT NUMBER] renews for one or more twelve (12) month evergreen period(s) at the Negotiated Reservation Rate, then the term of this negotiated rate shall be extended for such evergreen period(s).

7/ The MDTQs, MSQ, MDROs, MDDOS, MDIQ, and MDWQ may be revised in accordance with Paragraph 3(a) of the Precedent Agreement.

8/ **Most Favored Nations**

[redacted]

REDACTED



REDACTED

(e) Waiver

Nothing in this footnote 8 constitutes a waiver of either party's right to seek regulatory and/or judicial relief if a party acts in a manner that is inconsistent with its obligations as set forth in this footnote.

REDACTED

Attachment D
Form of Letter of Credit

REDACTED

EXECUTION COPY

ATTACHMENT D

IRREVOCABLE STANDBY LETTER OF CREDIT

Letter of Credit No:_____

Date:_____, 20__

Date of Expiry: _____, 20__

Beneficiary:
[Spectra entity name]
5400 Westheimer Court
Houston, TX 77056

Account Party:
(Complete Legal Name)
(Address)
(City, State, Zip)

Attn: Credit Director

[Name of Bank] ("Issuing Bank") hereby establishes this Irrevocable and Transferable Standby Letter of Credit No. _____ in favor of [Spectra entity name] ("Beneficiary") for the account of [Account Party Name] ("Account Party") in connection with that certain Precedent Agreement between Account Party and Beneficiary, dated [ ], 2016 (the "Precedent Agreement"), and the related firm transportation service agreement between Account Party and Beneficiary (the "Service Agreement"), for the aggregate amount of up to (*dollar amount*) available to Beneficiary by presenting sight draft(s) to Issuing Bank when accompanied by a signed and dated statement by an authorized representative of Beneficiary certifying one or more of the following, as applicable:

1. "The amount drawn herein is to satisfy obligations of Account Party between Beneficiary and Account Party. Wherefore, the undersigned Beneficiary does hereby demand payment of $_____. Beneficiary further certifies that supporting documents when required were presented to Account Party and that Account Party has not satisfied its obligations." And / or

2. "This Letter of Credit will expire in less than thirty (30) days and Beneficiary has not received an extension of said Letter of Credit or other acceptable replacement collateral from Account Party. Wherefore, the undersigned Beneficiary does hereby demand payment of $_____. Upon timely receipt of an amendment extending this Letter of Credit, this drawing is to be considered automatically rescinded." And / or

REDACTED

3. "Issuing Bank 's lowest long-term senior unsecured debt rating no longer meets or exceeds "A-" by Standard & Poor's Rating Group and "A3" by Moody's Investor Services, Inc., and Account Party has not caused a replacement Letter of Credit from an alternate financial institution acceptable to Beneficiary to be issued to Beneficiary. Wherefore, the undersigned Beneficiary does hereby demand payment of $_____."

SPECIAL TERMS AND CONDITIONS

1. Partial and multiple drawings are allowed hereunder. The amount that may be drawn by Beneficiary under this Letter of Credit shall be automatically reduced by the amount of any payments made through Issuing Bank referencing this Letter of Credit.

2. This Letter of Credit shall automatically extend without amendment for periods of one year each from the present or any future expiry date unless Issuing Bank notifies Beneficiary in writing at least sixty (60) days prior to such present or future expiry date, as applicable, that Issuing Bank elects not to further extend this Letter of Credit.

3. This Letter of Credit is transferable without charge any number of times, but only in the amount of the full unutilized balance hereof and not in part and with the approval of Account Party which consent shall not be unreasonably withheld, conditioned or delayed.

4. The term "Beneficiary" includes any successor by operation of law of the named beneficiary to this Letter of Credit, including, without limitation, any liquidator, any rehabilitator, receiver or conservator.

5. Presentations for drawing may be delivered in person, by mail, by express delivery, or by facsimile.

6. All Bank charges are for the account of Account Party.

7. Article 36 under UCP 600 is modified as follows: If the Letter of Credit expires while the place for presentation is closed due to events described in said Article, the expiry date of this Letter of Credit shall be automatically extended without amendment to a date thirty (30) calendar days after the place for presentation reopens for business.

Issuing Bank hereby agrees with Beneficiary that documents presented for drawing in compliance with the terms of this Letter of Credit will be duly honored upon presentation at Issuing Bank's counters if presented on or before the expiry date.

Unless otherwise expressly stated herein, this Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits ("UCP"), 2007 Revision, International Chamber of Commerce Publication No. 600. Matters not covered by the UCP shall be governed and construed in accordance with the laws of the state of New York.

ISSUING BANK SIGNATURE

REDACTED

Attachment E
Form of Guaranty

REDACTED

EXECUTION COPY

Attachment E

GUARANTY

This Guaranty ("Guaranty"), dated as of _____, is made by _____, a [state and corporate structure] ("Guarantor"), in favor of _____ a [state & corporate structure] ("Beneficiary").

WHEREAS, from time to time, _____, a _____ [state and corporate structure] ("Counterparty"), and Beneficiary have entered into that certain precedent agreement dated _____ ("Precedent Agreement"), as may be amended from time to time and that certain service agreement dated _____ ("Service Agreement"), as may be amended from time to time (both Precedent Agreement and Service Agreement are collectively referred as the "Agreement");

WHEREAS, Counterparty is a wholly-owned subsidiary of Guarantor; and Guarantor will directly or indirectly benefit from the Agreement to be entered into between Counterparty and Beneficiary; and

WHEREAS, as an inducement to Beneficiary to enter into the Agreement, Guarantor has agreed to provide this Guaranty; and

WHEREAS, Guarantor has agreed to execute and deliver this Guaranty with respect to Counterparty's payment obligations under the Agreement:

NOW THEREFORE, in consideration of the premises, Guarantor hereby agrees as follows:

1. **Guaranty.** Guarantor hereby absolutely, irrevocably and unconditionally guarantees the timely payment when due of Counterparty's payment obligations arising under any Agreement, as such Agreement may be amended or modified from time to time, together with any interest thereon and fees and costs of collection (including attorney's fees and court costs) in connection therewith ("Obligation"). In the event Counterparty defaults in the payment of any of the Obligation, within ten (10) days after receiving written notice from Beneficiary, Guarantor shall make such payment or otherwise cause same to be paid. This Guaranty may be enforced by Beneficiary at any time without the necessity of first resorting to or exhausting any other security or collateral. All amounts payable by Guarantor hereunder shall be in freely transferable funds.

2. **Effectiveness.** This Guaranty is effective as of the date set forth above and is a continuing guaranty which shall remain in full force and effect throughout the term of the Agreement, including any extensions or renewals thereof, until Guarantor has completely fulfilled the Obligation. If at any time during the effectiveness of this Guaranty, Guarantor no longer qualifies as Creditworthy as defined in Paragraph XX of the Precedent Agreement, Guarantor shall, or shall cause Counterparty to, immediately provide the collateral specified in Paragraph XX(X) of the Precedent Agreement.

3. **Waivers.** (a) Guarantor waives any right to require as a condition to its obligations hereunder any of the following should Beneficiary seek to enforce the obligations of Guarantor:

(i) presentment, demand for payment, notice of dishonor or non-payment, protest, notice of protest, or any similar type of notice;

(ii) any suit be brought against, or any other action be brought against, or any notice of default or other similar notice be given to, or any demand be made upon Counterparty or any other person or entity;

(iii) notice of acceptance of this Guaranty, of the creation or existence of the Obligation, and/or any action by Beneficiary in reliance hereon or connection herewith;

(iv) notice of entering into any Agreement between Counterparty and Beneficiary, and/or any amendments, supplements or modifications thereto, or any waiver of consent under any Agreement, including waiver of the payment and performance of the Obligation thereunder; and/or

REDACTED

(v) notice of any increase, reduction or rearrangement of Counterparty's Obligation under any Agreement, or any extension of time for payment of any amounts due Beneficiary under any Agreement.

(b) Guarantor also waives the right to require, substantively or procedurally, that a judgment has been previously rendered against Counterparty or any other person or entity, or that Counterparty or any other person or entity be joined in any action against Guarantor.

4. **Assignment.** Guarantor shall not assign its duties hereunder without the prior written consent of Beneficiary. Beneficiary shall be entitled to assign its rights hereunder in its sole discretion upon prior written notice to Guarantor. Any assignment without such prior written consent or notice, as applicable, shall be null and void and of no force or effect.

5. **Notice.** All demands, notices or other communications to be given by any party to another must be in writing and shall be deemed to have been given when delivered personally or otherwise actually received or on the third (3rd) day after being deposited in the United States mail if registered or certified, postage prepaid, or one (1) day after delivery to a nationally recognized overnight courier service, fee prepaid, return receipt requested, and addressed as follows:

Guarantor's Name & Address	Beneficiary's Name & Address
_____	_____
_____	5400 Westheimer Court
_____	Houston, TX 77056
_____	Attn: Credit Director
_____	Phone: 713-627-5446
	Fax: 713-989-1717

or such other addresses as they may change from time to time by giving prior written notice to the other party.

6. **Applicable Law.** THIS GUARANTY SHALL IN ALL RESPECTS BE GOVERNED BY, ENFORCED UNDER AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK.

7. **Effect of Certain Events.** Guarantor agrees that its liability hereunder will not be released, reduced, impaired or affected by the occurrence of any one or more of the following events:

(i) the insolvency, bankruptcy, reorganization, or disability of Counterparty;
(ii) the renewal, consolidation, extension, modification or amendment from time to time of the Agreement;
(iii) the failure, delay, waiver, or refusal by Beneficiary to exercise any right or remedy held by Beneficiary with respect to the Agreement;
(iv) the sale, encumbrance, transfer or other modification of the ownership of Counterparty or the change in the financial condition or management of Counterparty; or
(v) the settlement or compromise of any Obligation.

8. **Representations and Warranties**. Guarantor hereby represents and warrants the following:

(i) Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty;
(ii) the execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene Guarantor's constitutional documents or any contractual restriction binding on Guarantor or its assets; and
(iii) this Guaranty constitutes the legal, valid and binding obligation of Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy,

REDACTED

insolvency, reorganization and other similar laws and to general principles of equity.

9. **Subrogation**. Until all amounts which may be or become payable under the Agreement have been irrevocably and indefeasibly paid in full, Guarantor shall not by virtue of this Guaranty be subrogated to any rights of Counterparty or claim in competition with Beneficiary against Counterparty in connection with any matter relating to or arising from the Obligation or this Guaranty. If any amount shall be paid to Guarantor on account of such subrogation rights at any time before all of the Obligation has been irrevocably paid in full, such amounts shall be held in trust for the benefit of Beneficiary and shall promptly be paid to Beneficiary to be applied to the Obligation.

10. **Amendment**. No term or provision of this Guaranty shall be amended, modified, altered, waived, supplemented or terminated unless first agreed to by Guarantor and Beneficiary and then set forth in a written amendment to this Guaranty.

11. **Counterparts**. This Guaranty may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute one document.

12. **Entire Agreement**. This Guaranty embodies the entire agreement and understanding between Guarantor and Beneficiary regarding payment of the Obligation under the Agreement and supersedes all prior agreements and understandings relating to the subject matter hereof.

IN WITNESS WHEREOF, Guarantor has executed this Guaranty effective as of the date first herein written.

GUARANTOR' S NAME

By:_____

Name:_____

Title:_____

REDACTED

EXECUTION COPY

Attachment F
Pro Forma Schedule

Deadline Description	Agreement Section	Agreement Provision	Calendar Deadline[1]
[redacted]			

REDACTED

[1] Assumes Phase 1 Service Commencement Date of November 1, 2018. Date to be updated based on actual Service Commencement Date.

Schedule TJB/JEA-2
Regional Coordination

NEW ENGLAND GOVERNORS' COMMITMENT TO REGIONAL COOPERATION ON ENERGY INFRASTRUCTURE ISSUES

Securing the future of the New England economy and environment requires strategic investments in our region's energy resources and infrastructure. These investments will provide affordable, clean, and reliable energy to power our homes and businesses; make our region more competitive by reducing energy costs; attract more investment to the region; and protect our quality of life and environment.

As the region's electric and natural gas systems have become increasingly interdependent, ensuring that we are efficiently using existing resources and securing additional clean energy supplies will be critical to New England's economic future. To ensure a reliable, affordable and diverse energy system, we need investments in additional energy efficiency, renewable generation, natural gas pipelines, and electric transmission. These investments will also serve to balance intermittent generation, reduce peak demand, and displace some of the least efficient and most polluting fossil fuel generation, enabling the states to meet clean energy and greenhouse gas reduction goals while improving the economic competitiveness of our region.

New England ratepayers can benefit if the states collaborate to advance our common goals. The Governors therefore commit to continue to work together, in coordination with ISO-New England and through the New England States Committee on Electricity (NESCOE), to advance a regional energy infrastructure initiative that diversifies our energy supply portfolio while ensuring that the benefits and costs of transmission and pipeline investments are shared appropriately among the New England States. At the same time, we must respect individual state perspectives, particularly those of host states, as well as the natural resources, environment, and economy of the States, and ensure that the citizens and other stakeholders of our region, including NEPOOL, are involved in the process. The Governors are committed to achieving consensus as we move forward, consistent with laws and policies across the region.

The New England States believe that investments in local renewable generation, combined heat and power, and renewable and competitively-priced heating for buildings will support local markets and result in additional cost savings, new jobs and economic opportunities, and environmental gains. The New England States further believe that these investments must be advanced in a coordinated approach in order to maximize ratepayer savings and system integrity. We will continue to advocate at ISO-New England, NEPOOL, and elsewhere for greater integration and utilization of renewable generation; development of new natural gas pipeline infrastructure; maximizing the use of existing transmission infrastructure; investment, where appropriate, in new transmission infrastructure; and continuation of the inclusion of energy efficiency – and the addition of distributed generation – in load forecasting and transmission planning.

continued…

New England Governors' Commitment to Regional Cooperation on Energy Infrastructure Issues

We have directed our appropriate staff to work together with NESCOE to ensure that we are taking all necessary steps to meet our common needs and goals. Our commitment to work together on energy infrastructure issues will be informed by recent regional energy infrastructure studies conducted by the States, ISO-New England, and other regional organizations. We believe that by working together we can expand economic development, promote job growth, improve the competitiveness of our industries, enhance system reliability, and protect and increase the quality of life of our citizens. Expanding our existing efforts will ensure that we are on a course toward a transformed energy, environment, and economic future for our region that offers a model for the nation.

Signed,

Dannel P. Malloy
Governor of Connecticut

Paul R. LePage
Governor of Maine

Deval L. Patrick
Governor of Massachusetts

Margaret Wood Hassan
Governor of New Hampshire

Lincoln D. Chafee
Governor of Rhode Island

Peter Shumlin
Governor of Vermont

Schedule TJB/JEA-3
Request for Proposals
October 23, 2015

October 23, 2015

To Providers of Gas Infrastructure in New England

On October 2, 2015, The Massachusetts Department of Public Utilities ("MDPU" or the "Department") issued a policy decision in D.P.U. 15-37, authorizing Massachusetts Electric Distribution Companies to propose innovative mechanisms to secure new natural gas capacity for the region to benefit electric customers (the "Order"). The Department determined in the decision that it has the legal authority under G.L. c. 164, § 94A ("Section 94A") to review and approve contracts filed by Electric Distribution Companies for pipeline capacity.

Consistent with the policy statement, Eversource and National Grid are issuing this Request for Proposals to solicit proposals for interstate capacity/gas supplies to further the goals of reduction of the cost of electricity and increasing the reliability of the New England electric system to benefit electric distribution customers. Eversource and National Grid may be referred to herein as "EDCs".

The Department stated in the Order that the Electric Distribution Companies must demonstrate that they have conducted a fair and reasonable procurement to identify potential alternatives (Order at 45). The Department also stated in its Order that the Electric Distribution Company must demonstrate that a proposed agreement results in net benefits for the Mass EDCs' customers and compares favorably to the range of alternative options reasonably available to it at the time of acquisition of the resource or contract negotiation (id).

In keeping with these statements, the Electric Distribution Companies must demonstrate that their proposed contracts and strategies for reducing the costs of electricity for their electric customers is the most appropriate alternative of the range of alternatives that may be leveraged to achieve reduced electricity costs while ensuring reliability for customers. Therefore, this RFP requests proposals

for pipeline expansion projects, LNG supply alternatives, and regional storage projects for that purpose.

If the EDCs determine that proposals submitted in response to this RFP provide the necessary benefits to its retail electricity customers at a reasonable cost, they intend to negotiate with the selected Bidder(s) and to finalize a contract that will be filed with the MDPU for approval. Any such determination would be made individually by EDCs on behalf of their respective Electric Distribution Companies.

Multiple states within New England are considering the procurement of natural gas resources to improve electric supply reliability and to meet other goals. Although this RFP is issued on behalf of EDCs' electric customers, EDCs are committed to working to further the collective interests of the New England States to procure natural gas capacity resources on behalf of customers in the region. To the extent that other States or utilities pursue their own solicitation processes for natural gas resources, and if the goals of such States and utilities are aligned with the goals set forth in this RFP, EDCs may use proposals from this RFP as necessary to coordinate the procurement of natural gas resources to maximize customer benefits. EDCs also generally reserve the right to modify, withdraw and reissue this RFP at any time.

Proposals must be submitted by November 13th, 2015 at 12:00 P.M – EST in accordance with the terms of this RFP.

Sincerely,

James Daly
Vice President Energy Supply
Eversource Energy

John Vaughn
Vice President Energy Procurement
National Grid

NOTICE OF REQUEST FOR PROPOSALS (RFP)

NATURAL GAS CAPACITY, LIQUIFIED NATURAL GAS (LNG), AND NATURAL GAS STORAGE PROCUREMENT

INTRODUCTION

On October 2, 2015, The Massachusetts Department of Public Utilities ("MDPU" or the "Department") issued a policy decision in D.P.U. 15-37, authorizing Massachusetts Electric Distribution Companies to propose innovative mechanisms to secure new natural gas capacity for the region to benefit electric customers (the "Order"). The Department determined in the decision that it has the legal authority under G.L. c. 164, § 94A ("Section 94A") to review and approve contracts filed by Electric Distribution Companies for pipeline capacity. The Department also established a standard of review for such contracts and identified the filing requirements for such proposals.

Consistent with the policy statement, Eversource and National Grid are issuing this Request for Proposals to solicit proposals for interstate capacity/gas supplies to further the goals of reduction of the cost of electricity and increasing the reliability of the New England electric system to benefit electric distribution customers. Eversource and National Grid may be referred to herein as "EDCs".

The Department stated in the Order that the Electric Distribution Companies must demonstrate that they have conducted a fair and reasonable procurement to identify potential alternatives (Order at 45). The Department also stated in its Order that the Electric Distribution Company must demonstrate that a proposed agreement compares favorably to the range of alternative reliable and least cost resource options reasonably available to it at the time of acquisition or contract negotiation (id). In keeping with these statements, the Electric Distribution Companies must demonstrate that their proposed contracts and strategies for reducing the costs of electricity for their electric customers is the most appropriate alternative of the range of alternatives that may be leveraged to achieve reduced electricity costs while ensuring reliability for customers. Therefore, this RFP requests proposals for pipeline expansion projects, LNG supply alternatives, and regional storage projects for that purpose.

BACKGROUND

If the EDCs determine that proposals submitted in response to this RFP are commercially reasonable and sufficiently sized to address region-wide electric supply cost and reliability concerns, they intend to negotiate with the selected Bidder(s) and to finalize a contract that will be filed with the MDPU for approval. Any such determination would be made individually by EDCs on behalf of their respective Electric Distribution

Companies. It is anticipated that any contract(s) filed for approval with the MDPU would contain cost support of the associated proposed project(s) reflective of the cost that would apply to MA EDCs electric distribution customers based on such customers share of New England region-wide load.

Multiple states within New England are considering the procurement of natural gas resources to improve electric supply reliability and to meet other goals. Although this RFP is issued on behalf of EDCs' electric customers, EDCs are committed to working to further the collective interests of the New England States to procure natural gas capacity resources on behalf of customers in the region. To the extent that other States or utilities pursue their own solicitation processes for natural gas resources, and if the goals of such States and utilities are aligned with the goals set forth in this RFP, the EDCs may revise this RFP as necessary to coordinate the procurement of natural gas resources to maximize customer benefits. The EDCs also generally reserve the right to modify, withdraw and reissue this RFP at any time.

PROPOSAL DEADLINE

Proposals must be submitted by November 13th, 2015 at 12:00 P.M – EST. **Applications or supporting documents received after that date and time will not be considered.**

A. OBJECTIVE OF RFP

The primary objective of this RFP is to identify cost-effective resources that would function to increase the reliability of electric service and reduce electric costs for the benefit of the EDCs' electric customers. The primary firm gas supply resources solicited in this RFP are intended to be utilized by gas-fired generators in the New England region to improve regional electric supply reliability and lower the regional cost of retail electricity in substantial and timely manner. Currently there are inadequate gas supplies and transportation infrastructure to meet generation requirements, which threatens the reliability of the grid, especially during cold winter weather. This RFP is designed to identify alternatives for alleviating those constraints and improving winter electric supply reliability at the lowest cost for customers, by allowing the EDCs to contract for primary firm natural gas resources, which may include Natural Gas Capacity, LNG, and/or Natural Gas Storage for the benefit of customers. Capacity and/or storage rights will be released by the EDCs to gas-fired generators for the purpose of ensuring a reliable supply of natural gas to power generation. The EDCs intend to have competitive bidding for capacity releases.

B. REQUIREMENTS

Each proposal is required to address all of the following:

1. Delivery and Receipt locations: Provide physical locations where natural gas will

be delivered to and transported from, including but not limited to a description of the upstream supplies that would support the proposed resource. For pipeline project proposals, Bidders should discuss the liquidity at proposed receipt points as well as any known pipeline constraints upstream of such receipt points. For LNG proposals, Bidders should discuss the source of LNG supply including the country(ies) of origin and mode of transportation. Specifically, Bidders must supply a list of power generators within New England for which the delivery of primary firm gas supply is possible under the proposal, including identification of the volumes of gas than can be delivered to each facility under peak demand conditions. Bidders are responsible for the development of incremental infrastructure for the delivery of natural gas to generators in New England on a primary firm basis. A bidder shall submit receipt and delivery point MDQs. Bidders are encouraged to provide delivery point flexibility to the extent possible such that volumes of gas can be delivered to multiple generators within operational segments of the pipeline.

Given that the objective of this RFP is to benefit regional electric customers, Bidders are required to demonstrate that the proposal will provide reliable delivery of natural gas on a primary firm basis to multiple generating facilities on critical peak days across multiple load zones. Preference will be given to proposals that provide incremental delivery capacity that are most likely to yield substantial regional benefits to New England electric customers on an efficient, reliable and sustainable basis.

2. Service Type and Operational Flexibility: Bidder should indicate the type of service that will be provided and a detailed explanation of the operational flexibility afforded by the respective resource. The explanation of operational flexibility should set forth how the proposed project or service offering can meet the needs of gas-fired generation that frequently runs at a higher level during specific hours of the day (i.e. on-peak hours). The project or existing facility must be able to demonstrate that it can provide the required natural gas on a primary firm basis to generator delivery meters for the duration of the contract.

3. Quantity: EDCs may procure up to their respective load share of regional power demand for the natural gas resources, but the total quantity of natural gas resources purchased in the region through the expansion of this RFP and/or complimentary procurement processes undertaken by other States and utilities would not exceed 2,000,000 MMBtu/day nor shall be any individual project be less than 500,000 MMBtu/day. Accordingly, alternative proposals may be submitted for alternative total project facility and size configurations. Bidders should identify which generation facilities can be served at different levels of discrete investment. The proposal and each supply configuration should clearly delineate: i) the total project size; ii) the quantity already committed to other parties (via contracts, precedent agreements or other mechanisms); iii) the quantity, or range of quantities, offered to other entities; and, iv) the minimum quantity or range of quantities required to make each facility configuration

economically viable. There is no limit to the number of alternate quantity proposals that may be included, but Bidders must clearly specify any implications to the proposed project, including but not limited to schedule and rate impacts associated with such scaling. Bidders should identify all service commencement dates applicable to all quantity proposals, including the quantity and associated service commencement date, as well as associated receipt and delivery points, specific to each phase of any proposals consisting of a multi-phased implementation of service.

Bids for LNG and storage must include both the MDQ and maximum annual quantity of commodity or storage space and indicate the extent to which reinjection can take place during the winter season. Bids including a liquefaction/injection component must also specify the point at which natural gas must be tendered for firm injection. Bids for LNG and storage must also include transportation via interstate pipeline to generators in New England on a primary firm basis.

4. Price: Each Bidder is required to provide the price of the resource, including but not limited to any fixed or variable charges that the customer would incur by executing a contract with the selected bidder. All Bids must specify the maximum rate to be charged for the services offered. Any bids based on cost of service must also specify a cap (maximum rate). Bidders must identify all relevant pricing terms including relevant price indices. In order to facilitate potential coordination in other states in which the EDCs New England affiliates offer distribution service, any bid must be applicable for incorporation into Precedent Agreements that may be submitted for regulatory approval in such states. Bidders are required to maintain all offers firm through December 31, 2015. Beyond such date, winning bid(s) are anticipated to be incorporated into an executed Precedent Agreement(s) subject to the terms and conditions therein.

5. Contract Term and Renewal Rights: Bidders are required to identify the expected in-service date of all Proposals as well as a guaranteed in-service date. Bidders are also required to specify the minimum required term (not less than 15 years but not to exceed 20 years) as well as corresponding renewal rights.

6. Pro-forma Contract/Precedent Agreements: Each Bidder is required to submit a contract or precedent agreement applicable and appropriate to the type of resource offered. A pro-forma precedent agreement is attached in Exhibit 1. Bidders who have not already tendered a form agreement must include a marked version showing any proposed changes to the Pro-forma Contract / Precedent Agreement with their bid, and it is assumed that Bidders would be willing to execute the marked-up pro-forma Contract/Precedent Agreement included in their bids. Alternatively, Bidders may provide a form of precedent agreement that has been approved previously by the MDPU or other New England jurisdiction with any markup changes proposed for a project bid under this RFP. Bidders are discouraged from proposing material changes to the Pro-forma

Contract/Precedent Agreements. A Natural Gas Base Contract is attached in Exhibit B, which represents standard terms and provisions from the North American Energy Standards Board, Inc. (NAESB), for contracting for Natural Gas supplies. Additional Special Provisions have been outlined in Exhibit B, and EDCs reserve the right to further update all contract provisions, including but not limited to those related to financial parameters, legal proceedings, warranties, terminations and force majeure.

7. Tariffs and Pro-forma Service Agreements: Bidders should submit existing and proposed Tariffs and Pro-forma Service agreements. Bidders that are submitting proposals for LNG and Natural Gas Storage should submit Tariffs and Pro-forma Service agreements as well. Pipelines, LNG, and Natural Gas Storage Bidders should also submit provisions, if any, for No-Notice Service.

8. Documentation of Experience with development and management of natural gas resources: Bidders are required to document their experience in developing and managing natural gas resources, identifying the scope of the activities for which they were responsible, the companies they served, and the periods in which the services were provided. Bidders are requested to highlight their experience in the northeastern US market.

9. Regulatory/Siting/Approvals/Timing: Bidders are required to list all regulatory/siting approvals necessary from agencies at the Federal, State and Municipal levels that will be required for the proposed resource.

   Bidders are required to itemize all of the physical assets and/or facilities that are required to provide the services proposed in response to this RFP, including a list of all permits required (to the extent not already obtained). Preference will be given to those bidders that can provide the expected benefits in a timely manner and with the highest probability of success.

10. Audited Financial Statements, Annual Reports, and Credit Ratings. Bidders should provide a copy of their audited financial statements with notes for at least the past three years and their most recent annual report with management's discussion and analysis. Bidders should also provide documentation of their current credit ratings from Moody's Investor Services, Standard and Poor's, or Fitch Ratings. Preference will be given to entities with a credit rating of investment grade or above and with a positive outlook.

11. Business Condition and Financial Reports: Bidders shall provide an overview of their firm, including corporate profile, ownership structure, and financial condition. Bidders should include how the project or service will be financed or supported, including but not limited to the financial instruments and structures the company will utilize in both development and operation of its resource proposal. Bidders should also be prepared to provide other relevant information relating to their

qualifications, business and operations. Preference will be given to entities with substantial, proven operating experience and financial strength in providing the services offered under this RFP.

12. Disclosure of Legal Matters and Conflicts of Interest: Bidders shall provide details of any claims, disputes, litigation, FERC, SEC or state regulatory action, enforcement action, investigation or other legal proceedings relating to their firm or individual personnel referenced in the proposal (in their business capacity) in the three preceding years. Describe any activities or relationships in which the Bidder or its personnel are engaged with the EDCs or their affiliates, or which may constitute a conflict of interest in providing the services to the EDCs, and any claims or disputes with EDCs or any of their affiliates.

C. PROCEDURES AND BIDDER CERTIFICATION

All communications pertaining to this Notice must be submitted via e-mail with the subject line "EDC Pipeline Capacity/Supply Procurement" to the following:

Eversource:

Edna Karanian at: edna.karanian@eversource.com
Eric Soderman at: eric.soderman@eversource.com

National Grid:

John Allocca at: John.Allocca@nationalgrid.com
Timothy Brennan at: TIMOTHY.J.BRENNAN@nationalgrid.com
Samara Jaffe at: Samara.Jaffe@nationalgrid.com

The following is the schedule (subject to change) for this RFP process:

Issue RFP	October 23, 2015
Bidder questions deadline	October 30, 2015
Proposals Due	November 13, 2015

SUBMISSION REQUIREMENTS

Responses to this RFP must be made in writing and be made by mail and electronically. All electronic and hardcopy proposals must be received by November 13th, 2015 at 12:00PM Eastern Time. EDCs will not accept by mail any proposal from a bidder sent as a follow up to its email proposal that differs from its email proposal.

Each proposal shall contain the full name and business address of the bidder

and bidder's contact person and shall be signed by an authorized representative of the bidder. Each proposal must be submitted by an authorized representative of the bidder, and by its submission of its bid the bidder certifies that:

- The bidder has reviewed the RFP and all attachments and has investigated and informed itself with respect to all matters pertinent to the RFP and its proposal;

- The bidder's proposal is submitted in compliance with all applicable federal, state and local laws and regulations, including antitrust and anti-corruption laws;

- Each bid is being bid independently and that it the bid was prepared without knowledge of the substance of any other proposal being submitted by a non-affiliated bidder in response to this RFP;

- The bidder has not disclosed and will not disclose prior to any award hereunder, any information relating to its proposal which could have an effect on whether another bidder submits a proposal to this RFP, or on the contents of such proposal that another bidder would be willing to submit in response to this RFP, which may include, as an example, the fact that the bidder is submitting a proposal in response to this RFP, the bidder's proposal[s], the quantities of each product bid, the bidder's estimation of the value of a product, the bidder's estimation of the risks associated with supplying a product, and the bidder's preference for bidding on one or several products; and

- The bidder has bound any agents, consultants or other third parties retained or otherwise used in connection with the preparation and submission of its proposal to observe these same restrictions and requirements concerning its proposal and maintain the confidentiality of information concerning its proposal.

EDCs shall have the exclusive right to select or reject any or all of the proposals submitted at any time, for any reason. EDCs may also disregard any bid submission not in accordance with the requirements contained in this RFP. Further, EDCs expressly reserve the right, in their sole and absolute discretion (exercised individually), to seek clarifications of any submissions, to seek modifications to any submissions, to unilaterally change the schedule described herein or modify any of the rules and procedures set forth herein or subsequently issued, to terminate the process described herein, and to invite any (or none) of the Respondents to participate further in the process, all without prior notice.

D. CONFIDENTIALITY

Bidder and EDCs agree to use commercially reasonable efforts to maintain the confidentiality of the Bidder's proposal. However, it is understood by all parties that any contract resulting from this procurement will need to be filed by EDCs for approval with the MDPU. The EDCs will also be required to disclose the details of any contract to their respective consultants as part of the analysis for these filings. It is also understood that a resulting contract may be filed or disclosed by a Bidder as part of the Bidder's regulatory filing and approval process. The confidentiality of commercially sensitive documents required to be filed at the MDPU or in other regulatory proceedings will be governed by applicable laws and regulations.

E. EVALUATION OF PROPOSALS AND SELECTION PROCESS

Once proposals are received, the proposals will be subject to a review, evaluation and selection process.

In order to obtain approval by the MDPU, an EDC must demonstrate that the proposed contract (1) results in net benefits for the Massachusetts Electric Distribution Company's customers at a reasonable cost, and (2) compares favorably to the range of alternative options reasonably available to the Electric Distribution Company at the time of acquisition of the resource or contract negotiation. An Electric Distribution Company must show that the price of the resource is competitive and that the contract satisfies other non-price factors such as reliability of service and diversity of supply. D.P.U. 15-37, October 2, 2015, p.43-44. Any selected Bidder is expected to fully support EDCs in their efforts to satisfy these requirements in order to receive MDPU approval.

All proposals will be evaluated on the price and non-price factors consistent with applicable MDPU policies, decisions and precedents.

F. REGULATORY APPROVAL

Any contract developed by the parties will be filed for approval with the MDPU and will not become effective unless approved by the MDPU. Should responses to this RFP be of a scale requiring approvals of related contracts in other states, Bidders agree to support the pursuit of regulatory approvals in those states. It is possible that the MDPU may condition approval of any contract that results from this RFP on approvals of related contracts in other states.

EXHIBIT A

Precedent Agreement

PRECEDENT AGREEMENT

This PRECEDENT AGREEMENT ("Precedent Agreement") is made and entered into this ___ day of _____, 2015 ("Effective Date"), by and between [TRANSPORTER], [STATE] [ENTITY TYPE] ("Transporter"), and [SHIPPER], a [STATE] [ENTITY TYPE] ("Shipper"). Transporter and Shipper are sometimes referred to individually as a "Party" and collectively as the "Parties."

W I T N E S S E T H:

WHEREAS, Transporter owns and operates an interstate natural gas transmission system in (specify STATES);

WHEREAS, Shipper desires that Transporter expand such interstate natural gas transmission system and purchase firm natural gas transmission service under (insert applicable Tariff existing/new) in connection with the _____Project (the "Project");

WHEREAS, subject to the terms and conditions of this Precedent Agreement, Transporter is willing to construct the Project and provide the firm transportation service that Shipper desires;

NOW, THEREFORE, in consideration of the mutual covenants herein assumed, and intending to be legally bound, Transporter and Shipper agree as follows:

1. Transporter Obligations.

   a) Subject to the terms and conditions of this Precedent Agreement, Transporter shall proceed with due diligence to obtain from all governmental and regulatory authorities authorizations necessary[y: (i)] for Transporter to construct, install, own, operate, and maintain the Project facilities, and, if applicable, abandon existing facilities, necessary to provide the firm transportation service

contemplated herein ("Transporter's Authorizations")[, and (ii) for Transporter to perform its obligations as contemplated in this Precedent Agreement, including the obligation to seek authorization from the Federal Energy Regulatory Commission ("FERC") for receipt point flexibility as described in the following sentence.] [Placeholder - To be further defined] Furthermore, Transporter agrees to seek any necessary authorization or waiver from FERC that may be required to allow Shipper to release capacity to electric generators on a preferential basis.

b) Transporter reserves rights to (i) file and prosecute any and all applications for such authorizations and, (ii) request for rehearing or court review, that are consistent with this Precedent Agreement, the FTSA (defined below in Paragraph 3) and the Negotiated Rate Agreement (in the form attached as Attachment A-2 hereto ("Negotiated Rate Agreement").

c) Transporter agrees to (i) provide Shipper with an opportunity to review and comment on the text of Transporter's FERC application, before filing, and shall, in good faith, work with Shipper to address any concerns raised by Shipper with respect to such application, (ii) promptly notify Shipper in writing when each of Transporter's Authorizations is received, obtained, rejected or denied and, (ii) promptly notify Shipper in writing as to whether a Transporter Authorization that has been received or obtained is acceptable to Transporter.

d) During the term of this Precedent Agreement, Transporter agrees to use reasonable efforts to support and cooperate with, and to not oppose, obstruct or otherwise interfere with, Shipper in Shipper's efforts to obtain

Shipper Authorizations as referenced below. The term of the Precedent Agreement will commence on the Effective Date and continue until the Precedent Agreement is terminated.

2. Shipper Obligations.

a) Subject to the terms and conditions of this Precedent Agreement, Shipper shall proceed with due diligence to obtain all necessary and appropriate authorizations and approvals from governmental and regulatory authorizations necessary for Shipper to perform its obligations as contemplated in this Precedent Agreement, the FTSA and the Negotiated Rate Agreement referenced in this agreement as ("Shipper's Authorizations").

b) Shipper reserves the right to file and prosecute applications for Shipper Authorizations, and any court review, if necessary, in a manner it deems to be in its best interest. Shipper agrees to promptly notify Transporter in writing when each of Shipper Authorizations is received, obtained, rejected or denied.

c) Shipper shall promptly notify Transporter in writing as to whether each of Shipper Authorizations that has been received or obtained is acceptable to Shipper.

d) During the term of this Precedent Agreement, Shipper agrees to use reasonable efforts to support its obligations as contemplated by this Precedent Agreement. Nothing herein shall be construed to limit or waive Shipper's rights to intervene or protest any filing by Transporter to the extent Shipper determines in good faith that such filing is not consistent with Transporter's obligations or Shipper's rights under this Precedent Agreement, the FTSA or the Negotiated Rate Agreement.

3. Firm Transportation Service Agreement ("FTSA").

a) FTSA. Subject to the conditions set forth herein, Shipper and Transporter agree that no later than XXX (to be specified) days following the date on which the FERC issues an order granting Transporter a certificate of public convenience and necessity to construct the Project facilities to allow Transporter to commence the construction of the Project (or such other mutually agreed date) Transporter and Shipper will execute the FTSA in the form attached as Attachment A-1 hereto under Rate Schedule _____ which (i) specifies a Maximum Daily Quantity ("MDQ") of XX,XXX Dth/d, exclusive of fuel requirements, effective on the Service Commencement Date (as determined in accordance with Paragraph 4 of this Precedent Agreement), (ii) specifies a primary term of [_____ (XX)] years commencing on the Service Commencement Date ("Primary Term"), (iii) specifies Primary Point(s) of Receipt at [_____] and a Maximum Daily Receipt Quantity ("MDRQ") of XX,XXX Dth/d; (iv) specifies the following Primary Points of Delivery and Maximum Daily Delivery Quantities ("MDDQ*"): [location description and meter number(s)];* and (v) incorporates the terms of the Negotiated Rate Agreement (the "FTSA"). (vi) Project shall provide details of any proposed Hourly flexibility. Transporter will accept its FERC certificate of public convenience and necessity to construct the Project facilities no later than TBD days after the execution of the FTSA between Transporter and Shipper.

b) Rate. Transporter and Shipper further agree that they will execute, in accordance with Transporter's Tariff, the Negotiated Rate Agreement, consistent with the terms of this Precedent Agreement, as set forth on Attachment A-2 hereto, subject to approval by the FERC, which shall become effective on the Service Commencement Date.

c) Primary Term Extension. Not less than X months prior to the end of the Primary Term, Shipper may, at its option, extend the Primary Term for up to 100% of the MDQ for TBD years (each a "Primary Term Extension"). The applicable rates during the term of such extension shall be as set forth in the Negotiated Rate Agreement.

d) Renewal. Shipper shall have an evergreen right to extend the term of the FTSA after the end of the Primary Term or the Primary Term Extension for all or any portion of the MDTQ at the then-effective rate set forth in the Negotiated Rate Agreement, subject to Shipper providing Transporter written notice at least _____ (TBD) months prior to the end of the Primary Term or Primary Term Extension, as applicable, and subject to the right of first refusal ("ROFR") provisions as set forth in Transporter's FERC Gas Tariff.

e) Right of First Refusal. Upon Transporter's termination of the FTSA at the end of the Primary Term, Primary Term Extension or annual renewal terms, Shipper shall have a Right of First Refusal pursuant to Transporter's Tariff to be applicable, at Shipper's discretion, to all or a portion of the Shipper's MDTQ, exercisable in accordance with the notice and other applicable provisions of the Tariff.

f) Most Favored Nation Right. Shipper shall have a Most Favored Nation Right as set forth in the Negotiated Rate Agreement.

4. Commencement of Service.

a) Subject to the terms and conditions of this Agreement, Transporter and Shipper agree to execute and deliver the FTSA in accordance with the provisions of Paragraph 3 (FTSA) and subject to the Conditions Precedent stated in this Agreement. Unless Transporter and Shipper amend this Agreement otherwise, service under the Firm Transportation Agreement shall commence no later than [DATE] The Firm Transportation Agreement shall have a primary term ending _____ (XX) years after the Commencement Date (the "Primary Term").

5. Design and Permitting of Project Facilities. Transporter will undertake with due diligence the design of the Project facilities and any other preparatory actions necessary for Transporter to complete and file its application(s) related to the Project with the FERC or other governmental authority as appropriate.

6. Construction of Project. Upon satisfaction of the conditions precedent set forth in Paragraphs 7 of this Precedent Agreement, or written waiver of the same by Transporter or Shipper, as applicable, Transporter shall proceed with due diligence to complete construction of the authorized Project facilities to implement the firm transportation service contemplated in this Precedent Agreement by [DATE].

7. Conditions Precedent. Commencement of service under the FTSA and Transporter's and Shipper's rights and obligations under the FTSA are expressly made subject to satisfaction of the following conditions precedent in this

Paragraph 7 (only Transporter shall have the right to waive the conditions precedent set forth in Paragraph 7(a) and only Shipper shall have the right to waive the conditions precedent set forth in Paragraph 7(b)):

a) Transporter's Conditions Precedent.

i. Transporter's receipt of approval, on or before [Date], from its Board of Directors, or similar governing body, to construct the Project facilities and/or to execute the FTSA;

ii. Transporter's receipt, on or before [Date], of all Transporter's Authorizations pursuant to Paragraph 1;

iii. Transporter's procurement, on or before [Date], of all rights-of-way, easements or permits necessary for the construction and operation of the Project facilities;

iv. Transporter's completion of construction of the Project facilities and all other facilities required to render firm transportation service for Shipper pursuant to the FTSA, on or before [DATE]

b) Shipper's Conditions Precedent.

i. Shipper's receipt of approval, on or before [DATE], from its Board of Directors, or similar governing body, to participate in the Project;

ii. Shipper's receipt and acceptance by [DATE], of any necessary Shipper Authorizations identified in accordance with Paragraph 2 of this Precedent Agreement;

iii. Transporter's receipt by [DATE] of Transporter's Authorizations to provide the firm transportation service on the terms contemplated herein and in

the FTSA and the Negotiated Rate Agreement, and to perform its other obligations contemplated herein; and

iv. Transporter's completion of construction of the Project facilities and all other facilities required to render firm transportation service for Shipper pursuant to the FTSA, on or before [DATE]

v. Receipt of Authorization from the FERC on or before [DATE] allowing Shipper to release capacity to electric generators on a preferential basis.

c) With respect to each condition precedent set forth in Paragraph 7(a) of this Precedent Agreement, Transporter shall use commercially reasonable efforts to provide notice to Shipper within (TBD) days of the date that such condition precedent has been satisfied or waived. With respect to the conditions precedent set forth in Paragraphs 7(b)(i) and (ii) of this Precedent Agreement, Shipper shall use commercially reasonable efforts to provide notice to Transporter that such condition precedent has been satisfied or waived.

d) Unless otherwise provided for herein, Transporter's Authorizations contemplated in Paragraph 1 of this Precedent Agreement and otherwise associated with the FTSA and Negotiated Rate Agreement contemplated by this Precedent Agreement must be issued in form and substance reasonably satisfactory to both Parties hereto; provided that this Paragraph 7(d) does not give rise to a termination right for either Party independent of Transporter's termination right pursuant to Paragraphs 9(a) and 10(a) or Shipper's termination right pursuant to Paragraphs 9(b) and 10(b) hereof. Transporter shall provide written notice to Shipper not later than (TBD) days after issuance of any of Transporter's

Authorizations, and shall offer to meet with Shipper promptly upon the issuance of any such authorization(s) to discuss any concerns or issues related thereto. For purposes of this Precedent Agreement, Transporter's Authorizations shall be deemed satisfactory to Shipper if such Authorizations are consistent with the terms of this Precedent Agreement, the FTSA and the Negotiated Rate Agreement and do not impose conditions or obligations that adversely affect Shipper. To the extent Shipper determines in Shipper's sole reasonable judgment that the Transporter's Authorizations do not satisfy the requirements of the immediately preceding sentence, Shipper shall notify Transporter in writing not later than (TBD) days after receipt of Transporter's notice of such Authorizations, and shall detail the basis of such determination. Designated representatives of the Parties shall meet promptly and negotiate in good faith to reach mutual agreement on a reasonable modification or an agreeable alternative to address the unsatisfactory elements of such Authorizations, and each Party agrees to discuss in good faith any positions advanced by the other Party in accordance with the foregoing. All other governmental authorizations, approvals, permits and/or exemptions that Transporter must obtain must be issued in form and substance reasonably acceptable to Transporter. All governmental approvals that Transporter is required by this Precedent Agreement to obtain must be duly granted by the FERC or other governmental agency or authority having jurisdiction, and must be final and no longer subject to rehearing or appeal; provided, however, Transporter may waive the requirement that such authorization(s) and approval(s) be final and no longer subject to

rehearing or appeal. Transporter shall provide quarterly updates to Shipper regarding Transporter's progress in obtaining Transporter's Authorizations.

8. Limitation of Liability. NEITHER PARTY HERETO SHALL BE LIABLE FOR INCIDENTAL, SPECIAL, CONSEQUENTAL, PUNITIVE, EXEMPLARY, OR INDIRECT DAMAGES, BY STATUTE, IN TORT OR CONTRACT OR OTHERWISE.

9. Termination of Precedent Agreement for Failure of Conditions Precedent

   a) If the conditions precedent set forth in Paragraph 7(a) of this Precedent Agreement have not been fully satisfied or waived by Transporter by the applicable dates specified therein or the Service Commencement Dates have not occurred by [DATE], and this Precedent Agreement has not been terminated pursuant to Paragraphs 10 or 11 hereof, then Transporter–may thereafter terminate this Precedent Agreement (and the FTSA, if executed), by providing (TBD) days' prior written notice of its intention to terminate to Shipper; provided, however, if the conditions precedent are satisfied, or waived by Transporter within such (TBD) day notice period, then termination notice of such agreements will be null and void. Transporter's termination right pursuant to this Paragraph 9(a) expires if it is not exercised within (TBD) days after the deadline giving rise to such termination right. In the event of such termination, Shipper shall have no financial or other obligation to Transporter.

   b) If the conditions precedent set forth in Paragraph 7(b) of this Precedent Agreement have not been fully satisfied or waived by Shipper by the applicable dates specified therein or if Service Commencement Date has not occurred by [DATE] and this Precedent Agreement has not been terminated pursuant to

Paragraphs 10 or 11 hereof, then Shipper may thereafter terminate this Precedent Agreement (and the FTSA, if executed) by providing (TBD) days' prior written notice of its intention to terminate to Transporter; provided, however, if the conditions precedent are satisfied, or waived by Shipper within such (TBD) day notice period (as applicable), then termination of such agreements will not be effective. Shipper's termination right pursuant to this Paragraph 9(b) expires if it is not exercised within (TBD) days after the deadline giving rise to such termination right. In the event of such termination, Shipper shall have no financial or other obligation to Transporter.

10. Additional Termination Rights.

a) Transporter Termination Right. In addition to the provisions of Paragraph 9 hereof, Transporter may terminate this Precedent Agreement (and the FTSA, if executed) by providing written notice of termination to Shipper if: (i) by the earlier of (a) the sixtieth (60^{th}) day following the issuance of the FERC certificate for the Project, provided that no other material Transporter's Authorizations are outstanding, or (b) by [DATE], Transporter, in its sole and reasonable discretion, determines for any reasons that the Project contemplated herein is no longer economically viable; [or (ii) as of [DATE], substantially all precedent agreements, FTSAs or other contractual agreements for the firm service to be made available by the Project are terminated, other than by reason of commencement of service] In the event of such termination, Shipper shall have no financial or other obligation to Transporter.

11. Shipper Termination Right. In the event that (i) Transporter's certificates and authorizations from the FERC are not in form and substance reasonably satisfactory to

Shipper, (ii) Shipper notifies Transporter in writing pursuant to Paragraph 7(d) that such Transporter's certificates and authorizations are not satisfactory, including the basis for such determination, and (iii) Transporter does not receive a subsequent order from the FERC prior to the deadline in Paragraph 7(a)(ii) eliminating such basis and rendering the same reasonable satisfactory to Shipper, Shipper may terminate this Precedent Agreement by providing (TBD) days' prior written notice of its intention to terminate to Transporter; provided that Shipper's termination right pursuant to this Paragraph 10(b) expires if it is not exercised within (TBD) days of the deadline in Paragraph 7(a)(ii). In the event of such termination, Shipper shall have no financial or other obligation to Transporter.

12. Termination upon Service Commencement Date. If this Precedent Agreement is not terminated pursuant to Paragraphs 9 or 10 hereof, then this Precedent Agreement will terminate by its express terms on the Service Commencement Date and thereafter Transporter's and Shipper's rights and obligations related to the transportation service contemplated herein shall be determined pursuant to the terms and conditions of the FTSA, the Negotiated Rate Agreement and Transporter's FERC Gas Tariff, as effective from time to time. Notwithstanding any termination of this Precedent Agreement pursuant to Paragraphs 9, 10 or 11 hereof, or otherwise, to the extent that a provision of this Precedent Agreement contemplates that one or both Parties may have further rights and/or obligations hereunder following such termination, the provision shall survive such termination as necessary to give full effect to such rights and/or obligations.

13. Creditworthiness.

a) In exchange for Transporter's execution of this Agreement, the FTSA, the Negotiated Rate Agreement and any other related agreements, and as a condition precedent to Transporter's obligations pursuant to such agreements, Shipper shall satisfy the following credit assurance provisions as of the effective date of this Agreement, and shall have a continuing obligation to satisfy the credit assurance provisions of this Agreement throughout the term of this Agreement, and such provisions of the FTSA, the Negotiated Rate Agreement and any other related agreements as may be in effect from time to time.

b) Shipper - credit worthiness standards such as: [Shipper's senior unsecured debt or corporate credit rating is at least BBB- (outlook stable) by Standard & Poor's Financial Services LLC ("S&P") and at least Baa3 (outlook stable) by Moody's Investor Service ("Moody's") or equivalent rating from a nationally recognized statistical rating organization, registered with the Securities and Exchange FERC, and acceptable to Transporter; provided, however, that if Shipper is only rated by one agency, then only that rating shall be considered ("Credit Ratings"). For the purpose of this Paragraph 13(b), in the event of a split rating the lower rating applies.]

c) If, at any time, Shipper does not meet the creditworthiness provisions of Paragraph 13(b), then Shipper shall provide to Transporter credit assurance in the form of either a guaranty from a guarantor which meets the creditworthiness standards in Paragraph 13(b), and in a form reasonably acceptable to Transporter, a letter of credit from an institution acceptable to Transporter and in a form reasonably acceptable to Transporter, or a cash security deposit, as

follows: (i) during the first (____) years of the Primary Term an amount equal to (TBD) months of reservation charges, and (ii) at the beginning of year _____ (___) and until the end of the Primary Term, an amount equal to (TBD) months of reservation charges. At end of the Primary Term and all subsequent extension periods, credit assurance (if any) shall then be based on Paragraph_____ of the General Terms & Conditions of Transporter's Tariff.

d) The credit assurance provided to Transporter in this Paragraph 13 shall continue in effect until the earlier of (i) Shipper satisfies the Credit Ratings standards, (ii) the execution of a credit agreement to replace this provision, or (iii) the end of the Primary Term, and full payment of all undisputed balances and charges and resolution of any asserted claims with respect thereto has been made by Shipper.

e) If Shipper does not remedy its failure to demonstrate or furnish acceptable credit assurance as required by this Paragraph 13 within (TBD) days of receipt of written notice of such failure from Transporter, then Transporter shall, in addition to any other remedy available under this Agreement, have the right to terminate this Agreement, the FTSA, and any other related agreements in accordance with the terms of Transporter's Tariff upon (TBD) days written notice to Shipper, provided that such Transporter notice of termination shall be null and void if Shipper has demonstrated or furnished the required credit assurance prior to the expiration of such (TBD) days written notice.

14. Amendments. This Precedent Agreement may not be modified or amended unless the Parties execute written agreements to that effect.

15. Prior Agreements. This Precedent Agreement and its attachments, when executed, supersede all prior agreements and understandings, whether oral or written, with respect to the Project.

16. Successors; Assignments. Any company which succeeds by purchase, merger, or consolidation of title to the properties, substantially as an entirety, of Transporter or Shipper, will be entitled to the rights and will be subject to the obligations of its predecessor in title under this Precedent Agreement. Otherwise, neither Shipper nor Transporter may assign any of its rights or obligations under this Precedent Agreement without the prior written consent of the other Party hereto, provided that such consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, Transporter and Shipper shall each have the right, without obtaining the other Party's consent, to pledge or assign its rights under this Precedent Agreement and/or the FTSA as collateral security for indebtedness incurred by such Party or its affiliate.

17. No Third-Party Rights. Except as expressly provided for in this Precedent Agreement, nothing herein expressed or implied is intended or shall be construed to confer upon or give to any person not a Party hereto any rights, remedies or obligations under or by reason of this Precedent Agreement.

18. Joint Efforts: No Presumptions. Each and every provision of this Precedent Agreement shall be considered as prepared through the joint efforts of the Parties and shall not be construed against either Party as a result of the preparation or

drafting thereof. It is expressly agreed that no consideration shall be given or presumption made on the basis of who drafted this Precedent Agreement or any specific provision hereof

19. Choice of Law. This Precedent Agreement shall be governed by, construed, interpreted, and performed in accordance with the laws of the Commonwealth of Massachusetts without recourse to any laws governing the conflict of laws.

20. Notice. Any notice and/or request provided for in this Agreement or any notice either Party may desire to give to the other shall be transmitted in writing (overnight delivery, U.S. Mail, or electronic mail) such that it is received before (TBD) p.m. time on the due date.

Transporter:

Shipper:

Notice is effective as of the date of confirmed receipt, or, in the absence of confirmed receipt, as of the date actually received.

21. Defined Terms. When used in this Precedent Agreement, and unless otherwise defined herein, capitalized terms shall have the meanings set forth in Transporter's FERC Gas Tariff on file with the FERC, as amended from time to time.

22. Waivers. The waiver by either Party of a breach or violation of any provision of this Precedent Agreement will not operate as or be construed to be a waiver of any subsequent breach or violation hereof.

23. Counterparts. This Precedent Agreement may be executed in any number of counterparts, each of which will be an original, but such counterparts together will constitute one and the same instrument.

24. Headings. The headings contained in this Precedent Agreement are for reference purposes only and shall not affect the meaning or interpretation of this Precedent Agreement.

25. Representations and Warranties. Each Party represents and warrants to each other as follows:

(i) Ability to execute and perform this Precedent Agreement.

(ii) This Precedent Agreement has been duly executed and delivered by such Party.

26. Confidentiality and Disclosures.

(a) The substance and terms of this Precedent Agreement are confidential. Either Party may disclose the substance and terms of this Precedent Agreement to its or its affiliate's directors, officers, employees, representatives, agents, consultants, attorneys or auditors ("Representatives") who have a need to know the substance and terms of this Precedent Agreement. Transporter and Shipper agree not to disclose or communicate, and will cause their respective Representatives not to disclose or communicate, the substance or terms of this Precedent Agreement to any other person, entity, firm, or corporation without the prior written consent of the other Party, provided that either Party may disclose the substance or terms of this Precedent Agreement as required by law, order, rule or regulation of any duly constituted governmental body or official authority having jurisdiction, subject to the condition that the disclosing Party first give the other Party five TBD business days' notice of same or as much notice as possible under the circumstances, so that a protective order or other protective arrangements may be

sought. Notwithstanding the foregoing, the Parties acknowledge that (A) Transporter may, in its sole discretion, exercised reasonably, (i) file a copy of this Precedent Agreement with the FERC under seal in connection with the FERC certificate application, (ii) place on public file with the FERC a description of the terms of any negotiated rate prior to the commencement of firm transportation service under the FTSA, and (iii) use the terms and conditions of this Precedent Agreement (excluding any information proprietary to Shipper) in Transporter's preparation of the pro forma precedent agreement for other Shippers under the Project, and (B) Shipper, in its sole discretion, may provide Project information, including a copy of this Precedent Agreement, to the MDPU; provided Transporter or Shipper will request confidential treatment for any such filing or written disclosure of confidential information. Such filings will not constitute a breach of this confidentiality provision and will not require compliance with the foregoing five TBD day notice provision.

[signature page follows]

27. Execution of Agreement. This Agreement may be executed by the Parties in separate counterparts, each of which when so executed and delivered will be an original, but all such counterparts will together constitute but one and the same instrument.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives as of the date first hereinabove written.

By: _____

Name:_____

Title:_____

By: _____

Name:_____

Title:_____

Attachment A-1
Form of Rate Schedule _____

Firm Transportation Service Agreement

(To be attached)

Attachment A-2
Negotiated Rate Agreement

(To include critical provisions and representations related to rate and other negotiated anchor shipper clauses such as Most Favored Nation ("MFN"), which is intended to provide anchor shipper with longer term economic and service rights protection and benefits)

STATEMENT OF NEGOTIATED RATES (Footnotes)

Shipper Name: [SHIPPER]

FTSA: [INSERT CONTRACT NUMBER]

Term of Negotiated Rate:

Rate Schedule:

MDQ / Dth on the Service Commencement Date

Reservation Rate: Shipper shall pay a negotiated reservation rate of $[___] per Dth, per month of MDQ.

Commodity Charge:

Primary Receipt Point(s):

Primary Delivery Points:

Recourse Rate(s): The Recourse Rate(s) applicable to this service is the applicable maximum rate(s) stated on Transporter's Statement of Rates for Rate Schedule _____ at the applicable time.

FOOTNOTES:

1/ This negotiated rate complies with Transporter's FERC Gas Tariff.

2/ This Negotiated Rate shall apply only to transportation service under this Contract No. [INSERT CONTRACT NUMBER], up to Shipper's specified MDQ, Primary Receipt Point and Primary Delivery Point designated herein, and any secondary receipt and delivery points available under Rate Schedule ____.

3/ Construction cost caps - Bidders must submit how costs will be managed to ensure the best possible rate is achieved. A rate cap is required and a proposal to address construction cost under- and over-runs if construction of facilities are necessary.

4/ Notice Provisions - Proposals should include details on applicable notice provisions

5/ Transporter and Shipper agree that Contract No. [INSERT CONTRACT NUMBER] is a ROFR Agreement.

6/ Shipper shall pay a commodity charge which shall be (TBD).

7/ Renewal rates are described: Bidders should provide a description of renewal rate options at the end of the primary term.

8/ Most Favored Nations (MFN)

Designed and included to protect project anchor shippers' economic position, in the event future projects are constructed and/or capacity is sold using the Projects' assets and resulting in a lower rate than the negotiated rate paid by anchor shippers.

1. Identifies applicable project capacity, length of time such MFN is in effect, mechanism by which projects are compared and the resulting reduction in anchor shippers' Negotiated Rate, if a subsequent project is determined to render a lower rate.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives as of the date first hereinabove written.

By: _____

Name:_____

Title:_____

By: _____

Name:_____

Title:_____

EXHIBIT B

North American Energy Standards Board, Inc.

Natural Gas Base Contract

Base Contract for Sale and Purchase of Natural Gas

This Base Contract is entered into as of the following date: _____

The parties to this Base Contract are the following:

PARTY A	*PARTY NAME*	PARTY B
	ADDRESS	
	BUSINESS WEBSITE	
	CONTRACT NUMBER	
	D-U-N-S® NUMBER	
☐ US FEDERAL: ☐ OTHER	*TAX ID NUMBERS*	☐ US FEDERAL: ☐ OTHER:
Delaware	*JURISDICTION OF ORGANIZATION*	
☐ Corporation ☐ LLC ☐ Limited Partnership ☐ Partnership ☐ LLP ☐ Other_____	*COMPANY TYPE*	☐ Corporation ☐ LLC ☐ Limited Partnership ☐ Partnership ☐ LLP ☐ Other_____
	GUARANTOR (IF APPLICABLE)	
CONTACT INFORMATION		
_____ *ATTN* _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____	▪ *COMMERCIAL*	_____ *ATTN* _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____
_____ *ATTN* _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____	▪ *SCHEDULING*	_____ *ATTN* _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____
_____ *ATTN* _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____	▪ *CONTRACT AND LEGAL NOTICES*	_____ *ATTN* _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____
ATTN _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____	▪ *CREDIT*	*ATTN* _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____
ATTN _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____	▪ *TRANSACTION CONFIRMATIONS*	*ATTN* _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____
ACCOUNTING INFORMATION		
ATTN _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____	▪ *INVOICES* ▪ *PAYMENTS* ▪ *SETTLEMENTS*	*ATTN* _____ *TEL#:* _____ *FAX#:* _____ *EMAIL:* _____
BANK: _____ *ABA:* _____ *ACCT:* _____ *OTHER DETAILS:* _____	*WIRE TRANSFER NUMBERS (IF APPLICABLE)*	*BANK:* _____ *ABA:* _____ *ACCT:* _____ *OTHER DETAILS:* _____
ATTN: _____ *ADDRESS:* _____	*CHECKS (IF APPLICABLE)*	*ATTN:* _____ *ADDRESS:* _____
BANK: _____ *ABA:* _____ *ACCT:* _____ *OTHER DETAILS:* _____	*ACH NUMBERS (IF APPLICABLE)*	*BANK:* _____ *ABA:* _____ *ACCT:* _____ *OTHER DETAILS:* _____

Base Contract for Sale and Purchase of Natural Gas

(Continued)

This Base Contract incorporates by reference for all purposes the General Terms and Conditions for Sale and Purchase of Natural Gas published by the North American Energy Standards Board. The parties hereby agree to the following provisions offered in said General Terms and Conditions. In the event the parties fail to check a box, the specified default provision shall apply. Select the appropriate box(es) from each section:

Section 1.2 Transaction Procedure ☐ Oral (default) OR ☐ Written	**Section 10.2** Additional Events of Default ☐ No Additional Events of Default (default) ☐ Indebtedness Cross Default ☐ Party A: _____ ☐ Party B: _____ ☐ Transactional Cross Default Specified Transactions:
Section 2.7 Confirm Deadline ☐ 2 Business Days after receipt (default) OR ☐ ____ Business Days after receipt	
Section 2.8 Confirming Party ☐ Seller (default) OR ☐ Buyer ☐ _____	
Section 3.2 Performance Obligation ☐ Cover Standard (default) OR ☐ Spot Price Standard	**Section 10.3.1** Early Termination Damages ☐ Early Termination Damages Apply (default) OR ☐ Early Termination Damages Do Not Apply
Note: The following Spot Price Publication applies to both of the immediately preceding.	**Section 10.3.2** Other Agreement Setoffs ☐ Other Agreement Setoffs Apply (default) ☐ Bilateral (default) ☐ Triangular OR ☐ Other Agreement Setoffs Do Not Apply
Section 2.31 Spot Price Publication ☐ Gas Daily Midpoint (default) OR ☐ _____	
Section 6 Taxes ☐ Buyer Pays At and After Delivery Point (default) OR ☐ Seller Pays Before and At Delivery Point	
Section 7.2 Payment Date ☐ **25th Day** of Month following Month of delivery (default) OR ☐ Day of Month following Month of delivery	**Section 15.5** Choice Of Law _____
Section 7.2 Method of Payment ☐ Wire transfer (default) ☐ Automated Clearinghouse Credit (ACH) ☐ Check	**Section 15.10** Confidentiality ☐ Confidentiality applies (default) OR ☐ Confidentiality does not apply
Section 7.7 Netting ☐ Netting applies (default) OR ☐ Netting does not apply	
☐ **Special Provisions** Number of sheets attached: ___(___)_ ☐ **Addendum(s):** _____	

IN WITNESS WHEREOF, the parties hereto have executed this Base Contract in duplicate.

	PARTY NAME	
By: _____	***SIGNATURE***	**By:** _____
Name:	***PRINTED NAME***	**Name:** _____
Its:	***TITLE***	**Title:** _____

General Terms and Conditions
Base Contract for Sale and Purchase of Natural Gas

SECTION 1. PURPOSE AND PROCEDURES

1.1. These General Terms and Conditions are intended to facilitate purchase and sale transactions of Gas on a Firm or Interruptible basis. "Buyer" refers to the party receiving Gas and "Seller" refers to the party delivering Gas. The entire agreement between the parties shall be the Contract as defined in Section 2.9.

The parties have selected either the "Oral Transaction Procedure" or the "Written Transaction Procedure" as indicated on the Base Contract.

Oral Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Any Gas purchase and sale transaction may be effectuated in an EDI transmission or telephone conversation with the offer and acceptance constituting the agreement of the parties. The parties shall be legally bound from the time they so agree to transaction terms and may each rely thereon. Any such transaction shall be considered a "writing" and to have been "signed". Notwithstanding the foregoing sentence, the parties agree that Confirming Party shall, and the other party may, confirm a telephonic transaction by sending the other party a Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means within three Business Days of a transaction covered by this Section 1.2 (Oral Transaction Procedure) provided that the failure to send a Transaction Confirmation shall not invalidate the oral agreement of the parties. Confirming Party adopts its confirming letterhead, or the like, as its signature on any Transaction Confirmation as the identification and authentication of Confirming Party. If the Transaction Confirmation contains any provisions other than those relating to the commercial terms of the transaction (i.e., price, quantity, performance obligation, delivery point, period of delivery and/or transportation conditions), which modify or supplement the Base Contract or General Terms and Conditions of this Contract (e.g., arbitration or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 1.3 but must be expressly agreed to by both parties; provided that the foregoing shall not invalidate any transaction agreed to by the parties.

Written Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Should the parties come to an agreement regarding a Gas purchase and sale transaction for a particular Delivery Period, the Confirming Party shall, and the other party may, record that agreement on a Transaction Confirmation and communicate such Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means, to the other party by the close of the Business Day following the date of agreement. The parties acknowledge that their agreement will not be binding until the exchange of nonconflicting Transaction Confirmations or the passage of the Confirm Deadline without objection from the receiving party, as provided in Section 1.3.

1.3. If a sending party's Transaction Confirmation is materially different from the receiving party's understanding of the agreement referred to in Section 1.2, such receiving party shall notify the sending party via facsimile, EDI or mutually agreeable electronic means by the Confirm Deadline, unless such receiving party has previously sent a Transaction Confirmation to the sending party. The failure of the receiving party to so notify the sending party in writing by the Confirm Deadline constitutes the receiving party's agreement to the terms of the transaction described in the sending party's Transaction Confirmation. If there are any material differences between timely sent Transaction Confirmations governing the same transaction, then neither Transaction Confirmation shall be binding until or unless such differences are resolved including the use of any evidence that clearly resolves the differences in the Transaction Confirmations. In the event of a conflict among the terms of (i) a binding Transaction Confirmation pursuant to Section 1.2, (ii) the oral agreement of the parties which may be evidenced by a recorded conversation, where the parties have selected the Oral Transaction Procedure of the Base Contract, (iii) the Base Contract, and (iv) these General Terms and Conditions, the terms of the documents shall govern in the priority listed in this sentence.

1.4. The parties agree that each party may electronically record all telephone conversations with respect to this Contract between their respective employees, without any special or further notice to the other party. Each party shall obtain any necessary consent of its agents and employees to such recording. Where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, the parties agree not to contest the validity or enforceability of telephonic recordings entered into in accordance with the requirements of this Base Contract.

SECTION 2. DEFINITIONS

2.1. The terms set forth below shall have the meaning ascribed to them below. Other terms are also defined elsewhere in the Contract and shall have the meanings ascribed to them herein.

2.2. “Additional Event of Default” shall mean Transactional Cross Default or Indebtedness Cross Default, each as and if selected by the parties pursuant to the Base Contract.

2.3. “Affiliate” shall mean, in relation to any person, any entity controlled, directly or indirectly, by the person, any entity that controls, directly or indirectly, the person or any entity directly or indirectly under common control with the person. For this purpose, “control” of any entity or person means ownership of at least 50 percent of the voting power of the entity or person.

2.4. “Alternative Damages” shall mean such damages, expressed in dollars or dollars per MMBtu, as the parties shall agree upon in the Transaction Confirmation, in the event either Seller or Buyer fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer.

2.5. "Base Contract" shall mean a contract executed by the parties that incorporates these General Terms and Conditions by reference; that specifies the agreed selections of provisions contained herein; and that sets forth other information required herein and any Special Provisions and addendum(s) as identified on page one.

2.6. "British thermal unit" or "Btu" shall mean the International BTU, which is also called the Btu (IT).

2.7. "Business Day(s)" shall mean Monday through Friday, excluding Federal Banking Holidays for transactions in the U.S.

2.8. "Confirm Deadline" shall mean 5:00 p.m. in the receiving party's time zone on the second Business Day following the Day a Transaction Confirmation is received or, if applicable, on the Business Day agreed to by the parties in the Base Contract; provided, if the Transaction Confirmation is time stamped after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next Business Day.

2.9. "Confirming Party" shall mean the party designated in the Base Contract to prepare and forward Transaction Confirmations to the other party.

2.10. "Contract" shall mean the legally-binding relationship established by (i) the Base Contract, (ii) any and all binding Transaction Confirmations and (iii) where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, any and all transactions that the parties have entered into through an EDI transmission or by telephone, but that have not been confirmed in a binding Transaction Confirmation, all of which shall form a single integrated agreement between the parties.

2.11. "Contract Price" shall mean the amount expressed in U.S. Dollars per MMBtu to be paid by Buyer to Seller for the purchase of Gas as agreed to by the parties in a transaction.

2.12. "Contract Quantity" shall mean the quantity of Gas to be delivered and taken as agreed to by the parties in a transaction.

2.13. "Cover Standard", as referred to in Section 3.2, shall mean that if there is an unexcused failure to take or deliver any quantity of Gas pursuant to this Contract, then the performing party shall use commercially reasonable efforts to (i) if Buyer is the performing party, obtain Gas, (or an alternate fuel if elected by Buyer and replacement Gas is not available), or (ii) if Seller is the performing party, sell Gas, in either case, at a price reasonable for the delivery or production area, as applicable, consistent with: the amount of notice provided by the nonperforming party; the immediacy of the Buyer's Gas consumption needs or Seller's Gas sales requirements, as applicable; the quantities involved; and the anticipated length of failure by the nonperforming party.

2.14. "Credit Support Obligation(s)” shall mean any obligation(s) to provide or establish credit support for, or on behalf of, a party to this Contract such as cash, an irrevocable standby letter of credit, a margin agreement, a prepayment, a security interest in an asset, guaranty, or other good and sufficient security of a continuing nature.

2.15. "Day" shall mean a period of 24 consecutive hours, coextensive with a "day" as defined by the Receiving Transporter in a particular transaction.

2.16. "Delivery Period" shall be the period during which deliveries are to be made as agreed to by the parties in a transaction.

2.17. "Delivery Point(s)" shall mean such point(s) as are agreed to by the parties in a transaction.

2.18. "EDI" shall mean an electronic data interchange pursuant to an agreement entered into by the parties, specifically relating to the communication of Transaction Confirmations under this Contract.

2.19. "EFP" shall mean the purchase, sale or exchange of natural Gas as the "physical" side of an exchange for physical transaction involving gas futures contracts. EFP shall incorporate the meaning and remedies of "Firm", provided that a party’s excuse for nonperformance of its obligations to deliver or receive Gas will be governed by the rules of the relevant futures exchange regulated under the Commodity Exchange Act.

2.20. "Firm" shall mean that either party may interrupt its performance without liability only to the extent that such performance is prevented for reasons of Force Majeure; provided, however, that during Force Majeure interruptions, the party invoking Force Majeure may be responsible for any Imbalance Charges as set forth in Section

4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by the Transporter.

2.21. "Gas" shall mean any mixture of hydrocarbons and noncombustible gases in a gaseous state consisting primarily of methane.

2.22. "Guarantor" shall mean any entity that has provided a guaranty of the obligations of a party hereunder.

2.23. "Imbalance Charges" shall mean any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter's balance and/or nomination requirements.

2.24. "Indebtedness Cross Default" shall mean if selected on the Base Contract by the parties with respect to a party, that it or its Guarantor, if any, experiences a default, or similar condition or event however therein defined, under one or more agreements or instruments, individually or collectively, relating to indebtedness (such indebtedness to include any obligation whether present or future, contingent or otherwise, as principal or surety or otherwise) for the payment or repayment of borrowed money in an aggregate amount greater than the threshold specified in the Base Contract with respect to such party or its Guarantor, if any, which results in such indebtedness becoming immediately due and payable.

2.25. "Interruptible" shall mean that either party may interrupt its performance at any time for any reason, whether or not caused by an event of Force Majeure, with no liability, except such interrupting party may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by Transporter.

2.26. "MMBtu" shall mean one million British thermal units, which is equivalent to one dekatherm.

2.27. "Month" shall mean the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.

2.28. "Payment Date" shall mean a date, as indicated on the Base Contract, on or before which payment is due Seller for Gas received by Buyer in the previous Month.

2.29. "Receiving Transporter" shall mean the Transporter receiving Gas at a Delivery Point, or absent such receiving Transporter, the Transporter delivering Gas at a Delivery Point.

2.30. "Scheduled Gas" shall mean the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.

2.31. "Specified Transaction(s)" shall mean any other transaction or agreement between the parties for the purchase, sale or exchange of physical Gas, and any other transaction or agreement identified as a Specified Transaction under the Base Contract.

2.32. "Spot Price " as referred to in Section 3.2 shall mean the price listed in the publication indicated on the Base Contract, under the listing applicable to the geographic location closest in proximity to the Delivery Point(s) for the relevant Day; provided, if there is no single price published for such location for such Day, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is published for such Day, then the Spot Price shall be the average of the following: (i) the price (determined as stated above) for the first Day for which a price or range of prices is published that next precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day.

2.33. "Transaction Confirmation" shall mean a document, similar to the form of Exhibit A, setting forth the terms of a transaction formed pursuant to Section 1 for a particular Delivery Period.

2.34. "Transactional Cross Default" shall mean if selected on the Base Contract by the parties with respect to a party, that it shall be in default, however therein defined, under any Specified Transaction.

2.35. "Termination Option" shall mean the option of either party to terminate a transaction in the event that the other party fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer for a designated number of days during a period as specified on the applicable Transaction Confirmation.

2.36. "Transporter(s)" shall mean all Gas gathering or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting Gas for Seller or Buyer upstream or downstream, respectively, of the Delivery Point pursuant to a particular transaction.

SECTION 3. PERFORMANCE OBLIGATION

3.1. Seller agrees to sell and deliver, and Buyer agrees to receive and purchase, the Contract Quantity for a particular transaction in accordance with the terms of the Contract. Sales and purchases will be on a Firm or Interruptible basis, as agreed to by the parties in a transaction.

The parties have selected either the "Cover Standard" or the "Spot Price Standard" as indicated on the Base

Contract.

Cover Standard:

3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s) excluding any quantity for which no replacement is available; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in the amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s) excluding any quantity for which no sale is available; and (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available for all or any portion of the Contract Quantity of Gas, then in addition to (i) or (ii) above, as applicable, the sole and exclusive remedy of the performing party with respect to the Gas not replaced or sold shall be an amount equal to any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the quantity of such Gas not replaced or sold. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

Spot Price Standard:

3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

3.3. Notwithstanding Section 3.2, the parties may agree to Alternative Damages in a Transaction Confirmation executed in writing by both parties.

3.4. In addition to Sections 3.2 and 3.3, the parties may provide for a Termination Option in a Transaction Confirmation executed in writing by both parties. The Transaction Confirmation containing the Termination Option will designate the length of nonperformance triggering the Termination Option and the procedures for exercise thereof, how damages for nonperformance will be compensated, and how liquidation costs will be calculated.

SECTION 4. TRANSPORTATION, NOMINATIONS, AND IMBALANCES

4.1. Seller shall have the sole responsibility for transporting the Gas to the Delivery Point(s). Buyer shall have the sole responsibility for transporting the Gas from the Delivery Point(s).

4.2. The parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior Notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

4.3. The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's receipt of quantities of Gas greater than or less than the Scheduled Gas, then Buyer shall pay for such Imbalance Charges or reimburse Seller for such Imbalance Charges paid by Seller. If the Imbalance Charges were incurred as a result of Seller's delivery of quantities of Gas greater than or less than the Scheduled Gas, then Seller shall pay for such Imbalance Charges or reimburse Buyer for such Imbalance Charges paid by Buyer.

SECTION 5. QUALITY AND MEASUREMENT

All Gas delivered by Seller shall meet the pressure, quality and heat content requirements of the Receiving Transporter. The unit of quantity measurement for purposes of this Contract shall be one MMBtu dry. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

SECTION 6. TAXES

The parties have selected either "Buyer Pays At and After Delivery Point" or "Seller Pays Before and At Delivery Point" as indicated on the Base Contract.

Buyer Pays At and After Delivery Point:

Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas at the Delivery Point(s) and all Taxes after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

Seller Pays Before and At Delivery Point:

Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s) and all Taxes at the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

SECTION 7. BILLING, PAYMENT, AND AUDIT

7.1. Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges, providing supporting documentation acceptable in industry practice to support the amount charged. If the actual quantity delivered is not known by the billing date, billing will be prepared based on the quantity of Scheduled Gas. The invoiced quantity will then be adjusted to the actual quantity on the following Month's billing or as soon thereafter as actual delivery information is available.

7.2. Buyer shall remit the amount due under Section 7.1 in the manner specified in the Base Contract, in immediately available funds, on or before the later of the Payment Date or 10 Days after receipt of the invoice by Buyer; provided that if the Payment Date is not a Business Day, payment is due on the next Business Day following that date. In the event any payments are due Buyer hereunder, payment to Buyer shall be made in accordance with this Section 7.2.

7.3. In the event payments become due pursuant to Sections 3.2 or 3.3, the performing party may submit an invoice to the nonperforming party for an accelerated payment setting forth the basis upon which the invoiced amount was calculated. Payment from the nonperforming party will be due five Business Days after receipt of invoice.

7.4. If the invoiced party, in good faith, disputes the amount of any such invoice or any part thereof, such invoiced party will pay such amount as it concedes to be correct; provided, however, if the invoiced party disputes the amount due, it must provide supporting documentation acceptable in industry practice to support the amount paid or disputed without undue delay. In the event the parties are unable to resolve such dispute, either party may pursue any remedy available at law or in equity to enforce its rights pursuant to this Section.

7.5. If the invoiced party fails to remit the full amount payable when due, interest on the unpaid portion shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

7.6. A party shall have the right, at its own expense, upon reasonable Notice and at reasonable times, to examine and audit and to obtain copies of the relevant portion of the books, records, and telephone recordings of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, or computation made under the Contract. This right to examine, audit, and to obtain copies shall not be available with respect to proprietary information not directly relevant to transactions under this Contract. All invoices and billings shall be conclusively presumed final and accurate and all associated claims for under- or overpayments shall be deemed waived unless such invoices or billings are objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments under Section 7 shall be paid in full by the party owing payment within 30 Days of Notice and substantiation of such inaccuracy.

7.7. Unless the parties have elected on the Base Contract not to make this Section 7.7 applicable to this Contract, the parties shall net all undisputed amounts due and owing, and/or past due, arising under the Contract such that the party owing the greater amount shall make a single payment of the net amount to the other party in accordance with

Section 7; provided that no payment required to be made pursuant to the terms of any Credit Support Obligation or pursuant to Section 7.3 shall be subject to netting under this Section. If the parties have executed a separate netting agreement, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 8. TITLE, WARRANTY, AND INDEMNITY

8.1. Unless otherwise specifically agreed, title to the Gas shall pass from Seller to Buyer at the Delivery Point(s). Seller shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Delivery Point(s). Buyer shall have responsibility for and assume any liability with respect to said Gas after its delivery to Buyer at the Delivery Point(s).

8.2. Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims. EXCEPT AS PROVIDED IN THIS SECTION 8.2 AND IN SECTION 15.8, ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

8.3. Seller agrees to indemnify Buyer and save it harmless from all losses, liabilities or claims including reasonable attorneys' fees and costs of court ("Claims"), from any and all persons, arising from or out of claims of title, personal injury (including death) or property damage from said Gas or other charges thereon which attach before title passes to Buyer. Buyer agrees to indemnify Seller and save it harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury (including death) or property damage from said Gas or other charges thereon which attach after title passes to Buyer.

8.4. The parties agree that the delivery of and the transfer of title to all Gas under this Contract shall take place within the Customs Territory of the United States (as defined in general note 2 of the Harmonized Tariff Schedule of the United States 19 U.S.C. §1202, General Notes, page 3); provided, however, that in the event Seller took title to the Gas outside the Customs Territory of the United States, Seller represents and warrants that it is the importer of record for all Gas entered and delivered into the United States, and shall be responsible for entry and entry summary filings as well as the payment of duties, taxes and fees, if any, and all applicable record keeping requirements.

8.5. Notwithstanding the other provisions of this Section 8, as between Seller and Buyer, Seller will be liable for all Claims to the extent that such arise from the failure of Gas delivered by Seller to meet the quality requirements of Section 5.

SECTION 9. NOTICES

9.1. All Transaction Confirmations, invoices, payment instructions, and other communications made pursuant to the Base Contract ("Notices") shall be made to the addresses specified in writing by the respective parties from time to time.

9.2. All Notices required hereunder shall be in writing and may be sent by facsimile or mutually acceptable electronic means, a nationally recognized overnight courier service, first class mail or hand delivered.

9.3. Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions will apply. Notices sent by facsimile shall be deemed to have been received upon the sending party's receipt of its facsimile machine's confirmation of successful transmission. If the day on which such facsimile is received is not a Business Day or is after five p.m. on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day. Notice by overnight mail or courier shall be deemed to have been received on the next Business Day after it was sent or such earlier time as is confirmed by the receiving party. Notice via first class mail shall be considered delivered five Business Days after mailing.

9.4. The party receiving a commercially acceptable Notice of change in payment instructions or other payment information shall not be obligated to implement such change until ten Business Days after receipt of such Notice.

SECTION 10. FINANCIAL RESPONSIBILITY

10.1. If either party (“X”) has reasonable grounds for insecurity regarding the performance of any obligation under this Contract (whether or not then due) by the other party (“Y”) (including, without limitation, the occurrence of a material change in the creditworthiness of Y or its Guarantor, if applicable), X may demand Adequate Assurance of Performance. “Adequate Assurance of Performance” shall mean sufficient security in the form, amount, for a term, and from an issuer, all as reasonably acceptable to X, including, but not limited to cash, a standby irrevocable letter of credit, a prepayment, a security interest in an asset or guaranty. Y hereby grants to X a continuing first priority security interest in, lien on, and right of setoff against all Adequate Assurance of Performance in the form of cash transferred by Y to X pursuant to this Section 10.1. Upon the return by X to Y of such Adequate Assurance of Performance, the security interest and lien granted hereunder on that Adequate Assurance of Performance shall be released automatically and, to the extent possible, without any further action by either party.

10.2. In the event (each an "Event of Default") either party (the "Defaulting Party") or its Guarantor shall: (i) make an assignment or any general arrangement for the benefit of creditors; (ii) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a proceeding or case under any bankruptcy or similar law for the protection of creditors or have such petition filed or proceeding commenced against it; (iii) otherwise become bankrupt or insolvent (however evidenced); (iv) be unable to pay its debts as they fall due; (v) have a receiver, provisional liquidator, conservator, custodian, trustee or other similar official appointed with respect to it or substantially all of its assets; (vi) fail to perform any obligation to the other party with respect to any Credit Support Obligations relating to the Contract; (vii) fail to give Adequate Assurance of Performance under Section 10.1 within 48 hours but at least one Business Day of a written request by the other party; (viii) not have paid any amount due the other party hereunder on or before the second Business Day following written Notice that such payment is due; or ix) be the affected party with respect to any Additional Event of Default; then the other party (the "Non-Defaulting Party") shall have the right, at its sole election, to immediately withhold and/or suspend deliveries or payments upon Notice and/or to terminate and liquidate the transactions under the Contract, in the manner provided in Section 10.3, in addition to any and all other remedies available hereunder.

10.3. If an Event of Default has occurred and is continuing, the Non-Defaulting Party shall have the right, by Notice to the Defaulting Party, to designate a Day, no earlier than the Day such Notice is given and no later than 20 Days after such Notice is given, as an early termination date (the "Early Termination Date") for the liquidation and termination pursuant to Section 10.3.1 of all transactions under the Contract, each a "Terminated Transaction". On the Early Termination Date, all transactions will terminate, other than those transactions, if any, that may not be liquidated and terminated under applicable law ("Excluded Transactions"), which Excluded Transactions must be liquidated and terminated as soon thereafter as is legally permissible, and upon termination shall be a Terminated Transaction and be valued consistent with Section 10.3.1 below. With respect to each Excluded Transaction, its actual termination date shall be the Early Termination Date for purposes of Section 10.3.1.

The parties have selected either "Early Termination Damages Apply" or "Early Termination Damages Do Not Apply" as indicated on the Base Contract.

Early Termination Damages Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, (i) the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract and (ii) the Market Value, as defined below, of each Terminated Transaction. The Non-Defaulting Party shall (x) liquidate and accelerate each Terminated Transaction at its Market Value, so that each amount equal to the difference between such Market Value and the Contract Value, as defined below, of such Terminated Transaction(s) shall be due to the Buyer under the Terminated Transaction(s) if such Market Value exceeds the Contract Value and to the Seller if the opposite is the case; and (y) where appropriate, discount each amount then due under clause (x) above to present value in a commercially reasonable manner as of the Early Termination Date (to take account of the period between the date of liquidation and the date on which such amount would have otherwise been due pursuant to the relevant Terminated Transactions).

For purposes of this Section 10.3.1, "Contract Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the Contract Price, and "Market Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the market price for a similar transaction at the Delivery Point determined by the Non-Defaulting Party in a commercially reasonable manner. To ascertain the Market Value, the Non-Defaulting Party may consider, among other valuations, any or all of the settlement prices of NYMEX Gas futures contracts, quotations from leading dealers in energy swap contracts or physical gas trading markets, similar sales or purchases and any other bona fide third-party offers, all adjusted for the length of the term and differences in transportation costs. A party shall not be required to enter into a replacement transaction(s) in order to determine the Market Value. Any extension(s) of the term of a transaction to which parties are not bound as of the Early Termination Date (including but not limited to "evergreen provisions") shall not be considered in determining Contract Values and Market Values. For the avoidance of doubt, any option pursuant to which one party has the right to extend the term of a transaction shall be considered in determining Contract Values and Market Values. The rate of interest used in calculating net present value shall be determined by the Non-Defaulting Party in a commercially reasonable manner.

Early Termination Damages Do Not Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes

such payment under this Contract.

The parties have selected either "Other Agreement Setoffs Apply" or "Other Agreement Setoffs Do Not Apply" as indicated on the Base Contract.

Other Agreement Setoffs Apply:

Bilateral Setoff Option:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party is hereby authorized to setoff any Net Settlement Amount against (i) any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract; and (ii) any amount(s) (including any excess cash margin or excess cash collateral) owed or held by the party that is entitled to the Net Settlement Amount under any other agreement or arrangement between the parties.

Triangular Setoff Option:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option, and without prior Notice to the Defaulting Party, the Non-Defaulting Party is hereby authorized to setoff (i) any Net Settlement Amount against any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract; (ii) any Net Settlement Amount against any amount(s) (including any excess cash margin or excess cash collateral) owed by or to a party under any other agreement or arrangement between the parties; (iii) any Net Settlement Amount owed to the Non-Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Non-Defaulting Party or its Affiliates to the Defaulting Party under any other agreement or arrangement; (iv) any Net Settlement Amount owed to the Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Defaulting Party to the Non-Defaulting Party or its Affiliates under any other agreement or arrangement; and/or (v) any Net Settlement Amount owed to the Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Defaulting Party or its Affiliates to the Non-Defaulting Party under any other agreement or arrangement.

Other Agreement Setoffs Do Not Apply:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party may setoff any Net Settlement Amount against any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract.

10.3.3. If any obligation that is to be included in any netting, aggregation or setoff pursuant to Section 10.3.2 is unascertained, the Non-Defaulting Party may in good faith estimate that obligation and net, aggregate or setoff, as applicable, in respect of the estimate, subject to the Non-Defaulting Party accounting to the Defaulting Party when the obligation is ascertained. Any amount not then due which is included in any netting, aggregation or setoff pursuant to Section 10.3.2 shall be discounted to net present value in a commercially reasonable manner determined by the Non-Defaulting Party.

10.4. As soon as practicable after a liquidation, Notice shall be given by the Non-Defaulting Party to the Defaulting Party of the Net Settlement Amount, and whether the Net Settlement Amount is due to or due from the Non-Defaulting Party. The Notice shall include a written statement explaining in reasonable detail the calculation of the Net Settlement Amount, provided that failure to give such Notice shall not affect the validity or enforceability of the liquidation or give rise to any claim by the Defaulting Party against the Non-Defaulting Party. The Net Settlement Amount as well as any setoffs applied against such amount pursuant to Section 10.3.2, shall be paid by the close of business on the second Business Day following such Notice, which date shall not be earlier than the Early Termination Date. Interest on any unpaid portion of the Net Settlement Amount as adjusted by setoffs, shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

10.5. The parties agree that the transactions hereunder constitute a "forward contract" within the meaning of the United States Bankruptcy Code and that Buyer and Seller are each "forward contract merchants" within the meaning of the United States Bankruptcy Code.

10.6. The Non-Defaulting Party's remedies under this Section 10 are the sole and exclusive remedies of the Non-Defaulting Party with respect to the occurrence of any Early Termination Date. Each party reserves to itself all other rights, setoffs, counterclaims and other defenses that it is or may be entitled to arising from the Contract.

10.7. With respect to this Section 10, if the parties have executed a separate netting agreement with close-out netting provisions, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 11. FORCE MAJEURE

11.1. Except with regard to a party's obligation to make payment(s) due under Section 7, Section 10.4, and Imbalance Charges under Section 4, neither party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by Force Majeure. The term "Force Majeure" as employed herein means any cause not reasonably within the control of the party claiming suspension, as further defined in Section 11.2.

11.2. Force Majeure shall include, but not be limited to, the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption and/or curtailment of Firm transportation and/or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars, or acts of terror; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.

11.3. Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary Firm transportation unless primary, in-path, Firm transportation is also curtailed; (ii) the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (iii) economic hardship, to include, without limitation, Seller's ability to sell Gas at a higher or more advantageous price than the Contract Price, Buyer's ability to purchase Gas at a lower or more advantageous price than the Contract Price, or a regulatory agency disallowing, in whole or in part, the pass through of costs resulting from this Contract; (iv) the loss of Buyer's market(s) or Buyer's inability to use or resell Gas purchased hereunder, except, in either case, as provided in Section 11.2; or (v) the loss or failure of Seller's gas supply or depletion of reserves, except, in either case, as provided in Section 11.2. The party claiming Force Majeure shall not be excused from its responsibility for Imbalance Charges.

11.4. Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be within the sole discretion of the party experiencing such disturbance.

11.5. The party whose performance is prevented by Force Majeure must provide Notice to the other party. Initial Notice may be given orally; however, written Notice with reasonably full particulars of the event or occurrence is required as soon as reasonably possible. Upon providing written Notice of Force Majeure to the other party, the affected party will be relieved of its obligation, from the onset of the Force Majeure event, to make or accept delivery of Gas, as applicable, to the extent and for the duration of Force Majeure, and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.

11.6. Notwithstanding Sections 11.2 and 11.3, the parties may agree to alternative Force Majeure provisions in a Transaction Confirmation executed in writing by both parties.

SECTION 12. TERM

This Contract may be terminated on 30 Day's written Notice, but shall remain in effect until the expiration of the latest Delivery Period of any transaction(s). The rights of either party pursuant to Section 7.6, Section 10, Section 13, the obligations to make payment hereunder, and the obligation of either party to indemnify the other, pursuant hereto shall survive the termination of the Base Contract or any transaction.

SECTION 13. LIMITATIONS

FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY. A PARTY'S LIABILITY HEREUNDER SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, A PARTY'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY. SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH

NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

SECTION 14. MARKET DISRUPTION

If a Market Disruption Event has occurred then the parties shall negotiate in good faith to agree on a replacement price for the Floating Price (or on a method for determining a replacement price for the Floating Price) for the affected Day, and if the parties have not so agreed on or before the second Business Day following the affected Day then the replacement price for the Floating Price shall be determined within the next two following Business Days with each party obtaining, in good faith and from non-affiliated market participants in the relevant market, two quotes for prices of Gas for the affected Day of a similar quality and quantity in the geographical location closest in proximity to the Delivery Point and averaging the four quotes. If either party fails to provide two quotes then the average of the other party's two quotes shall determine the replacement price for the Floating Price. "Floating Price" means the price or a factor of the price agreed to in the transaction as being based upon a specified index. "Market Disruption Event" means, with respect to an index specified for a transaction, any of the following events: (a) the failure of the index to announce or publish information necessary for determining the Floating Price; (b) the failure of trading to commence or the permanent discontinuation or material suspension of trading on the exchange or market acting as the index; (c) the temporary or permanent discontinuance or unavailability of the index; (d) the temporary or permanent closing of any exchange acting as the index; or (e) both parties agree that a material change in the formula for or the method of determining the Floating Price has occurred. For the purposes of the calculation of a replacement price for the Floating Price, all numbers shall be rounded to three decimal places. If the fourth decimal number is five or greater, then the third decimal number shall be increased by one and if the fourth decimal number is less than five, then the third decimal number shall remain unchanged.

SECTION 15. MISCELLANEOUS

15.1. This Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, rights and obligations of this Contract shall run for the full term of this Contract. No assignment of this Contract, in whole or in part, will be made without the prior written consent of the non-assigning party (and shall not relieve the assigning party from liability hereunder), which consent will not be unreasonably withheld or delayed; provided, either party may (i) transfer, sell, pledge, encumber, or assign this Contract or the accounts, revenues, or proceeds hereof in connection with any financing or other financial arrangements, or (ii) transfer its interest to any parent or Affiliate by assignment, merger or otherwise without the prior approval of the other party. Upon any such assignment, transfer and assumption, the transferor shall remain principally liable for and shall not be relieved of or discharged from any obligations hereunder.

15.2. If any provision in this Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Contract.

15.3. No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach.

15.4. This Contract sets forth all understandings between the parties respecting each transaction subject hereto, and any prior contracts, understandings and representations, whether oral or written, relating to such transactions are merged into and superseded by this Contract and any effective transaction(s). This Contract may be amended only by a writing executed by both parties.

15.5. The interpretation and performance of this Contract shall be governed by the laws of the jurisdiction as indicated on the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction.

15.6. This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any governmental authority having jurisdiction over the parties, their facilities, or Gas supply, this Contract or transaction or any provisions thereof.

15.7. There is no third party beneficiary to this Contract.

15.8. Each party to this Contract represents and warrants that it has full and complete authority to enter into and perform this Contract. Each person who executes this Contract on behalf of either party represents and warrants that it has full and complete authority to do so and that such party will be bound thereby.

15.9. The headings and subheadings contained in this Contract are used solely for convenience and do not constitute a part of this Contract between the parties and shall not be used to construe or interpret the provisions of this Contract.

15.10. Unless the parties have elected on the Base Contract not to make this Section 15.10 applicable to this Contract, neither party shall disclose directly or indirectly without the prior written consent of the other party the terms of any

transaction to a third party (other than the employees, lenders, royalty owners, counsel, accountants and other agents of the party, or prospective purchasers of all or substantially all of a party's assets or of any rights under this Contract, provided such persons shall have agreed to keep such terms confidential) except (i) in order to comply with any applicable law, order, regulation, or exchange rule, (ii) to the extent necessary for the enforcement of this Contract , (iii) to the extent necessary to implement any transaction, (iv) to the extent necessary to comply with a regulatory agency's reporting requirements including but not limited to gas cost recovery proceedings; or (v) to the extent such information is delivered to such third party for the sole purpose of calculating a published index. Each party shall notify the other party of any proceeding of which it is aware which may result in disclosure of the terms of any transaction (other than as permitted hereunder) and use reasonable efforts to prevent or limit the disclosure. The existence of this Contract is not subject to this confidentiality obligation. Subject to Section 13, the parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with this confidentiality obligation. The terms of any transaction hereunder shall be kept confidential by the parties hereto for one year from the expiration of the transaction.

In the event that disclosure is required by a governmental body or applicable law, the party subject to such requirement may disclose the material terms of this Contract to the extent so required, but shall promptly notify the other party, prior to disclosure, and shall cooperate (consistent with the disclosing party's legal obligations) with the other party's efforts to obtain protective orders or similar restraints with respect to such disclosure at the expense of the other party.

15.11. The parties may agree to dispute resolution procedures in Special Provisions attached to the Base Contract or in a Transaction Confirmation executed in writing by both parties

15.12. Any original executed Base Contract, Transaction Confirmation or other related document may be digitally copied, photocopied, or stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence–on paper, the Transaction Confirmation, if introduced as evidence in automated facsimile form, the recording, if introduced as evidence in its original form, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings will be admissible as between the parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the recording, the Transaction Confirmation, or the Imaged Agreement on the basis that such were not originated or maintained in documentary form. However, nothing herein shall be construed as a waiver of any other objection to the admissibility of such evidence.

DISCLAIMER: The purposes of this Contract are to facilitate trade, avoid misunderstandings and make more definite the terms of contracts of purchase and sale of natural gas. Further, NAESB does not mandate the use of this Contract by any party. **NAESB DISCLAIMS AND EXCLUDES, AND ANY USER OF THIS CONTRACT ACKNOWLEDGES AND AGREES TO NAESB'S DISCLAIMER OF, ANY AND ALL WARRANTIES, CONDITIONS OR REPRESENTATIONS, EXPRESS OR IMPLIED, ORAL OR WRITTEN, WITH RESPECT TO THIS CONTRACT OR ANY PART THEREOF, INCLUDING ANY AND ALL IMPLIED WARRANTIES OR CONDITIONS OF TITLE, NON-INFRINGEMENT, MERCHANTABILITY, OR FITNESS OR SUITABILITY FOR ANY PARTICULAR PURPOSE (WHETHER OR NOT NAESB KNOWS, HAS REASON TO KNOW, HAS BEEN ADVISED, OR IS OTHERWISE IN FACT AWARE OF ANY SUCH PURPOSE), WHETHER ALLEGED TO ARISE BY LAW, BY REASON OF CUSTOM OR USAGE IN THE TRADE, OR BY COURSE OF DEALING. EACH USER OF THIS CONTRACT ALSO AGREES THAT UNDER NO CIRCUMSTANCES WILL NAESB BE LIABLE FOR ANY DIRECT, SPECIAL, INCIDENTAL, EXEMPLARY, PUNITIVE OR CONSEQUENTIAL DAMAGES ARISING OUT OF ANY USE OF THIS CONTRACT.**

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

EXHIBIT A

Letterhead/Logo	Date: _____, _____ Transaction Confirmation #: _____

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated _____. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt unless otherwise specified in the Base Contract.

SELLER:	**BUYER:**
Attn: Phone: Fax: Base Contract No. _____ Transporter: Transporter Contract Number: _____	Attn: Phone: Fax: Base Contract No. _____ Transporter: _____ Transporter Contract Number: _____

Contract Price: $_____/MMBtu or _____

Delivery Period: Begin: _____ End: _____

Performance Obligation and Contract Quantity: (Select One)

Firm (Fixed Quantity):	**Firm (Variable Quantity):**	**Interruptible:**
_____ MMBtus/day ☐EFP	_____ MMBtus/day Minimum _____ MMBtus/day Maximum subject to Section 4.2. at election of ☐Buyer or ☐ Seller	Up to _____ MMBtus/day

Primary Delivery Point(s): _____

Special Conditions:

1.)Seller must utilize pipeline contracts with primary firm capacity to the Primary Delivery Point.

Seller: _____	Buyer: _____
By: _____	By: _____
Title: _____	Title: _____
Date: _____	Date: _____

Special Provisions to Base Contract

_____and _____, hereby agree, effective as of (“Effective Date”), to the following special provisions (“Special Provisions”), which hereby modify and amend the North American Energy Standards Board, Inc. (“NAESB”) Base Contract for Sale and Purchase of Natural Gas, with the Effective Date _____(“Base Contract”). Unless specifically agreed to otherwise in a Transaction Confirmation by the parties, the Base Contract, as modified by these Special Provisions, shall apply to all transactions for the purchase and sale of Gas between the parties. All capitalized terms used herein and not otherwise defined shall have the meaning set forth in the Base Contract.

1) Section 3.4 is amended by adding the following:

   A performing party shall have the option to terminate an Affected Transaction by providing written notice to the non-performing party designating an Early Termination Date on which the Affected Transaction shall terminate. An "Affected Transaction" means a Firm Transaction with a Delivery Period of at least 30 Days in respect of which there has occurred either three consecutive Failure Days or five total Failure Days during the Term of such Firm Transaction. A "Failure Day" means a Day on which the non-performing party has failed to purchase and receive, or sell and deliver, as applicable, an amount equal to or greater than 96% of the Contract Quantity to be purchased and received or sold and delivered on such Day, which failure is not excused because of the non-performance of the performing party or by Force Majeure.

2) Section 5 shall be deleted in its entirety and replaced with following:

   All Gas delivered by Seller shall meet the pressure, quality, heat content and interchangeability standards provided in the effective tariff at the time of delivery of the respective Receiving Transporter. The unit of quantity measurement for purposes of this Contract shall be one MMBtu dry. Measurement of Gas quantities hereunder shall be in accordance with the established procedures provided in the effective tariff at the time of delivery of the Receiving Transporter.

3) This section shall be added as new 11.7.

   Notwithstanding anything to the contrary in Section 11, Force Majeure shall not include any act, event or circumstances occurring in a country in which LNG is produced or procured or any event that affects an LNG vessel prior to such vessel's departure from the LNG Loading Facilities (including but not limited to Gas liquefaction trains and associated liquefaction facilities, LNG storage and loading facilities, berth and marine facilities and other facilities, at which LNG is loaded onto LNG vessels) or during its voyage to the regasification or storage terminal for eventual delivery to selected delivery points.

Schedule TJB/JEA-4
Proposed Electric Reliability

Electric Reliability Service Program

January 15, 2016

I. Purpose:

The purpose of the Electric Reliability Service Program ("ERSP") is to remedy an electric-reliability concern in the natural gas-fired and dual-fuel generation market by acquiring natural gas pipeline and storage capacity specifically designed to serve these plants under all operating conditions. The ERSP has the objective of increasing available gas supply for generation; thereby suppressing price volatility in electricity markets associated with natural gas fuel constraints. The ERSP is designed to provide electric generators with access to pipeline capacity and supply, specifically dedicated with firm, primary delivery rights to the respective generation-facility meters. Natural gas-fired electric generators do not currently maintain this type of capacity rights for fuel requirements. The ERSP will be directed by an Electric Distribution Company (EDC) Gas Asset Executive Committee ("EDC-EC"), administered by a Capacity Manager. The EDCs are subject to state public utility commission jurisdiction and the ERSP is subject to the approval of the respective regulatory authority.

II. Roles and Operating Parameters:

(1) Electric Distribution Company

a. Natural Gas Infrastructure Acquisition:

i. The EDCs will acquire natural gas infrastructure in the form of pipeline capacity, storage assets or supply that enables the reliable delivery of natural gas to gas-fired power generators in the ISO New England ("ISO-NE") control area on a primary firm basis. The EDCs will enlist a Capacity Manager to administer the release of capacity and/or gas supply to electric generators and to the general market, if not acquired by the generators.

b. Governance of Program

i. The EDC Gas Asset Executive Committee, or EDC-EC, will be comprised of representatives of each participating EDC. The EDC-EC will define and oversee the role of the Capacity Manager in accordance with the state-approved program requirements. The EDC-EC also has the authority to review and approve the Policy and Procedures referenced below. The EDC-EC is the arbitrator for any disputes between the EDC Gas Asset Working Committee (EDC-WC) and the Capacity Manager.

ii. The EDC-WC will be comprised of a minimum of one representative from each EDC and will create and establish the Policy and Procedures for the Capacity Manager. The Policy and Procedures will be approved by the EDC-EC. The EDC-WC will meet as needed to address any issues associated with the gas assets and the Capacity Manager. The EDC-WC will interact and guide the actions of the Capacity Manager including the establishment of the Policies and Procedures, consistent with the state-approved program requirements.

iii. Reporting and Coordinating with the State Regulatory Commission (Quarterly). The EDC-EC will file a cost allocation and status report with the respective State Regulatory Commission within 60 days of the close of each quarter following the commencement of capacity release transactions under the Program.

Electric Reliability Service Program

January 15, 2016

iv. The EDC-EC will monitor the program activity and recommend changes as needed to adjust the parameters should regulatory requirements or operating or market conditions require.

(2) Capacity Manager

a. The Capacity Manager role is administrative and operational where the manager will handle the full range of capacity-release transactions and would release capacity to electric generators and the general market, as permitted under the Policy and Procedures.

b. The Capacity Manager would release capacity as directed by EDC-WC, according to results of request for proposals from "generator pools" for capacity.

c. The Capacity Manager would sell liquefied natural gas ("LNG") and day-ahead capacity as needed to generator pools.

(3) Program Parameters and Release Structure

a. The ERSP will make available to eligible capacity-release participants, which are classified as all gas-fired generators with interconnected meters (directly/indirectly) to the corresponding pipeline located in the ISO-NE control area.

b. The release schedule will coincide with ISO-NE Forward Capacity Market ("FCM") bidding windows such that generators can acquire fuel capacity prior to commitments in the FCM. The actual dates will be set once ISO-NE releases its annual schedule for the corresponding year. The remainder of the capacity will be made available in bidding windows corresponding to the traditional natural gas trading periods.

c. Release Schedule Outline (See figure 1 for more detail)

i. 1 Year Release (FCM1)- 3 years prior to the calendar year

ii. 1 Year Release (FCM2) - 2 years prior to the calendar year

iii. 1 Year Release - 1 year prior to the calendar year

iv. Seasonal Release - Prior to the start of each period

v. 1 Monthly Release (FCM) - 2 month prior to the month of flow

vi. 1 Monthly Release - 1 month prior to the month of flow

vii. Daily (Weekend/Holiday) - 2 days prior to the day of flow

*To achieve the intended objectives of the ERSP, the release schedule outline and parameters are subject to change as the EDC-WC evaluates impacts and program effectiveness over time.

d. In each of the scheduled releases listed above, all capacity paths will be made available in percentages equal to the ratio of the specific path to the total capacity being released.

Electric Reliability Service Program

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(4) Capacity Release and LNG Sales

a. The Capacity Manager may release the EDC capacity to various electric generators, as the directed by the EDC-WC. The "Capacity Release" is the release of the EDCs' contracted interstate pipeline capacity by the Capacity Manager directly to New England gas-fired electric generators or directly to duly authorized agents serving New England gas-fired electric generators. EDCs release their respective capacity to the Capacity Manager, subject to provisions of the management agreement between EDC and Capacity Manager. The Capacity Manager can then either combine all similar contracts to allow releases to the market under one contract for each path (i.e., through a contract "roll up") or may release the capacity as separate contracts. In either case, the Capacity Manager is the new shipper and is responsible to pay the max rate.

b. Each month the Capacity Manager invoices each EDC the difference between the max rate, less the capacity release margins, plus the Capacity Management fee. The EDCs will pay the Capacity Manager before the invoices are due to the pipeline to reduce capital requirements of the Capacity Manager. This will require a Capacity Manager with credit adequate to meet pipeline standards and will require the Capacity Manager to have strong accounting processes to ensure each EDC receives the appropriate credits in a transparent and traceable manner[1] The EDC-EC will monitor the release protocols and recommend changes as needed to accommodate the most efficient releasing mechanism to ensure a reliable and cost effective supply to EDC customers.

c. For each capacity release, the Capacity Manager will follow the following process:
   i. The Capacity Manager will issue a request for proposal ("RFP") prior to each release to establish the prearranged shipper.
   ii. Results of the RFP will go directly to the EDC-WC and not the Capacity Manager.
   iii. The EDC-WC will notify the Capacity Manager of the pre-arranged shipper for each contract, as the confidentiality of the generator bids is imperative.
   iv. The Capacity Manager will ensure the release is executed in accordance with Federal Energy Regulatory Commission ("FERC") rules, including pipeline posting (notice) requirements, and will provide the appropriate exemption language in the release.
   v. Capacity will be released on a "non-re-releasable" basis such that it cannot be released by generators once it has been acquired.
   vi. Capacity shall be released on a "recallable" basis should the generator default on payment and/or performance in accordance with this state-approved program.

d. LNG Storage Capacity and Sales
   i. The LNG storage capacity and inventory can be retained by the EDCs, released to the generators or as a bundled service release for a period of 1 year.
   ii. LNG supply will only be available to generators.

Electric Reliability Service Program

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iii. Generators will have the right to call the Capacity Manager for supply, as needed and available throughout the gas day to access gas on a "no-notice" basis.
iv. The quantity of supply made available to electric generators each day during the winter period will be based on inventory and the daily design rule curve.
v. The EDC-WC will determine the design rule curve for each generator who has acquired storage at the beginning of the winter season.
vi. The EDC-WC may determine other criteria such as HDD triggers, or ISO-NE action alert days (i.e. OP4) that may be exceptions to the design rule curve to support the reliability of the region.
vii. LNG supply will be sold to electric generators at the applicable daily midpoint price index or a mutually agreed price between generator and the Capacity Manager under the guidance of the EDC-WC.
viii. Supply purchases for LNG
ix. EDCs will require the Capacity Manager to buy supply for liquefaction.
x. Summer Long Haul capacity will be retained to purchase supply for LNG from the receipt points on the transportation portion of the capacity to the LNG plant on a primary firm basis.
xi. The Capacity Manager will issue an RFP for supply at the Long Haul receipt point.
xii. The Capacity Manager will nominate and schedule supply on the interstate pipelines electronic bulletin board for delivery to LNG facility.
xiii. The Capacity Manager will verify purchased supply with receipt quantities to validate invoices.

e. FERC Capacity Release Rules

Program implementation is contingent upon FERC approval.

Electric Reliability Service Program

January 15, 2016

Figure 1 – Capacity Release Schedule

	Release Term	Award Period (prior to release)	Eligible Participants	Capacity Available for Release (% of Total Managed Capacity)
I	1 Year (ISO-NE FCM1)	3 Years Prior	Generators Only	Up to a maximum of 10%
II	1 Year (ISO-NE FCM2)	2 Years Prior	Generators Only	Up to a maximum of 20% (including releases in I)
III	1 Year	3 Months Prior	Generators Only	Up to a maximum of 30% (including releases in I&II)
IV	Winter Season (Dec – Mar)	3 Months Prior	Generators Only	Up to a maximum of 50% (including releases in I thru III)
V	Summer Season (Apr-Nov)	3 Months Prior	Generators 1st Market 2nd	Up to a maximum of 50% (including releases in I thru III)
VI	Summer Peak (Jul-Aug)	3 Months Prior	Generators 1st	Up to a maximum of 50% (including releases in I thru III)
VII	Monthly (ISO-NE FCM)	2 Months Prior	Generators Only	Up to a maximum of 60% (including releases in I thru VI)
VIII	Monthly (Gas "Bid Week")	7 Business Days (1st) 5 Business Days (2nd)	Generators 1st Market 2nd	Up to a maximum of 60% (Dec-Mar, Jul, Aug) Up to a maximum of 70% (other months) (including releases in I thru VII)
IX	Daily (Incl. Weekends and Holidays)	2 Business Days Prior to Gas Flow Day	Generators 1st Market 2nd	Up to a maximum of 75% (Dec-Feb) Up to a maximum of 85% (Nov, Mar, Jul, Aug) Up to a maximum of 95% (Apr, May, Jun, Sep, Oct) (including releases in I thru VIII)
X	"Intraday"/ "Sameday"	Real-time as available	Generators 1st Market 2nd	Remaining capacity after all other releases subject to LNG reserve requirements during Winter Season.

Testimony of
Richard W. Porter

DIRECT TESTIMONY

OF

RICHARD W. PORTER

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I. Introduction and Qualifications

Q. Mr. Porter, please state your full name and business address.

A. My name is Richard W. Porter. My business address is 5151 San Felipe, Suite 2015, Houston, Texas 77056.

Q. Please state your business position and responsibilities.

A. I am a Director with Black & Veatch Management Consulting LLC (Black & Veatch). In that role, I have consulted for most major North American gas pipeline companies. I am responsible for client management and delivering advisory services to meet client needs. I have over 35 years of experience in the energy industry focused primarily on natural gas business regulatory, strategic, and commercial efforts.

Q. Please summarize your educational background and your professional experience.

A. I graduated from the Louisiana State University in 1976 with a Bachelor of Science in Economics. During the course of my career, I have directed several project teams providing pricing analysis and regulatory support to potential investors regarding pipelines and LNG. I have also developed regulatory strategies, including providing rate case options to natural gas and oil pipeline companies. A copy of my CV is included as Schedule RWP-1.

Q. Have you previously testified before the Rhode Island Public Utilities Commission?

A. No, I have not.

II. Summary of Testimony and Schedules Sponsored

Q. Please describe your responsibilities in this proceeding.

A. On October 23, 2015, The Narragansett Electric Company d/b/a National Grid (National Grid) issued a Request for Proposal entitled "Natural Gas Capacity, Liquefied Natural Gas (LNG), And Natural Gas Storage Procurement" (the RFP). I am responsible for providing: 1) a summary overview of the RFP, 2) a summary description of the responses to the RFP, and 3) an explanation of the review of the responses to determine which were eligible for analysis for evaluation of the long-term economic benefit to electric consumers (Economic Benefit).

Q. Could you please briefly describe your testimony?

A. Based upon a review of the proposals submitted in response to the RFP, I determined that two of the proposals sufficiently satisfied the requirements of the RFP to undergo additional analysis; however, the Tennessee Northeast Direct Project has since been withdrawn. Consequently, I identified the ANE proposal to be evaluated for a determination of Economic Benefit. My colleague, Mr. Gary Wilmes is providing pre-filed direct testimony supporting the Economic Benefit analysis conducted by

Black & Veatch on behalf of National Grid. In addition to the ANE proposal, at the request of the Rhode Island Office Energy Resources (OER) and the Rhode Island Division of Public Utilities and Carriers (Division), several other sensitivities and proposals were evaluated for a determination of Economic Benefit.

Q. Are you sponsoring any schedules?

A. Yes. I am sponsoring the following schedules:

Schedule RWP-1	CV of Richard W. Porter
Schedule RWP-2	Matrix of RFP Requirements and Hierarchy Definitions
Schedule RWP-3	Matrix of Proposals
Schedule RWP-4	Matrix of Key S1 Requirements for all Proposals

III. Summary of the RFP

Q. Please briefly describe the RFP.

A. On October 23, National Grid and Eversource Energy (Eversource) issued a joint RFP. The RFP identified twelve overall requirements, each of which had numerous additional requirements and/or qualifiers. All responses to the RFP were due by November 13, 2015 at 12:00 PM Eastern Time. A summary matrix of the RFP and the associated requirements is included as Schedule RWP-2.

Q. How many responses were received to the RFP?

A. There were eight separate responses received to the RFP. Proposals to the RFP were received from the following respondents:

1. Algonquin Gas Transmission, LLC, Access Northeast Project (ANE);
2. Cavus Energy LLC (Cavus);
3. GDF Suez Gas NA LLC (GDF Suez);
4. Iroquois Gas Transmission LP (Iroquois);
5. Portland Natural Gas Transmission (PNGTS);
6. Repsol Energy North America Corporation (Repsol);
7. Stolt LNGaz Inc. (Stolt); and
8. Tennessee Gas Pipeline Company, LLC, Northeast Energy Direct Project (NED).

I have provided a summary matrix of the responses, included as Schedule RWP-3.

Q. Did all eight of the responses satisfy each of the requirements of the RFP?

A. No, they did not. In fact only two responses satisfied the key requirements of the RFP with respect to providing power fuel for electric generating facilities in multiple ISO load zones. These two responses were for the ANE and the NED projects. The other six responses were determined to be unacceptable responses since, among other things, the incomplete nature of each proposal could have a direct impact on the quality of any economic analysis. Later, I will explain in more detail the process we

developed to determine which responses to the RFP to include in the Economic Benefit analysis modeling.

Q. How does the decision by Tennessee Gas Pipeline on April 21, 2016 to withdraw the Northeast Energy Direct Project impact your review of the RFP responses?

A. The decision had no impact on my review of the RFP responses. The NED response did satisfy the key requirements of the RFP; however, since it was withdrawn, Mr. Wilmes only analyzed the Economic Benefits of the ANE project.

Q. Was Black & Veatch requested by the Rhode Island OER and the Division to conduct additional Economic Benefits analysis?

A. Yes, subsequent to the completion of our initial review Black & Veatch was requested by the OER and the Division to evaluate the GDF SUEZ and Repsol RFP responses, in addition to developing additional sensitivity reference cases. Black & Veatch was asked to provide analysis that included potential Clean Energy RFP responses, and measured the impact of the ANE project in those sensitivity reference cases. Consequently, Mr. Wilmes analyzed the Economic Benefits for these scenarios as well.

Q. What do you mean by Economic Benefit analysis?

A. The Black & Veatch Economic Benefit analysis consists of a combination of detailed

modeling scenarios to determine the impacts of the identified projects on electric consumers in the identified markets. More specifically, the Economic Benefit analysis consists of running a natural gas forecast analysis for the New England region and using the results from such analysis to generate a forecast for the electric market on the region. Mr. Wilmes explains the specifics of the Economic Benefit analysis in his testimony and supporting schedules.

IV. Summary of the Responses

Q. Please briefly summarize the ANE project.

A. The ANE project is a gas pipeline expansion designed to provide up to 900,000 Dth/d of natural gas to points of delivery along existing rights-of-way on Algonquin and Maritimes & Northeast Pipeline LLC (Maritimes). All points on the systems would be available on a firm primary basis. The project will have receipts points at Mahwah, NJ, Ramapo, NY, Brookfield, CT and Acushnet, MA. The project includes construction or upgrade of [redacted] miles of pipeline, modifications to compressor stations infrastructures and the construction of a 6.8 Bcf LNG storage facility at Acushnet, MA. The project is expected to be fully completed by May of 2021.

Q. Please briefly summarize the Cavus project.

A. The Cavus project proposes to provide LNG peak shaving storage service. According to the proposal, Cavus could provide total storage capacity of between 2,000,000 Dth

and 4,000,000 Dth, and a daily withdrawal capacity between 100,000 Dth/d and 600,000 Dth/d. Parties contracting for LNG peak shaving and storage services would be responsible for securing their own pipeline transportation capacity. The Cavus facility is to be located near the Mendon interconnection between Algonquin and TGP and it will be able to serve both pipelines via the Mendon lateral. The project will include the development of a bilateral interconnection with Algonquin and TGP, 5 miles of pipeline, a 2 Bcf LNG storage tank and gas liquefaction infrastructure. The project would be completed by December 2019.

Q. Please briefly summarize the GDF Suez project.

A. The GDF Suez project proposes to provide up to 501,000 MMBtu/d of imported LNG during the months of December through February up to a maximum annual quantity of 45,591,000 MMBtu. The gas would be available at the GDF Suez terminal at Everett, Massachusetts capable of holding 3.4 Bcf. Gas will be transported to New England through Algonquin and TGP systems. GDF Suez proposes to utilize firm pipeline capacity currently under contract to effectuate certain deliveries and proposes that other deliveries could be made by displacement. GDF Suez can provide services starting December 2017.

Q. Please briefly summarize the Iroquois project.

A. This is a pipeline project that requires the expansion of the Iroquois system from its

existing interconnection with the Constitution Pipeline at Wright, NY to an interconnection with Algonquin in Brookfield, CT. The project would provide 200,000 Dth/d to 1,000,000 Dth/d of incremental capacity for Algonquin to deliver into New England. The project is expected to begin operation by November 2018. It will require incremental compression and looping of existing pipeline.

Q. Please briefly summarize the PNGTS project.

A. The PNGTS project is a gas pipeline expansion proposed in conjunction with the expansion of the TransCanada and Iroquois system through its SoNo project. The project would provide up to 600,000 Dth/d from one of three routes with a primary receipt point, at either Dawn, Ontario, Wright, NY, or Niagara, NY/Chippawa, NY. The TransCanada expansion offers firm delivery to East Hereford and then on to PNGTS where gas can be delivered to Dracut, MA. Expansion of the Iroquois system is estimated to be completed by November 2017, while the expansion of TransCanada mainline is estimated for completion by November 2018. Successful completion of the project will require the addition of three new compression facilities, upgrading an existing metering station and adding 24 miles of pipeline looping.

Q. Please briefly summarize the Repsol project.

A. Repsol proposes to provide up to 500,000 MMBtu/d of imported LNG, up to a maximum annual quantity of 22,500,000 MMBtu. The gas would be available at the

Repsol Canaport terminal in New Brunswick, Canada with deliveries to Tennessee Gas Pipeline at Dracut, and Algonquin Gas Transmission at Beverly through the Maritimes pipeline. Repsol proposes to structure an asset management arrangement under which it will utilize its own gas pipeline capacity to deliver the re-gasified LNG to its customers. Repsol can provide service starting November 2016.

Q. Please briefly summarize the Stolt project.

A. Stolt is proposing an LNG export terminal to be located in Quebec, Canada. In its proposal, Stolt offers to provide 72,800 MMBtu of LNG per day. Stolt proposes to distribute natural gas to New England via a combination of maritime ships and trucks. The project is expected to be operational by the third quarter of 2018.

Q. Please briefly summarize the NED project.

A. The NED project was a 300-mile greenfield gas pipeline extending from northern Pennsylvania to eastern Massachusetts. The project was proposed to consist of two paths, a supply path from northeast Pennsylvania to Wright, NY and a market path from Wright, NY to Dracut, MA. As part of the Market Path, modifications of existing laterals or new facilities off of Tennessee Pipeline's 200 Line may have been required to accommodate various primary delivery points. In addition, the project was proposed to include a 3.3 Bcf LNG storage facility to be located on TGP's 200 line the will provide winter peaking services. The market path project proposed to provide up

to 1.3 Bcf/d of which 750,000 Dth/day would be made available for the RFP of incremental gas pipeline capacity into New England. It proposed to establish a new market hub near Wright, NY to provide access to emerging gas supplies from the Marcellus and Utica Shales. Firm primary receipt and delivery capacity is available on NED and downstream on the existing Tennessee Gas Pipeline (TGP) system.

V. Explanation of Proposal Review

Q. What criteria did you develop to determine which proposals were suitable for modeling of the Economic Benefits?

A. Using the data prepared for Schedules RWP-2 and RWP-3, I developed a matrix to determine if each proposal satisfied the key requirements of the RFP. If it did, then it was considered for potential Economic Benefits modeling. If the proposal did not satisfy the key requirements, then it was set aside as unacceptable for modeling purposes. I have included this matrix showing the results of the review of each proposal as Schedule RWP-4.

Q. How did you begin the evaluation that resulted in Schedule RWP-4?

A. On its face, Section B of the RFP is entitled "REQUIREMENTS" and this alone suggests that all items listed under that section are required for the RFP to be acceptable. However, my review is not a review as to the acceptability of the

proposals provided. Rather, my review is one that considers whether or not each respondent has provided sufficient key data to conduct a meaningful Economic Benefits analysis as it pertains to electric consumers. To determine if each proposal satisfied the key requirements. I prepared a matrix recognizing a requirement hierarchy in the RFP in Schedule RWP-2. I then compared each proposal to the requirements to determine if they met the requirements. As I mentioned earlier, only the ANE and the NED projects satisfied the requirements.

Q. Please explain the requirement hierarchy in Schedule RWP-2.

A. The RFP consists of numerous requirements, some of which are quantitative in that they must be supported by data in some form or another. However, there are also qualitative requirements which may be supported by data but may require some additional judgment on the part of the evaluator.

Q. What are some examples of this hierarchy of requirements?

A. The quantitative requirements can be separated into two basic types. I have labeled the most stringent requirements as "S_1" requirements. These S_1 requirements are characterized by the language "must have" or "are required." The S_1 requirements appear where the RFP delineates certain "must have" provisions such as one noted in Section B2, Service Type and Operational Flexibility:

> "*The project of existing facility **must** be able to demonstrate that it can provide the required natural gas on a primary firm basis to generator delivery meters for the duration of the contract." (emphasis added).*

Based upon the plain language, I considered any item that reflected similar must have language to be the highest priority requirement for purposes of this review. Similarly, additional quantitative information might also be required that is requested by other imperative language. This additional information is solicited by language such as "should provide" and I have designated this language as S_2 requirement. An example of a S_2 data requirement also appears in Section B2 where it is noted that:

> *"Bidder **should** indicate the type of service that will be provided and a detailed explanation of the operational flexibility afforded by the respective resource. (emphasis added).*

Finally, there are qualitative requirements which may add value and were labeled as "Q_1" requirements. One example of the qualitative proposals is provided in Section B10 Audited Financial Statements, Annual Reports, and Credit Ratings, which provides:

> *"Preference will be given to entities with a credit rating of investment grade or above and with a positive outlook.*

However, since the purpose of my review was solely to determine if the responses provided sufficient and satisfactory data to conduct the Economic Benefits modeling

in a manner consistent with the RFP, I did not need to consider any of this qualitative data.

Q. Please explain Schedule RWP-4.

A. Schedule RWP-4 is a matrix that lists key S_1 requirements stated in the RFP, and then identifies if each response satisfies the requirement. A review of the matrix shows that only the ANE and the NED projects satisfy all of the Key S_1 requirements. Consequently, only these two projects require any additional review.

Q. Why were some of the proposals eliminated by the methodology illustrated in Schedule RWP-4?

A. The proposals that were eliminated for consideration for Economic Benefit analysis did not satisfy all of the S_1 requirements. For example, the S_1 requirement detailed in Section B3, Quantity provides:

> *"Bids for LNG and storage must also include transportation via interstate pipeline to generators in New England on a primary firm basis."*

The LNG proposals submitted by Cavus, GDF Suez and Stolt did not fully meet this requirement, and thus, they all were eliminated from further consideration for

Economic Benefit analysis.[1] Similarly, the proposals submitted by Iroquois, PNGTS and Repsol did not meet all of the requirements. In the case of each of these proposals, a shortcoming was associated with the S_1 requirement identified in B1 Delivery and Receipt locations where it is stated that:

> *"Bidders are required to demonstrate that the proposal will provide reliable delivery of natural gas on a primary firm basis to multiple generating facilities on critical peak days across multiple load zones."*

The Iroquois, PNGTS and Repsol proposals did not satisfy this requirement.

Q. Did any proposal satisfy all of the S_1 and S_2 requirements, including the extended requirements?

A. Yes, as shown in Schedule RWP-4, the ANE Project and the NED Project both satisfied these requirements. However, the NED Project was withdrawn by Tennessee Gas Pipeline, so only the ANE Project warranted further Economic Benefits modeling.

Q. What did you do with the results of your review?

A. Mr. Wilmes conducted the Economic Benefits modeling.

VI. Conclusion

Q. Does this conclude your pre-filed testimony in this proceeding?

A. Yes. It does.

[1] GDF Suez did provide additional information related to primary firm deliverability to power generators, but did not hold sufficient primary firm capacity to meet the minimum quantity requirement.

Schedule RWP-1
Curriculum Vitae

Richard Porter

DIRECTOR

Specialization:
Natural Gas Regulation & Strategy; Pipeline Cost of Service and Rate Design; Pipeline Certificates; Pipeline Tariffs and Services; NGPA Section 311 Rates and Terms of Service; Expert Testimony; Regulatory Compliance Training and Programs; Regulatory Training; Regulatory Policy Analysis; Regulatory Strategy Development; Turnkey Regulatory Services

Education
- BS , Economics Louisiana State University, 1976

Year Career Started
1976

Year Started with B&V
2011

Mr. Porter is a Director in Black & Veatch's Management Consulting Division with more than 30 years of midstream regulatory experience having worked or consulted for most major North American gas pipelines companies. His tactically focused regulatory strategies are directed to add value to the regulatory process, promoting the Client's commercial and financial goals. Drawing on his deep industry experience, and with the support of the extensive skills and breadth of the Black & Veatch team, Mr. Porter can coordinate and support any comprehensive regulatory, strategic or commercial effort.

He has a consistent reputation for producing solutions that increase operating margins; managing complex shipper regulatory and commercial negotiations to achieve financial goals; demonstrating industry knowledge, critical thinking, organization and communication skills as an expert witness; providing strategy, planning and implementation of new pipeline projects and new services; participating in pipeline system and supply development programs; designing new tariffs and tariff features to capture market opportunities and promote earnings growth; developing, filing and implementing innovative cost of services and rate designs; and preparing FERC rulemaking and policy analysis, commentary and strategy development.

Mr. Porter began his natural gas regulatory career with Panhandle Eastern Pipe Line Company where, among other things, he provided regulatory support for the development of natural gas supply projects. At Arkla Energy Resources he was instrumental in the implementation of open access transportation pursuant to FERC Order 436. As Assistant Vice President at ANR Pipeline he directed the regulatory planning, development and implementation of multiple pipeline expansions, Greenfield pipeline projects, new services offerings, and rate case filings, settlements and litigation. Later at Enterprise Products Partners he developed regulatory management and strategy for offshore pipelines, storage fields and multiple intrastate natural gas pipelines. Prior to joining Black & Veatch he founded The Pythia Group, LLC and provided innovative regulatory consulting services to pipelines, pipeline shippers, local distribution companies and natural gas marketers.

PROJECT EXPERIENCE

LDC / Hinshaw Pipeline & Storage Rate Case Support

Mr. Porter directed the project team that provided a benchmark study to evaluate the client's costs and services vis-as-vis other similarly situated companies in the country. The tasks conducted also provided for the review of various costing and allocation methods utilized by other companies and evaluation of the potential for the use of those methods on client's system.

LNG Export Project Pricing & Regulatory Support

As part of the Black & Veatch team, Mr. Porter provided pricing analysis and regulatory support to a potential investor / exporter of LNG from the United States. The project required the review of the pricing and terms of service of the export terminal and the connected natural gas pipelines.

Oil Pipeline Peer Group, Rate Case and Regulatory Analysis

On behalf of a major oil producer, Mr. Porter led a team that was engaged to provide a second opinion and review rate case options for an oil pipeline. We evaluated the operations and financial performance of the pipeline relative to a peer group and developed studies supporting revenue enhancement strategies and rate case filings before federal and state regulatory agencies. We produced a negotiated settlement with the shippers that significantly increased cash flow and operating margins.

Interstate Pipeline Acquisition Support and Certificate Application

Mr. Porter directed the preparation of a Natural Gas Act §7(c) application for a startup entity to acquire natural gas pipeline assets from another natural gas pipeline. Mr. Porter's responsibilities included the oversight and preparation of all exhibits, including the analysis and design of service rates, service development, and tariff preparation. As a result of Mr. Porter's efforts, the pipeline implemented innovative, market-responsive tariff services and pricing.

Greenfield Pipeline for Power Generation Facility

Black & Veatch was retained by a confidential client to develop a regulatory strategy for a Greenfield pipeline to provide natural gas for a proposed electric generation facility. Mr. Porter developed an overall regulatory strategy, cost studies, pipeline services and rate design.

PRIOR PROJECT EXPERIENCE

Regulatory Due Diligence

On behalf of the investors, Mr. Porter was retained to provide a regulatory review of an LNG export facility and its affiliated interstate pipeline. The export facility has subsequently received its required authority from DOE and FERC.

Rate Case Analysis and Expert Testimony

On behalf of a shipper trial group, he provided analysis of the pipeline company initial rate increase filing, analysis of FERC Staff Top Sheets, and assisted in the development of settlement positions. He was also engaged to provide expert testimony in the event of litigation.

Interstate Pipeline Rate Case

On behalf of a midstream entity, he developed a rate increase filing, assisting in the development of various cost of service and rate design positions. He provided expert witness testimony and economic analysis regarding the

applicability of a supplemental management fee and an economically based remaining depreciable life. The case was successfully settled.

Regulatory Due Diligence

On behalf of the investors, Mr. Porter was retained to provide a regulatory review of an intrastate gas pipeline constructed to export shale gas to intrastate and interstate markets.

Regulatory Due Diligence

On behalf of a midstream entity, he evaluated the regulated assets associated with the potential acquisition of assets with a book value exceeding $4B, resulting from FTC required assets sales associated with the acquisition of a major interstate pipeline. Mr. Porter prepared an analysis reviewing the pipelines' certificate authority, cost of service and rates, tariff, regulatory compliance status and contract obligations. Mr. Porter made specific recommendations regarding issues to be addressed prior to closing, as well as proposals for addressing various earnings related issues post closing.

Pipeline Rate Case Preparation and Expert Testimony

On behalf of a midstream entity, he developed a rate increase filing for one of the companies' pipelines, assisting in the development of various cost of service and rate design positions. The pipeline was fully depreciated and presented special challenges in the rate case process. He provided expert witness testimony and economic analysis regarding the applicability of a supplemental management fee and an economically based remaining depreciable life. The case was successfully settled.

Cost and Revenue Study Analysis and Settlement Support

On behalf of a shipper trial group, he provided technical analysis of the pipelines' as-filed cost and revenue study. As an active participant in the settlement discussions on behalf of the trial group, he analyzed the various settlement options and developed settlement positions to help the group achieve their objectives. The case was successfully settled and the client's goals achieved.

Regulatory Compliance

On behalf of a marketer of natural gas, Mr. Porter conducted an analysis of current compliance activities and noted areas for improvement. He designed and provided a comprehensive compliance program tailored specifically to the business model of the client.

LNG Takeaway Pipeline Project

On behalf of a midstream entity, Mr. Porter directed the initial regulatory and economic analysis, later participating in the negotiation of precedent agreements and service rates, and managing the development of terms of service and recourse rates.

Colorado Residue Line Greenfield Project

On behalf of a midstream entity, Mr. Porter developed a new interstate natural gas pipeline service which permitted the gathering / processing company to hold firm capacity on the residue line and act as the nominating, scheduling and billing agent for its own gathering and processing customers. He directed the initial regulatory and economic analysis for the project and participated in the negotiation of precedent agreements and service rates. He also oversaw the development of terms of service and recourse rates. Mr. Porter later was responsible for negotiating and filing for the approval of the terms of service and rates at the FERC.

Section 311 Rate Cases

On behalf of a midstream entity, he oversaw the planning, development, filing and settlement of various Section 311 proceedings. The pipelines involved often had contemporaneous regulatory requirements associated with their respective states and required coordination of the process with the FERC and the various state regulatory commissions. These filings also included extensive revisions to the Statements of Operating Conditions for the pipelines.

Natural Gas Shale Greenfield Pipeline Projects

On behalf of a midstream entity he directed the initial regulatory and economic analysis of the evacuation pipeline projects. He participated in the negotiation of precedent agreements and service rates and oversaw the development of terms of service and recourse rates. Subsequently, he negotiated and filed for the approval of the terms of service and rates at the FERC.

Litigation Support at US Court of Appeals for the DC Circuit

On behalf of an interstate pipeline and a storage provider Mr. Porter oversaw the preparation and argument of a successful appeal regarding the proper constitution of the proxy group used to determine the cost of equity for interstate pipelines. The Court's remand of the FERC Order coincided with the issuance of a new FERC policy statement on the composition of pipeline proxy groups.

Design and Implementation of FERC Standards of Conduct

Acting as the Chief Compliance Officer he developed and oversaw the implementation of a comprehensive compliance program in accordance with the FERC Standards of Conduct. Mr. Porter conducted companywide interviews and provided documentation for regulatory processes throughout the company. He also implemented the initial training module circulated to the company personnel.

Natural Gas Pipeline Power Generation Transportation Rates

Mr. Porter oversaw the preparation and filing of the certificate application for the Gulfstream Pipeline. Among other things, he was responsible for the development of the innovative rate design methodology used to price power

generation services that required non-uniform rates of flow. He later adapted that same design methodology for a major interstate pipeline to promote the development of power generation load and maximize pipeline revenue opportunities.

Deepwater Pipeline Expansion

On behalf of an offshore pipeline, Mr. Porter provided the regulatory support for the partnerships' efforts to attach natural gas supplied in the deep waters of the Gulf of Mexico. He developed the overall regulatory strategy, participated in the contract negotiations and ensured that the service seamlessly integrated into those of the downstream pipelines. Mr. Porter made specific recommendations that were implemented to promote the long term revenue stability of the pipeline.

Rate Case Litigation and Settlement

Mr. Porter managed three months of litigation of a Section 4 rate case for a major interstate pipeline and used the litigation record as a basis to achieve a successful settlement of all issues in the proceeding. For three days, Mr. Porter presented extensive testimony regarding the appropriate rate design method to be utilized. Later, as part of the settlement, he provided an affidavit attesting to a methodology to be utilized for the design of rates for short term services.

Gas Supply Acquisition Support

Mr. Porter provided regulatory and pricing support as part of a team charged with attaching new gas supply to the pipeline system. The negotiations were often focused on new supplies in the Gulf of Mexico and generally required construction of significant new facilities, and consequently long-term contractual commitments to ensure capital recovery and promote supply longevity.

Pipeline Industry Competitive Analysis

To evaluate the ability to compete in a more competitive environment, Mr. Porter headed a team charged with analyzing the competitive positions of the major natural gas pipelines. The areas evaluated included rates and services; operations and capacity; commercial and system flexibility; and current and future markets. The group made specific recommendations to make the company more competitive vis-à-vis the other pipelines.

PRIOR INDUSTRY EXPERIENCE

The Pythia Group LLC, Natural Gas Regulatory Consultants | Founder/Manager | 2009– 2011

- Retained to provide regulatory due diligence for a midstream company evaluating the purchase of an interstate pipeline.
- Retained in various FERC rate cases as expert witness and to provide analysis for a client groups

Enterprise Products Partners | Director Regulatory Affairs | 2004–2009

- Conceived and implemented solutions to recover $80M of stranded pipeline investment
- Developed an innovative market hub strategy, enhancing margins for gatherers and processors

El Paso Corporation, ANR Pipeline Company | Director Regulatory Affairs | 2001–2004

- Developed and implemented strategy, and acted as the company witness in litigation before the FERC with exposure exceeding $100 million
- Managed the litigation of proxy group issue before the Court of Appeals for the DC Circuit which eventually led to FERC establishment of new policy regarding proxy groups

Coastal Corporation, ANR Pipeline Company | Assistant Vice President Regulatory Affairs |1992–2001

- Created the time-of day rates concept for power generation transport services approved for Gulfstream pipeline
- Responsible for the development and application of rate case strategic and financial positions used throughout its last rate case, negotiating a successful settlement

CenterPoint Energy Gas Transmission | Manager Regulatory Affairs |1986–1992

- Drafted, filed and received approval for the company's first open access tariff and designed the associated transportation rates
- Developed, filed, testified and coordinated rate cases before the Arkansas Public Service Commission

Panhandle Eastern Pipe Line Company | Rate Analyst, Senior Rate Analyst, Assistant Manager Certificates | 1979–1985

- Participated in the development and presentation of system expansion proposals to various producers seeking to attach supply to the pipelines
- Responsible for a competitive analysis study to determine the pipeline's ability to compete in an open access environment

SELECTED PUBLICATIONS AND PRESENTATIONS

"Fundamentals of Natural Gas Regulation: A Primer," (in progress)

"Natural Gas Pipeline Rate Design: A Dismal Science or Zen Experience?", Presented at University of Illinois Center for Business and Regulation, American Gas Association Rates Fundamentals, July 2014

"GEMS: Gas – Electric Market Synchronization", Presented at American Public Power Association National Conference, June 2014

"Regulatory Uncertainty Slows Pipeline Development", 2013 Strategic Directions in the North American Natural Gas Industry, October 2013

"C³ – Issues for an Expanding Energy Market", Presented at Energy Bar Association of Houston Quarterly Luncheon, July 2013

"Natural Gas Supply Planning", (co-authored with Ann Donnelly, Ph.D.), 2013 Strategic Directions in the US Electric Industry, June 2013

"Managing the Regulatory Risk of Infrastructure Investment," Oil and Gas Financial Journal, (February 15, 2013)

"Ratemaking Basics," Fundamentals of Natural Gas Accounting, Southern Gas Association (May 19, 2011)

"Rethinking the Secondary Market for §311 and Hinshaw Services," FERC Updates (August 16, 2010)

"The Scope of Compliance," FERC Updates (August 3, 2010)

"Ratemaking Basics," Fundamentals of Natural Gas Accounting, Southern Gas Association (June 7, 2010)

"FERC Revises Reporting Requirements of Intrastate Pipelines," FERC Updates (May 24, 2010)

"FERC Refines Fuel Retention Policy," FERC Updates (May 21, 2010)

"FERC Defines Civil Penalty Guidelines," FERC Updates (March 20, 2010)

REGULATORY EXPERIENCE AND EXPERT WITNESS TESTIMONY

Recent Engagements

- **Docket No. RP10-147 – Natural Gas Pipe Line:** Retained as expert witness and to provide analysis for a producer / shipper in this cost and revenue study proceeding
- **Docket No. RP10-149 – Great Lakes Gas Transmission:** Retained as expert witness and to provide analysis for the Wisconsin Distributor Group in this cost and revenue study proceeding
- **Docket No. RP10-1383 – Enbridge Offshore Pipelines (UTOS) LLC:** Supported development of rate case and retained as an expert witness for rate design, management fee and economic life, and to assist in discovery and settlement of proceeding.
- **Docket No. RP11-1435 – Columbia Gulf Transmission Company:** Retained as expert witness and to provide analysis for a client group consisting of major producers and natural gas marketers.

- **Docket No. RP11-1566 – Tennessee Gas Pipeline Company:** Retained as expert witness and to provide rate analysis for a client group consisting of the northeast local distribution companies.
- **Docket No. RP11-1957 – Stingray Pipeline Company, L.L.C.:** Supported development of rate case and retained as an expert witness for rate design and economic life, and to assist in discovery and settlement of proceeding.
- **Docket No. CP12-489 – Kinetica Energy Express, LLC:** Prepared certificate application, including design of services, rates and tariff for acquisition of natural gas pipeline facilities from Tennessee Gas Pipeline. Created innovative services and tariff mechanisms to promote earnings growth.
- **Docket No. IS13-563 – Red Butte Pipe Line Company:** Prepared cost of service, rate studies and strategic support for settlement negotiations resulting in the filing of a stipulation and agreement with the FERC.
- **Docket No. 50045-22-PR-13 – Red Butte Pipe Line Company:** Prepared cost of service, rate studies and strategies for rate case filing before the Wyoming Public Service Commission and filed expert testimony on cost of service, rate design and cost of capital.

Historical Experience

- **Docket No. RP78-62 – Panhandle Eastern Pipe Line Company:** Prepared studies and analysis to support litigation of income tax normalization issues.
- **Docket No. RP86-106 – Arkla Energy Resources:** Drafted the Order 436 tariff and the transportation rate design
- **Docket No. RP88-45 – Arkla Energy Resources:** Filed prepared testimony on rate design
- **Docket No. RP92-50 – High Island Offshore System:** Directed rate case development and strategy, filed prepared testimony on rate design and negotiated the settlement of the rate case.
- **Docket No. RS92-64 – High Island Offshore System:** Drafted, the company's Order 636 open access tariff and rate design
- **Docket No. RS92-88 – UT Offshore System:** Drafted the company's Order 636 open access tariff and rate design, including required rate increase mitigation
- **Docket No. RP93-59 – High Island Offshore System:** Directed rate case development and strategy, filed prepared testimony on rate design and negotiated a settlement of the rate case
- **Docket No. RP94-43 - ANR Pipeline Company:** Filed prepared testimony on rate design. Developed settlement positions for the company, managed the litigation of the rate case and provided expert testimony on overall cost of service, fixed and variable cost determination and classification, cost

allocation among services and rate components, overall rate design, distance sensitive and term differentiated rates.

- **Docket No. RP94-161 – UT Offshore System:** Developed strategy and filed prepared testimony on rate design, management fee and negotiated a settlement of the rate case.
- **Docket No. RP94-162 - High Island Offshore System:** Directed development and strategy, filed prepared testimony on rate design, management fee and negotiated settlement of the rate case.
- **Docket No. CP00-6 – Gulfstream Natural Gas:** Directed the certificated application, developed the pro forma tariff for services and created the rate design to price power generation services.
- **Docket No. PR00-9 – Enterprise Texas Pipeline Company:** Successfully concluded a NGPA §311 rate case that spanned 3 years, including winning reversal of a prior Commission decision which ordered the pipeline to unbundle its gathering and transmission services.
- **Docket No. RP00-30 - ANR Pipeline Company:** In response to the growing demand for services with non-uniform rates of flow, developed Rate Schedule FTS-3 which priced daily service in accordance with hourly capacity requirements.
- **Docket No. RP00-332 - ANR Pipeline Company:** Drafted and negotiated Order 637 Open Access Tariff.
- **Docket No. CP01-69 – Petal Gas Storage:** Directed rehearing requests and eventual appeal before the US Court of Appeals for the DC Circuit of the composition of the proxy group which the courts remanded to the Commission. Subsequently negotiated a settlement establishing a new return on equity and a surcharge to recover historical under recovery.
- **Docket No. RP02-335 - ANR Pipeline Company:** Primary witness on appropriateness of company cash-out mechanism; proposed modifications to mechanism to permit recovery of historical under collections and to establish high-low pricing to minimize gaming and future under collections.
- **Docket No. RP03-221 - High Island Offshore System:** Directed development and strategy and filed prepared testimony on policy and management fee. Coordinated litigation of rate case and directed rehearing requests and eventual court appeal of the composition of the proxy group which the courts remanded to the Commission. Subsequently negotiated a settlement that established a new return on equity and a surcharge to recover historical cost under recovery.
- **FERC Order 2004:** Prepared analysis and direction for company on implementation of Standards of Conduct. Was designated as the Chief Compliance Officer and among other things designed first SOC training program for the company

- **Docket No. 29863:** Alabama Public Service Commission proceeding for certificate authority to operate Enterprise Alabama Intrastate Pipeline; filed certificate and provided expert testimony before the Commission
- **Gas Utilities Docket No. 9663:** Directed this Railroad Commission of Texas proceeding to eliminate Commission required sales for resale obligation from LoVaca Gathering proceeding
- **Docket No. PR06-18 - Acadian Gas Pipeline System:** Filed for approval of rates for NGPA Section 311 services
- **Docket No. PR06-19 - Cypress Gas Pipeline LLC:** Filed for approval of rates for NGPA Section 311 services
- **Docket No. RP06-244 - High Island Offshore System:** Produced a fuel matrix filing that provided for the monthly true up of company use, as well as a recapture of past amounts and negotiated a settlement establishing the mechanism
- **Docket No. RP06-540 - High Island Offshore System:** Directed development and strategy of the rate case, filing prepared testimony as the policy, economic life and management fee witness and negotiated a settlement of the rate case
- **Docket No. PR07-12 – Enterprise Texas Pipeline LLC:** Filed for approval of rates for NGPA Section 311 services
- **Docket No. PR07-13 Enterprise Alabama Intrastate, LLC:** Filed for approval of rates for NGPA Section 311 services
- **Docket No. PR08-30 – Enterprise Texas Pipeline Company:** Filed for incremental pricing for NGPA§ 311 service on an extension of the pipeline through the Barnett Shale and successfully negotiated a settlement
- **Docket No. PR09-28 - Acadian Gas Pipeline System:** Filed for approval of rates for NGPA Section 311 services
- **Docket No. PR09-29 - Cypress Gas Pipeline LLC:** Filed for approval of rates for NGPA Section 311 services
- **Docket No. RP09-487 - High Island Offshore System:** Directed development and strategy of the rate case, filing prepared testimony as the policy, economic life, rate design refunctionalization and management fee witness
- **Docket No. CP09-91 - High Island Offshore System:** Developed and filed to refunctionalize HIOS facilities upstream of High Island Block A-264 and received Commission approval for the refunctionalization on September 30, 2009

Schedule RWP-2
RFP Matrix

Schedule RWP-2 Matrix RFP Requirements and Hierarchy Definitions

HIERARCHY	TYPE	LANGUAGE
S_1	Quantitative	"Must Have", "Are Required"
S_2	Quantitative	"Should Provide"
Q_1	Qualitative	"Encouraged to", "Is Preferred"

REQUIREMENTS	DESCRIPTION	HIERARCHY
Delivery & Receipt Locations	Physical Delivery Point & MDQ	S_2
	Physical Receipt Point & MDQ	S_2
	Supporting Upstream Supplies	S_2
	Pipeline Receipt Liquidity / Upstream Constraints	S_2
	LNG supply source / country of origin / transport mode	S_2
	NE Power Gen Served & Peak Quantities	S_1
	Delivery Point Flexibility / Multiple Generator Deliveries	Q_1
	Provides Primary Firm Path to power generation across multiple load zones during Winter Peak hours	S_1
	Force Majeure shall not include any act, event or circumstances occurring in a country in which LNG is produced or procured or any event that affects an LNG vessel prior to such vessel's departure from the LNG Loading Facilities	S_1
Service Type & Operational Flexibility	Type of Service Provided	S_2
	Operational Flexibility	S_2
	Firm Primary to Generation for Contract Term	S_1
Quantity	Provide between 500,000 MMBtu/d and 2,000,000 MMBtu/d	S_1
	Identify generation facilities to be served and at what level	S_2
	Total Project Size	S_2
	Committed Capacity	S_2

REQUIREMENTS	DESCRIPTION	HIERARCHY
	Quantity Offered to Others	S_2
	Economically Viable Quantity	S_2
	LNG/Storage Only – Max Daily Quantity & Max Annual Quantity	S_1
	LNG/Storage Only - Availability for winter reinjection	S_1
	LNG/Storage - Firm Point for injection	S_1
	LNG/Storage - Interstate transport in NE on Firm Primary	S_1
Price	Price Including Fixed or Variable Charges	S_1
	Specify Max Rate to be charged	S_1
	Cost of Service Rate Must Supply Max Rate	S_1
	Identify Relevant Pricing Terms (e.g., indices)	S_1
	Offer Firm through December 31, 2015	S_1
Contract Term & Renewal Rights	Identify Expected In-Service Date	S_1
	Identify Guaranteed In-Service Date	S_1
	Minimum Required Term must be between 15 and 20 years	S_1
Pro-Forma Contract / Precedent Agreement	Submit Pro-Forma Agreement to the type of service offered	S_1
Tariffs & Pro-Forma Service Agreements	Submit Existing & Proposed Tariff and Pro-Forma Service Agreements	S_2
	Submit Provisions for No-Notice Service	S_2
Documentation of Development & Management Experience	Documentation of bidders natural gas projects developed and managed	S_1
	Highlight of bidders experience in Northeastern US Markets	S_2
Regulatory/ Siting/ Approvals/ Timing	Provide Required Regulatory/Siting Approvals	S_2
	Itemize all assets/ facilities/permits required to provide the proposed services	S_1
	Timely expected benefits and high probability of success	Q_1
Audited Financial Statements/ Annual Reports/ Credit Ratings	Provide copy of Audited Financials for the past 3 years and the most recent annual report	S_2

REQUIREMENTS	DESCRIPTION	HIERARCHY
	Copy of Current Credit Rating	Q_1
Business Condition / Financial Reports	Provide Corporate Overview/Profile	S_2
	Provide Corporate Ownership Structure	S_2
	Provide information on how the project will be financed.	S_2
	Proven operating experience and financial strength.	Q_1
Disclosures	Provide details of legal disputes and other matters.	S_2
	Describe potential conflicts of interests, claims or disputes.	S_2

Schedule RWP-3
Matrix of Proposals

Schedule RWP-3 Matrix of Proposals

RFP RESPONSE NAME	PNGTS - SONOS	IROQUOIS-CONSTITUTION	CAVUS	GDF SUEZ	REPSOL	TENNESSEE GAS PIPELINE NORTHEAST ENERGY DIRECT	ALGONQUIN GAS TRANSMISSION ACCESS NORTHEAST	STOLT LNGAZ
Natural Gas Infrastructure Type	Natural Gas Pipeline	Natural Gas Pipeline	LNG Peakshaving Storage	LNG Import Terminal	LNG Import Terminal	Natural Gas Pipeline	Natural Gas Pipeline and LNG Storage	LNG Import Terminal
Proposed In-Service Date	100,000 Dth/d by Nov 2018 and 600,000 Dth/d MMBtu by Nov 2019	Nov 2018	Dec 2019	Dec 2017	Nov 2016	Nov 2018	Fall 2018 with additional increments in 2019 and 2021	Q3 2018
Total Maximum Daily Transportation Quantity (MDQ)	600,000 Dth/d on TCPL Mainline and IRQ to PNGTS	Incremental deliveries of 200,000 Dth/d to 1,000,000 Dth/d from the proposed Constitution pipeline	Withdrawal capabilities (100,000 Dth/d to 600,000 Dth/d) (Total Storage capacity of 2,000,000 to 4,000,000 Dth)	501,000 MMBtu/day (Dec through Feb)	500,000 MMBtu/day, Max annual quantity of 22,500,000 MMBtu	750,000 Dth/d NED Market Path, 450,000 Dth/d NED Supply Path	[redacted]	72,800 MMBtu/d
Primary Firm Path to Power Generation	Yes, Primary Firm Path to Power Generation on PNGTS.	Yes, limited Primary Firm from Constitution interconnect at Wright, NY to existing interconnect with AGT at Brookfield, CT.	None. Secondary Firm on AGT/TGP Mendon lateral	Yes, Primary Firm limited to surrounding units and firm backhaul capacity on AGT and TGP to serve ISO-N.E	Yes, Primary Firm Path to power generation on MN&E.	Yes, Primary Firm to Power Generation on TGP.	Yes, Primary Firm Path to power generation along AGT and MN&E.	No, carrier or trucking to Boston Area Terminal
Primary Receipt Point	EDCs must select from Dawn,	Wright, NY	AGT Mendon Lateral	Everett Marine	Canaport LNG Terminal at	Wright, NY, TGP Zn 4 300L Pool,	Mahwah, NJ (TGP), Ramapo,	TQM Quebec

RFP RESPONSE NAME	PNGTS - SONOS	IROQUOIS-CONSTITUTION	CAVUS	GDF SUEZ	REPSOL	TENNESSEE GAS PIPELINE NORTHEAST ENERGY DIRECT	ALGONQUIN GAS TRANSMISSION ACCESS NORTHEAST	STOLT LNGAZ
	Niagara, Chippawa, or Waddington as Primary Receipt Point			Terminal or Neptune Deepwater Port	New Brunswick	LNG Storage in MA	NY (Millennium), Brookfield, CT (IGT) and Acushnet, MA.	
Primary Delivery Point	TCPL/IRQ to East Hereford, with final deliverability to TGP at Dracut, MA	Delivery at Algonquin interconnect at Brookfield, CT	AGT Mendon Lateral	Boston Gas, Algonquin Gas Transmission, Tennessee Gas Transmission, or Mystic Power Generation Plant	Up to 730,000 Dth/d to TGP at Dracut, MA and AGT at Beverly, MA	Dracut, MA and most of existing TGP delivery points.	Along existing AGT ROW	None

Schedule RWP-4
Matrix of Key S1 Requ.

Schedule RWP-4 Matrix of Key S_1 Requirements For All Proposals

KEY REQUIREMENT	PNGTS - SONOS	IROQUOIS - CONSTITUTION	CAVUS	GDF SUEZ	REPSOL	TENNESSEE GAS PIPELINE NORTHEAST ENERGY DIRECT	ALGONQUIN GAS TRANSMISSION ACCESS NORTHEAST	STOLT LNGAZ
Provides primary firm path to multiple power generating facilities across multiple load zones on critical peak days	**No**	**No**	**No**	**Yes***	**No**	**Yes**	**Yes**	**No**
Provides between 500,000 MMBtu/d and 2,000,000 MMBtu/d	**Yes**	**Yes**	**Yes**	**No***	**Yes**	**Yes**	**Yes**	**No**
Identifies Expected In-Service Date	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Minimum Required Term must be between 15 and 20 years	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Force Majeure shall not include any act, event or circumstances occurring in a country in which LNG is produced or procured or any event that affects an LNG vessel prior to such vessel's departure from the LNG Loading Facilities	**Yes**	**Yes**	**Yes**	**No**	**No**	**Yes**	**Yes**	**Yes**

*GDF Suez did provide additional information related to primary firm deliverability to power generators, but did not hold sufficient primary capacity to meet minimum quantity requirements.

Testimony of
Gary J. Wilmes

DIRECT TESTIMONY

OF

GARY J. WILMES

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I. Introduction and Qualifications

Q. Mr. Wilmes, please state your full name and business address.

A. My name is Gary J. Wilmes, P.E. My business address is 11401 Lamar Avenue, Overland Park, KS 66211.

Q. Please state your business position and responsibilities.

A. I am a Senior Consultant for Black & Veatch Management Consulting, LLC. In that role, I have led numerous integrated resource and electric system planning studies, and have extensive experience in economic analysis and production cost modeling. I have over 24 years of experience in preparing electric market assessments, electric utility generation expansion plans, and production cost projections. I have extensive experience with the use of commercial electric price forecasting tools such as ABB/Ventyx Market Power and PROMOD IV software.

Q. Please summarize your educational background and your professional experience.

A. I received a Bachelor of Science (with high distinction) in Agricultural Engineering in 1987 and Master of Science in Manufacturing Systems Engineering in 1992, both from the University of Nebraska-Lincoln. I am a Registered Engineer licensed in Kansas. Prior to joining Black & Veatch, I was a Research Engineer at the University of Nebraska at Lincoln where I performed research to measure crop yield response to

timings and quantities of fertilizer and water applications. A copy of my CV is included as Schedule GJW-4.

Q. Have you previously testified before the Rhode Island Public Utilities Commission?

A. No, I have not.

II. Summary of Testimony and Schedules Sponsored

Q. Please describe your responsibilities in this proceeding.

A. On October 23, 2015, The Narragansett Electric Company d/b/a National Grid (National Grid) issued a Request for Proposal entitled "Natural Gas Capacity, Liquefied Natural Gas (LNG), And Natural Gas Storage Procurement (the RFP). I am responsible for providing an evaluation of the long-term economic benefits to electric consumers (Economic Benefits) from the RFP responses. In my testimony, I am sponsoring the report titled, "Evaluation of Long-Term Economic Benefits from Proposed Incremental Energy Infrastructure into New England," included as Schedule GJW-3. Black & Veatch's report focuses on the impact of the Algonquin Gas Transmission's Access Northeast (ANE) proposal to regional natural gas and electricity prices as compared to different reference cases, the associated long-term economic benefits to New England electric consumers and the regional air emissions

impacts of the project. Black & Veatch's report also evaluated the economic benefits of the GDF Suez and Repsol LNG import proposals.

Q. Are you sponsoring any schedules?

A. Yes. I am sponsoring the following schedules:

Schedule GJW-1	Summary Table of Long-term Economic Benefits and Cost to Regional Electric Consumers
Schedule GJW-2	Regional Emissions Impact of ANE
Schedule GJW-3	Black & Veatch Report, "Evaluation of Long-Term Economic Benefits from Proposed Incremental Energy Infrastructure into New England"
Schedule GJW-4	CV of Gary J. Wilmes

Q. Could you please briefly describe your testimony?

A. Yes. Based on Black & Veatch's assessment, New England's projected firm LDC gas demand growth and the increasing dependence on gas-fired generation support the development of the ANE project. The ANE project offers incremental access to gas supplies in the Marcellus and Utica Shale production basins, while providing additional firm path deliverability to numerous LDC city-gates and power generators across New England during peak winter periods. Increasing gas pipeline deliverability backed by firm low cost gas supplies across New England will offset the steady

declines in pipeline imports observed on Maritimes and Northeast Pipeline and LNG imports from Canaport and Everett.

Compared to the Reference Case, our analysis estimates that ANE would provide $1.1 billion (nominal dollars) in annual levelized electric consumer net benefits over the contract length (2019-2038), under normal weather conditions, as shown in Schedule GJW-3.

Pursuant to Rhode Island's Affordable Clean Energy Security Act, National Grid consulted with the Office of Energy Resources (OER) and the Rhode Island Division of Public Utilities and Carriers (Division) regarding the procurement of natural gas capacity. As a result of that consultation, Black & Veatch developed two sensitivity reference cases that build upon the assumptions in the original Reference Case by adding incremental renewable energy projects that could result from the New England Clean Energy RFP. Compared to both Sensitivity Reference Cases A and B, the ANE project still creates approximately $0.4 Billion in annual levelized electric consumer net benefits in each case over the contract length.

Although none of the LNG solutions offered in response to National Grid's RFP met the key requirements of the RFP, as explained in the pre-filed testimony of Mr. Porter, Black & Veatch analyzed the GDF Suez and Repsol responses and evaluated the long-

term economic benefits of each also as a result of National Grid's consultation with the OER and the Division.

The proposed LNG import solutions do create long-term benefits to electric consumers, though the net benefits are of lower magnitude and the benefit-to-cost ratios are lower when compared to the modeling scenario with ANE. As shown in Schedule GJW-3, Table 7, the GDF Suez and Repsol proposal are projected to yield $0.6 and $0.2 billion, respectively, in annual levelized electric consumer net benefits over the contract length.

Black & Veatch utilized the PROMOD model results to analyze the projected regional air quality and emissions impacts from power generation from the proposed ANE pipeline project. As shown in Schedule GJW-4, comparing the With ANE Only case to the Reference Case finds an approximately 16% reduction in NOx, a 26% reduction in SOx, and a 0.86% reduction in GHG emissions from the power sector for the New England region over the analysis period. The testimony of Mr. Andrew C. Byers (Schedule ACB-1) offers additional details regarding the environmental impacts of the ANE Project.

Overall, Black & Veatch believes that the ANE pipeline can have a positive impact in improving regional air quality and reducing greenhouse gas emissions from the power

generation sector. Gas-fired generation can play an important role in renewable integration, and the ANE pipeline can provide natural gas at a no-notice firm transportation rate to generation units across the region.

Compared to Sensitivity Reference Case A, the ANE pipeline is projected to have a similar regional impact, reducing NOx by 14%, SOx by 58%, and GHG by 0.25% over the analysis period. Air emissions are relatively unchanged by the ANE project compared to Sensitivity Reference Case B.

III. Conclusion

Q. Does this conclude your pre-filed testimony in this proceeding?

A. Yes. It does.

Schedule GJW-1
Long-Term Economic Benefits

Schedule GJW – 1 - Summary Table of Long-term Economic Benefits and Costs to New England Electric Consumers

Project Cost-Benefits Summary 2019-2038 ($ Billions)							
	Levelized			Present Value			
Project	Annual Benefits	Annual Costs	Annual Net Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Reference Case - With ANE Only	[redacted]		$1.1	[redacted]		$10.2	[redacted]
Sensitivity Reference Case A - With ANE			$0.4			$3.5	
Sensitivity Reference Case B - With ANE			$0.4			$3.5	
Reference Case - With GDF Suez			$0.6			$4.9	
Reference Case - With Repsol			$0.2			$2.1	

Schedule GJW-2
Regional Emissions
Impact of ANE

Schedule GJW – 2- Regional Emissions Impact of ANE

TOTAL POLLUTANT EMISSIONS 2019-2038			
Scenarios	**NO_X (Thousand Tons)**	**SO_2 Thousand Tons)**	**Greenhouse Gases (Million Tons $CO_{2)}$**
Reference Case	[redacted]		
Reference Case - With ANE Only			
Sensitivity Reference Case A			
Sensitivity Reference Case A – With ANE			
Sensitivity Reference Case B			
Sensitivity Reference Case B – With ANE			

Schedule GJW-3
Black & Veatch Rept.

Evaluation of Long-term Economic Benefits from Proposed Incremental Energy Infrastructure into New England

PREPARED FOR

The Narragansett Electric Company d/b/a National Grid ("National Grid")

JUNE 2016

BLACK & VEATCH
Building a world of difference.

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BLACK & VEATCH STATEMENT

This report was prepared for National Grid ("Client") by Black & Veatch Management Consulting, LLC ("Black & Veatch") and is based in part on information not within the control of Black & Veatch. As such, Black & Veatch has not made an analysis, verified, or rendered an independent judgment of the validity of the information provided by others, and, therefore, Black & Veatch does not guarantee the accuracy thereof.

In conducting our analysis, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilize in performing the analysis and making these projections follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.

Readers of this report are advised that any projected or forecast price levels and price impacts, reflects the reasonable judgment of Black & Veatch at the time of the preparation of such information and is based on a number of factors and circumstances beyond our control. Accordingly, Black & Veatch makes no assurances that the projections or forecasts will be consistent with actual results or performance. To better reflect more current trends and reduce the chance of forecast error, we recommend that periodic updates of the forecasts contained in this report be conducted so more recent historical trends can be recognized and taken into account.

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Glossary of Terms

AIM	Algonquin Incremental Market. Spectra Energy's expansion project on the Algonquin Pipeline System in New England.
ANE	Algonquin Access Northeast
AGT	Algonquin Gas Transmission Pipeline
Bcf	One billion cubic feet. In the context of LNG, the gas-to-liquid equivalency is approximately 1 Bcf (gas) = 17,200 tonnes (liquid).
Bcf/d	One billion cubic feet per day.
CAGR	Compounded Annual Growth Rate
CPP	Clean Power Plan. US Environmental Protection Agency's proposed carbon reduction plan.
EDC	Electric Distribution Company
EIA	U.S Department of Energy **-** Energy Information Administration.
EMP	Energy Market Perspective. Black & Veatch's subscription-based, bi-annual comprehensive outlook of natural gas and power markets in North America.
EPA	Environmental Protection Agency
Firm LDC Load	Contractual gas demand on the gas utility local distribution system that must be met with its gas transportation and supply portfolio
GHG	Greenhouse Gas
GPCM	Gas Pipeline Competition Model. A third-party proprietary model Black & Veatch uses for natural gas market forecasting.
HDD	Heating Degree Days
IMM	Integrated Market Modeling
ISO-NE	ISO-New England
NESCOE	New England States Committee on Electricity
LDC	Local Distribution Company
LMP	Locational Marginal Prices
LNG	Liquefied natural gas.
MMcf/d	One million cubic feet per day.

MMBtu	One million British Thermal Units. 1 MMBtu = 1 Dekatherm (Dth).
MMBtu/d	One million British Thermal Units per day
MW	Megawatt
MWh	Megawatt-hour
M&NP	Maritimes & Northeast Pipeline
NPV	Net Present Value
PNGTS	Portland Natural Gas Transmission System
RFP	Request for Proposal
SOEP	Sable Offshore Energy Project
TGP	Tennessee Gas Pipeline

1.0 Executive Summary

On October 23, 2015, The Narragansett Electric Company d/b/a National Grid ("National Grid") issued a Request for Proposal ("RFP") for natural gas pipeline capacity, liquefied natural gas ("LNG"), and natural gas storage. Black & Veatch was retained by National Grid to provide an independent evaluation of the long-term economic benefits to electric consumers from eligible responses that satisfied the RFP requirements. Based on Black & Veatch's review of the RFP, two responses satisfied the key requirements of the RFP.[1] Algonquin Gas Transmission Company's Access Northeast ("ANE") and Tennessee Gas Pipeline Company's Northeast Energy Direct ("NED") projects were determined to be eligible for further economic benefit analysis. On April 20, 2016, the NED project was cancelled by Tennessee Gas Pipeline Company and was then eliminated from further economic benefit analysis.

As directed under Rhode Island's Affordable Clean Energy Security Act, National Grid consulted with Office of Energy Resources and the Division of Public Utilities and Carriers regarding the procurement of natural gas capacity. As a result of that consultation, , Black & Veatch conducted additional analysis of the economic benefits of the RFP responses by Repsol ("Repsol") and GDF Suez ("GDF Suez"). In addition, Black & Veatch developed two sensitivity reference cases that reflected potential incremental resources that might be procured under the New England Clean Energy RFP, and Black & Veatch evaluated the ANE pipeline project against those sensitivity reference cases.

Black & Veatch's assessment methodology is built upon our industry expertise in the North American gas and power markets and our experience in fundamental analysis of natural gas supply, demand, and the interconnecting interstate pipeline grid. Having served the power industry for nearly a century, Black & Veatch has hands-on experience analyzing key drivers of natural gas demand growth from the power sector such as the relative capital cost of power generation technologies, impact of the Clean Power Plan ("CPP"), nuclear permitting, U.S. Environmental Protection Agency ("EPA") rules, and renewable targets. With oil and gas shale plays emerging as the primary supply source to the U.S. market, we continually monitor their development and undertake in-depth analyses to understand North American natural gas supply potential. In addition, Black & Veatch conducted analyses in New England as part of the New England State Committee on Electricity's ("NESCOE") study to evaluate short-term and long-term energy infrastructure solutions in the region.

Black & Veatch produces an integrated and comprehensive outlook on North American energy issues in our biannual Energy Market Perspective ("EMP") that incorporates our power market expertise with our views on generating fuels such as natural gas and coal. The Reference Case assumptions and analysis in this report are based on our 2016 EMP and summarize our views on key power and natural gas market fundamental drivers that influence our projections of natural gas supply, demand, and prices across North America. Black & Veatch utilized RBAC, Inc.'s GPCM™ model to assess the natural gas price impact of

[1] See the testimony of Richard Porter of Black & Veatch on behalf of National Grid before the Rhode Island Public Utilities Commission.

the proposed projects and the ABB/Ventyx PROMOD IV model to analyze the corresponding impact on the electric market prices in New England.

Key Observations and Analysis Results

The development of ANE can provide $1.1 Billion in levelized annual net benefits to New England energy consumers.

The combination of firm LDC load growth and the region's growing dependency on gas-fired generation will require the development of additional gas pipeline capacity. The ANE project will have a significant impact on lowering regional winter natural gas and electric prices and provide significant long-term economic net benefits.

The GDF SUEZ and Repsol LNG projects generate lower levels of annual benefits to electric consumers and have lower benefit-to-cost ratios when compared to ANE on a standalone basis.

Both LNG import projects with assumed additional pipeline capacity commitments on Tennessee and Algonquin are projected to reduce natural gas and electric prices for the region during winter periods, and provide long-term economic net benefits. The GDF Suez LNG import project is projected to generate $0.6 Billion in levelized annual net benefits while the Repsol Canaport LNG import project is projected to yield $0.2 Billion in levelized annual net benefits.

The ANE project generates significant annual net benefits to New England energy consumers under various sensitivity reference cases with additional large-scale clean energy generation and transmission sources.

The substantial net benefits projected from ANE when measured against sensitivity reference cases that assume substantial incremental clean energy generation and associated transmission. When compared to those sensitivity reference cases, ANE is projected to generate approximately $0.4 Billion in levelized annual net benefits. The sensitivity reference cases assume additional renewable energy and transmission is placed into service by 2019 and 2020, with the goal of providing New England with additional clean energy alternatives.

ANE generates regional environmental benefits resulting from the reduction of SOx, NOx, and GHG emissions

The ANE pipeline project is projected to reduce regional air emissions from power generation. Compared to the Reference Case, the With ANE scenario is projected to lower New England region air emissions by approximately 15% for NOx, 25% for SOx, and 0.85% for greenhouse gases ("GHG") over the analysis period.

2.0 Reference Case Methodology and Assumptions

Overview of Black & Veatch Integrated Model Approach

Black & Veatch utilized an Integrated Market Modeling ("IMM") process to generate wholesale market prices for natural gas, and wholesale Locational Marginal Prices ("LMP") at key New England transmission zones. GPCM™ was used to model the New England natural gas market, while PROMOD was used to model the ISO-NE electric market. Model runs were executed in an iterative fashion to ensure consistent results, as illustrated in Figure 1.

Black & Veatch used this IMM process to estimate the price impact of proposed natural gas infrastructure solutions on the New England energy market. As modeled, natural gas infrastructure constraints result in acute natural gas price increases during winter months, which are then reflected in the assumptions of the electric market model, leading to increased electric prices. Proposed natural gas infrastructure will alleviate constraints and diminish natural gas price increases during winter months.

The IMM process involves detailed market projections across the North American energy market to take into account any market activity that could affect New England. For example, high growth in demand across North America could increase the cost of New England supplies or even divert supplies away from New England.

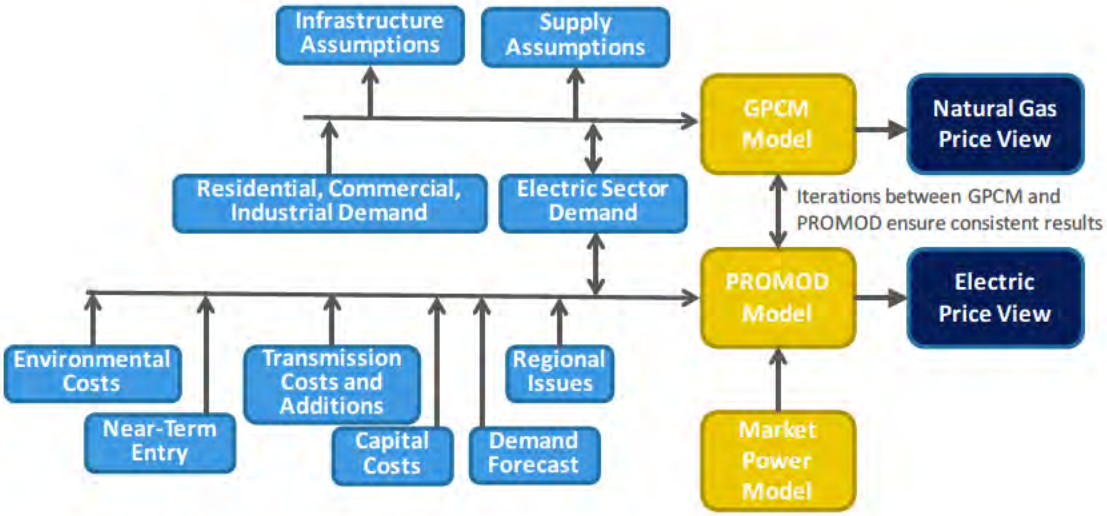


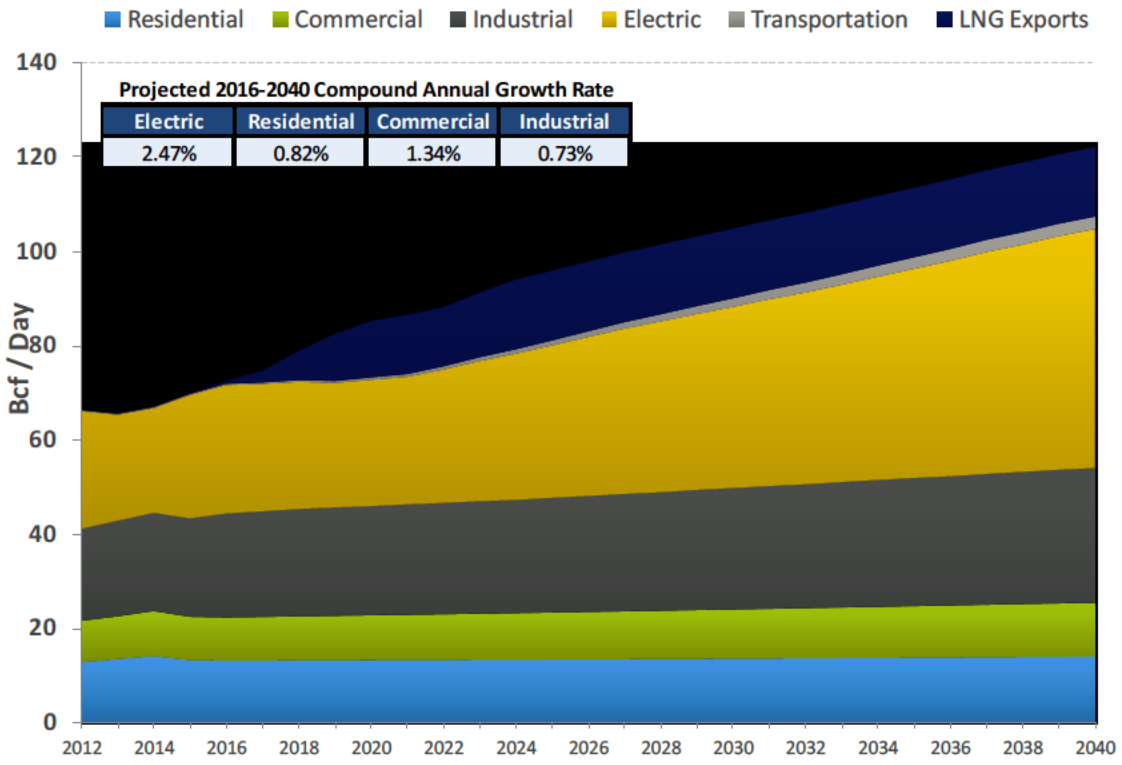
Figure 1 Integrated Market Modeling Process

Black & Veatch's analysis draws upon those assumptions utilized in the 2016 Energy Market Perspective regarding future natural gas and power infrastructure, pricing, and the outlook on other power fuels. The EMP is an integrated outlook, updated biannually, that assesses the direction of the natural gas, power, coal, and emissions markets. The *Reference Case* incorporates the EPA's Clean Power Plan as the primary driver for gas demand growth in the power generation sector.

Key Natural Gas Demand Assumptions

Black & Veatch expects demand for natural gas in the Lower 48 to grow from 72 Bcf/d to 122 Bcf/d over the forecast period from 2016 through 2040, an average growth rate of 2.1% per annum, as shown in Figure 2. This growth is largely driven by the increased demand for natural gas-fired power generation, with moderate growth in LNG exports and industrial demand.

Figure 2: Historical and Projected Lower 48 Natural Gas Demand 2012-2040



Power generation is expected to be the main driver of demand growth in the North American natural gas market. In August 2015, the EPA finalized the CPP with the overall objective to achieve a cumulative, nationwide reduction of GHG emissions of 32 percent below 2005 emission levels by 2030.

Based on the major building blocks of the CPP, Black & Veatch believes that natural gas-fired generation is positioned to play a critical role in lowering emission levels as well as mitigating renewable capacity intermittency. Black & Veatch projections indicate that the share of natural gas in providing energy for the U.S. is expected to increase by approximately 30% between 2016 and 2040.

Overall, Black & Veatch anticipates a slight recovery of industrial demand from the past few years as the economy continues to recover from the 2008-2010 recession. As U.S. oil and gas prices remains relatively inexpensive compared to alternative fuels and relative to other regions in the world, industrial demand is expected to experience moderate growth over the long term. Overall U.S. residential and commercial demand is expected to remain flat as

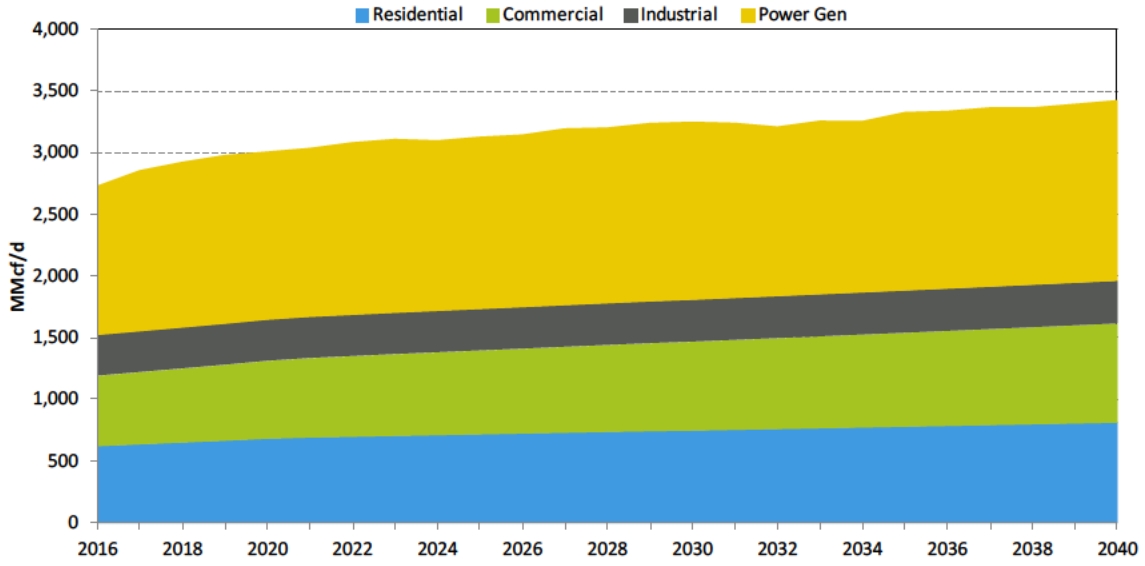
demand growth due to population and economic growth are offset by energy efficiency gains.

New England Natural Gas Demand Assumptions

Figure 3 below shows the historical and projected demand for natural gas in New England. Compared to other U.S. regions, New England is expected to experience moderate demand growth in the residential and commercial sectors. Demand from the residential sector is expected to grow at 1.1% per year while demand from the commercial sector is expected to grow at 1.4% per year. State conversion initiatives and the low gas price environment will support residential and commercial customer growth. Industrial gas demand is expected be relatively flat and remain at current historical levels.

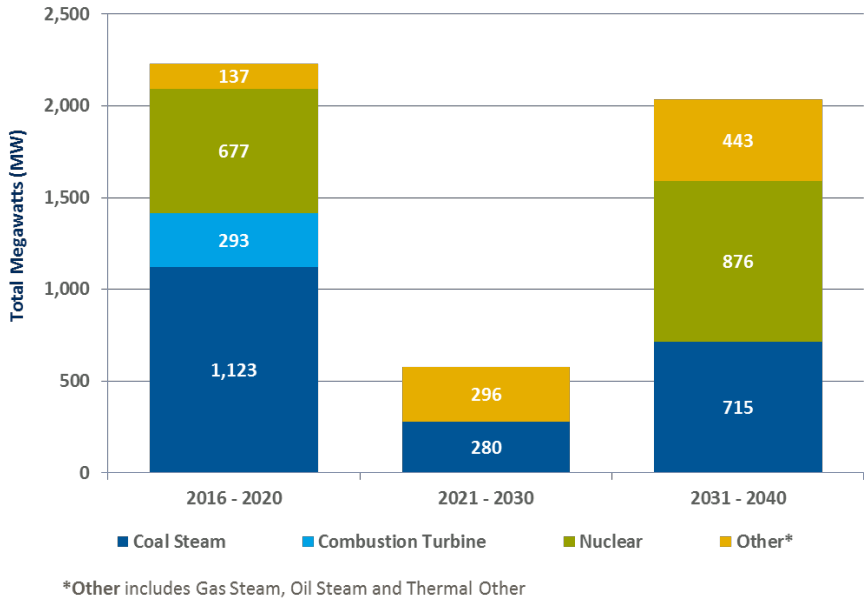
The retirement of the Pilgrim nuclear facility and Brayton Point over the next several years is expected to increase the region's dependency on natural gas for power generation. New gas-fired generation facilities like Salem Harbor and CVP Towantic Energy Center will also increase gas demand for power generation in 2017 and 2018, respectively. The potential impact of the CPP is also expected to increase gas demand in the region. Overall, gas demand for power generation is assumed to grow at 0.8% per year over the analysis period.

Figure 3: Projected New England Natural Gas Demand 2016-2040



Black & Veatch's assumptions in regards to announced and projected retirements in New England are shown in Figure 4. In the initial 2016-2020 period, over 1,100 MW of coal steam capacity at Brayton Point is expected to be retired, along with 293 MW of combustion turbine oil units across various plants in New England. From 2021-2030, additional economically driven capacity retirements of older coal, and oil and gas stream turbine units total approximately 576 MW. After 2030, Black & Veatch is projecting the retirement of the Millstone nuclear unit, as well as an additional 715 MW of coal stream capacity retirement across the region.

Figure 4: Announced and Projected ISO-NE Capacity Retirements



*Other includes Gas Steam, Oil Steam and Thermal Other

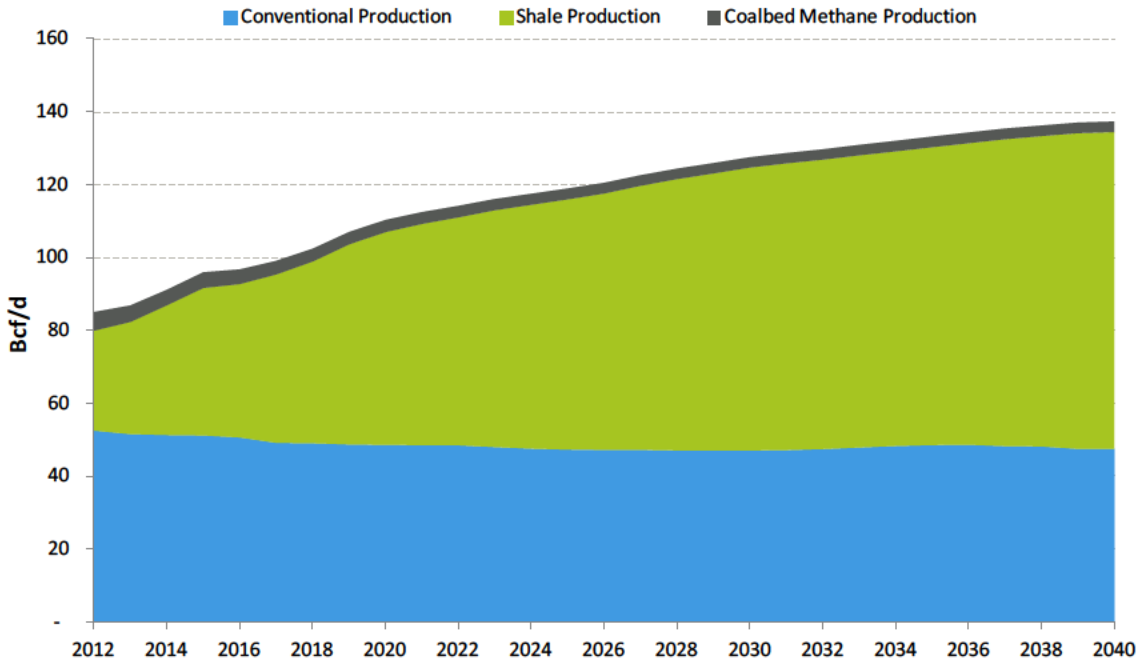
To replace the economically driven capacity retirements across ISO-NE, Black & Veatch assumed generic combined cycle units to be constructed at various locations across New England over the latter half of the analysis period. Gas-fired combined cycle units were the most economically viable option and were assumed to be constructed across ISO-NE zones at locations with reasonable access to future gas supply and transportation capacity.

Key Natural Gas Supply Assumptions

Black & Veatch utilizes a basin-by-basin, play-by-play approach to assess the productive capacity, availability, and cost of major natural gas supply sources in North America. For the major shale plays that will contribute to the majority of natural gas production growth, Black & Veatch utilizes in-house geoscientists and geologists to assess the resource base, technology trends in drilling, and natural gas liquids content. Black & Veatch also monitors trends in finding and development costs, well type curves, estimated ultimate recoveries, and tax and policy changes in order to assess the relative production costs across all production areas that will determine the dynamics of production growth based on competitive cost advantages.

Black & Veatch projects that North American natural gas production will grow from 97 Bcf/d to 138 Bcf/d, at a growth rate of 1.5% per annum from 2016 to 2040, as shown in Figure 5. Shale gas production is expected to continue to grow from 40 Bcf/d to close to 87 Bcf/d by 2040. Black & Veatch expects the Marcellus and Utica Shale plays to continue to grow from 18 Bcf/d in 2016 to 39 Bcf/d by 2040.

Figure 5: Historical and Projected North American Production 2012-2040



Eastern Canadian Supply Assumptions

Eastern Canadian production was an important supply source delivering to New England via the Maritimes and Northeast ("M&NE") pipeline starting in 1999, with Sable Island Offshore Energy Project ("SOEP") production. However, SOEP production has been in sharp decline and is expected to cease production by 2018. Deep Panuke production was expected to offset some of these declines, but has reached peak production in 2014, despite only starting production in 2013. The continued decline in Eastern Canadian production coupled with Nova Scotia and New Brunswick consumption will further limit M&NE pipeline imports to New England.

LNG Import Assumptions

Black & Veatch expects the Distrigas terminal in Everett, Massachusetts, to continue to receive LNG cargoes similar to recent historic levels. Over the analysis period, our analysis assumed an average annual sendout at the terminal to be approximately 150 MMcf/d with peak winter sendout of approximately 250 MMcf/d, similar to the observed volumes during the 2014-2015 winter season.

Supplies received at the Canaport LNG terminal (Saint John, New Brunswick) are expected to decline relative to historical norms as no new firm supplier has emerged since the firm supply agreement with Qatar expired in 2013. Thereafter, imports at Canaport will be expected to be driven by arbitrage opportunities based on spot price expectations. Black & Veatch does not expect significant LNG import volumes at Canaport, Neptune, or Northeast Gateway beyond 2017.

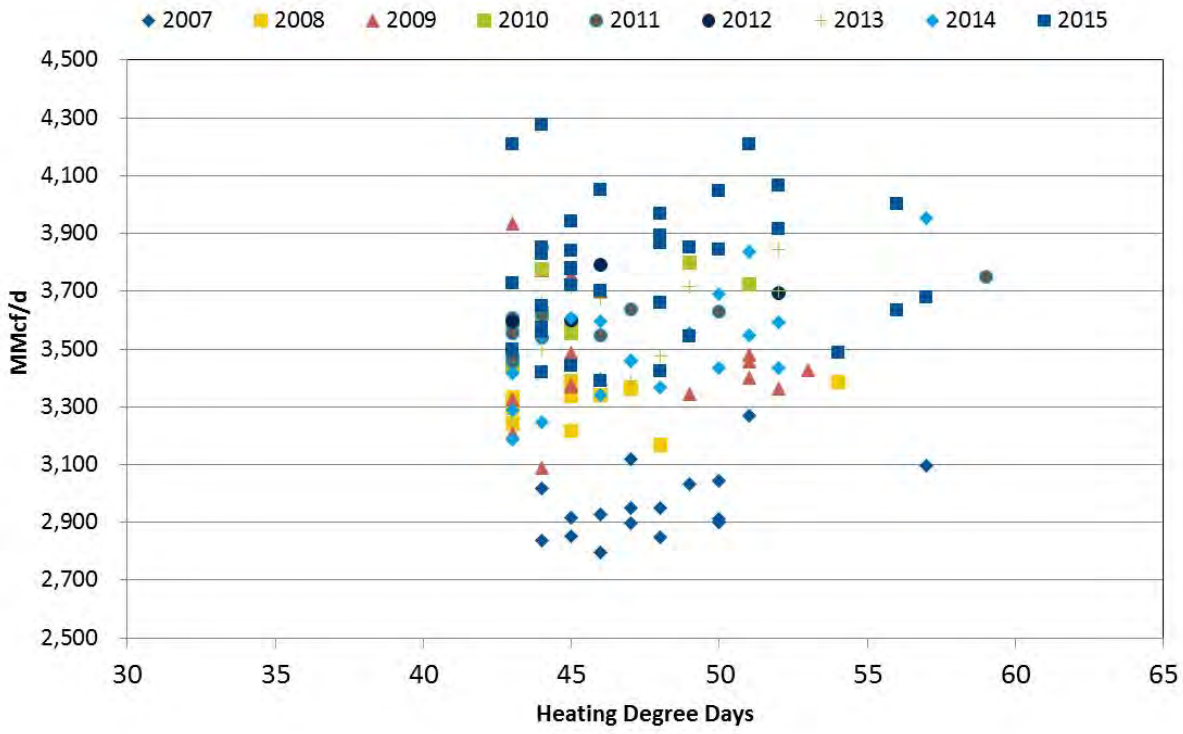
New England Winter Peak Day Growth

Black & Veatch has projected compound annual average natural gas demand growth for New England to be 0.95% over the 25 year analysis period, which would typically translate to comparable peak and design day consumption growth. However, in New England, peak day demand may be growing at a quicker pace.

Black & Veatch utilized interstate pipeline electronic bulletin board data to estimate the total daily deliveries to all consumer types in New England and the daily weather data at Boston's Logan International Airport to understand the relationship between gas consumption and weather. Our analysis focused on the coldest days of the winter periods (>90th percentile of a historical 30 year distribution) which equated to 42 Heating Degree Days ("HDD") or 23° Fahrenheit.

Figure 6 below shows the interstate gas pipeline deliveries on the coldest days in New England since 2007. Over the past 9 years, daily gas consumption has steadily grown over comparable levels of HDDs. For example, in 2007, on a day where the average temperature only reached 21° Fahrenheit (44 HDDs), total gas consumption reached approximately 2,800 MMcf/d. For the same temperature levels in 2015, the estimated gas consumption reached approximately 4,200 MMcf/d. The difference can in part be attributed to differences in the timing of each occurrence during the winter season and the utilization of LNG peakshaving, but significant peak day demand growth remains.

Figure 6: Historical New England Pipeline Deliveries on the Coldest Days of the Year

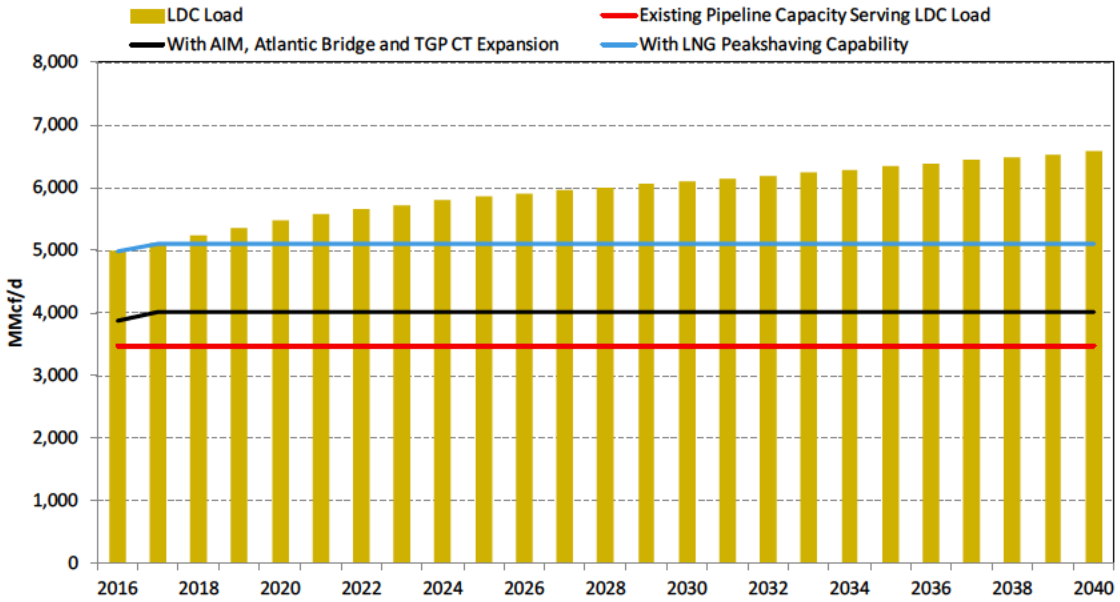


Gas consumption growth on peak and design day weather conditions is an important consideration to determining the need for interstate pipeline capacity or LNG peakshaving

deliverability. Based on our understanding of annual average and peak day demand growth, Black & Veatch developed a projection of firm New England local distribution gas load under design day weather conditions. As shown in Figure 7 below, the LDC design day demand is expected to exceed 5,500 MMcf/d by 2020 and reach 6,000 MMcf/d by 2030. To meet design day conditions, LDCs can utilize interstate pipeline capacity or LNG peakshaving deliverability.

Black & Veatch estimates that New England LDCs hold approximately 3,500 MMcf/d of interstate capacity that brings gas supply into the region and close to 1,100 MMcf/d in LNG peakshaving deliverability. Spectra's AIM and Tennessee Gas Pipeline's ("TGP") Connecticut Expansion are expected to be placed into service by winter 2016, followed by Spectra's Atlantic Bridge expansion in 2017, which will add a total of 547 MMcf/d of capacity to the region, as shown in Figure 7. Without any further pipeline capacity additions, New England LDCs will need approximately 380 MMcf/d by 2020 and 1,230 MMcf/d by 2035 to serve firm loads on their distribution systems under design day conditions.

Figure 7: Projected New England Firm Local Distribution Company Design Day Growth



New England LDC demand growth combined with the region's increasing dependency on gas-fired generation will require additional interstate gas pipeline capacity during peak winter periods. Historically, New England LDCs have contracted for pipeline capacity or storage deliverability needs on an as-needed basis. In the Reference Case, Black & Veatch assumed that LDCs would be able to contract immediately for incremental capacity as-needed through the analysis period. Additional generic pipeline capacity additions to serve New England LDCs were added prior to the start of the winter season. This would isolate for the most part the impact of the various proposed infrastructure projects on reducing regional constraints to serve power generation and the price impact on natural gas and electric markets.

3.0 Pipeline Scenario Assumptions

Based Black & Veatch's review of National Grid's RFP for interstate capacity/gas supplies, only the responses related to ANE and NED satisfied the key requirements of the RFP. Because the NED project was subsequently cancelled, Black & Veatch evaluated the long-term economic benefits of the ANE pipeline described in Table 1 below:

Table 1: Summary Description of Scenarios

PROJECT DETAIL	WITH ANE ONLY
Capacity (MDQ)	Phase I – [redacted] Dth/d Phase II – [redacted] Dth/d Phase III – [redacted] Dth/d Phase IV – 900,000 Dth/d
In-Service Date	Phase I – [redacted] Phase II – [redacted] Phase III – [redacted] Phase IV – May 2021
Primary Receipt Point	Phase I – [redacted] Phase II – [redacted] Phase III – [redacted] Phase IV – Ramapo, Mahwah, Brookfield and Acushnet
Primary Delivery Zones	Based on Aggregation Areas (AA) and timing defined in the [redacted]
LNG Storage	6.8 Bcf LNG Storage Capacity Max Liquefaction: 54,000 Mcf /d Max Vaporization: 400,000 Mcf/d
LDC Capacity	LDC Generic Expansion as needed
EDC Capacity	900,000 Dth/d

Algonquin Access Northeast Project

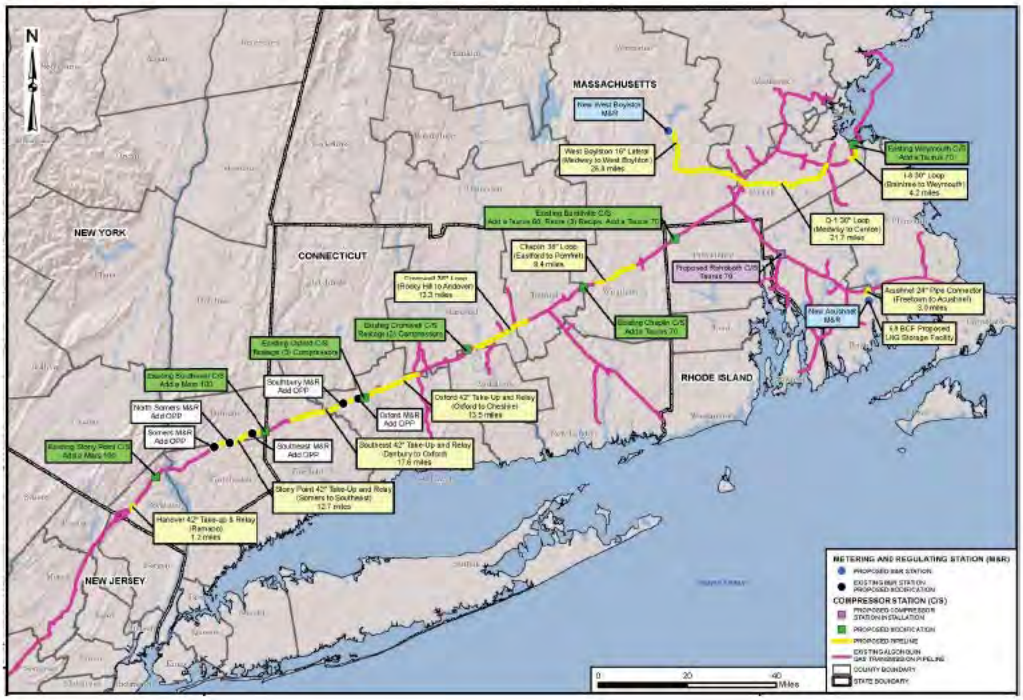
As shown in Figure 8 below, the ANE extends from northern New Jersey to eastern Maine, utilizing a combination of pipeline capacity and LNG storage to deliver up to 900,000 Dth/d

across New England. The project has four phases and is expected to be phased in over the Nov-2018 through May-2021 time frame. While the ANE project utilizes existing Algonquin Pipeline right-of-way, it will require an upgrade or construction of [redacted] miles of various pipeline facilities, modifications at [redacted] compressor stations, and a [redacted].

The ANE project will have firm receipt points at Mahwah, NJ, with TGP, Ramapo, NY, with Millennium Pipeline and Brookfield, CT, with Iroquois Pipeline, while the 6.8 Bcf LNG storage facilities will be located at Acushnet, MA. ANE will also offer secondary firm receipt points with Texas Eastern, Columbia Gas, and [redacted] dity at [redacted].

Based on Black & Veatch's With ANE Only scenario, EDCs will contract for 900,000 Dth/d with deliverability to power generators based on Aggregation Areas established in the RFP.

Figure 8: Proposed Algonquin Access Northeast Project



2 Algonquin ANE RFP Response Page C-7 to C-8 Figure 9 and 10.

4.0 LNG Import Scenario Assumptions

None of the LNG solutions offered in response to National Grid's RFP met the key requirements of the RFP, according to Black & Veatch's evaluation of them. Nonetheless, as a result of National Grid's consultation with the Office of Energy Resources and the Division of Public Utilities and Carriers, Black & Veatch analyzed two additional LNG scenarios and evaluated the long-term economic benefits of each. Black & Veatch developed the assumptions in Table 2 below, regarding the primary firm deliverability of the LNG proposals to power generators for the purpose of this analysis.

Table 2: Summary Description of LNG Scenarios

PROJECT DETAIL	WITH GDF SUEZ	WITH REPSOL
Description of Service	[redacted]	
Maximum Daily Quantity (MMBtu/d) and Annual Contract Quantity (MMBtu)	[redacted]	
Service Start Date	[redacted]	[redacted]
Initial Delivery Point of Regasified LNG	Boston Gas Company d/b/a National Grid Algonquin Gas Transmission and Tennessee Gas Transmission Constellation Mystic Power, LLC	Outlet of Canaport facility to M&NP
Primary Firm Deliverability to Power Generation	Existing GSGNA contract with AGT [redacted] and TGP [redacted]. Assumes renewal of current contracted capacity on AGT and TGP[3]	Use existing M&NE contract capacity 730,000 Dth/d to serve Verso Bucksport Plant, Westbrook Energy Center, Newington Energy and Maine Independence [redacted]

[3] Black & Veatch omitted an existing GSGNA with AGT for 60,000 Dth/d due to limited ROFR rights

Additional Primary Firm Capacity Assumption	[redacted] on AGT and [redacted] on TGP to backhaul from Distrigas Terminal to interconnected ISO-NE generators on each pipeline	[redacted] on AGT to backhaul from Beverly and [redacted] on TGP[4] to backhaul from Dracut to interconnected ISO-NE generators on each pipeline
LDC Capacity	LDC Generic Expansion as needed	LDC Generic Expansion as needed
EDC Capacity	[redacted] plus [redacted] on TGP for primary firm deliverability	[redacted] on AGT and [redacted] for primary firm deliverability

GDF Suez – Everett LNG Import Terminal

GDF Suez proposes to deliver additional regasified LNG to Tennessee and Algonquin to serve gas-fired generation in ISO-NE. Utilizing ENGIE's diverse portfolio of long-term LNG supply of over 750 Bcf/year, and fleet of 14 LNG vessels, GDF Suez is offering a number of peak day natural gas supply services to the New England market. Black & Veatch chose to analyze the [redacted] which provides [redacted]

GDF Suez is currently capable of providing primary firm deliverability from the Everett terminal utilizing existing firm capacity on AGT and TGP. On AGT, GDF Suez has 230,000 Dth/d of firm transportation capacity, of which [redacted] is assumed to be renewed over the analysis period. On TGP, GDF Suez has [redacted] of firm transportation capacity and is assumed to be renewed as well.

In the past, the Everett terminal has been able to transport regasified LNG on TGP and AGT exclusively on a backhaul basis.[5] Black & Veatch assumed that GDF Suez would not be able to provide primary firm deliverability to power generators beyond their existing firm transportation capacity agreements on AGT and TGP. While backhaul opportunities may exist on TGP and AGT during the winter season, these opportunities are dependent on forward haul flows and other pipeline considerations that could restrict the deliverability of theses volumes to power generators on a primary firm basis. To move [redacted]

[4] The TGP/AGT [redacted] split based on MW interconnected on TGP and AGT as stated in the RFP

[5] GDF SUEZ RFP Response Page 5

from the Everett terminal on a primary firm capacity basis, GDF Suez would need an additional [redacted] of additional firm capacity on AGT and TGP.

Repsol – Canaport LNG Import Terminal

Repsol proposes to deliver [redacted] and up to [redacted] annually of regasified LNG from the outlet of Canaport LNG facility via M&NP to TGP at Dracut, MA, and AGT at Beverly, MA. Repsol has 730,000 MMBtu/d of firm capacity on M&NP and can utilize this capacity to supply gas on a primary firm basis to several power generation units in Maine and New Hampshire. Black & Veatch assumed that the Repsol supplies would be delivered over a [redacted] period during the months of January and February.

Similar to the GDF Suez LNG import solution, Black & Veatch assumed that Repsol would renew the existing M&NP pipeline capacity, and be able to directly serve the Maine Independence plant, Verso Bucksport LLC plant, Westbrook Energy Center, and the Newington Energy plant. In addition to existing M&NP capacity, Black & Veatch assumed that an additional [redacted] of capacity would be needed to deliver gas supplies on a primary firm basis to gas fired generators on TGP and AGT downstream of Dracut and Beverly, respectively.

[6] Per GDF Suez RFP response pg 6

5.0 Sensitivity Reference Case Assumptions

Subsequent to National Grid's consultation with the Office of Energy Resources and the Division of Public Utilities and Carriers, Black & Veatch evaluated the ANE pipeline project against two sensitivity reference cases. These sensitivity reference cases build upon the assumptions in the original Reference Case by adding incremental renewable energy projects that could result from the New England Clean Energy RFP.

Table 3: Summary Description of Sensitivity Reference Cases

PROJECT DETAIL	SENSITIVITY REFERENCE CASE A – RENEWABLE HYDRO IMPORTS	SENSITIVITY REFERENCE CASE B – RENEWABLE HYDRO IMPORTS PLUS WIND GENERATION
In-Service Date	January 2019	January 2020
Project Description	Renewable hydroelectricity imports from Québec to Deerfield, New Hampshire	Incremental Wind Generation and transmission in Maine
Project Capacity	Approximately 1,090 MW capacity with new 320-kv high voltage transmission from Québec to Deerfield, NH	Approximately 1,200 MW Capacity with new 345 kV transmission line to Keene Road Substation in Chester, Maine
Assumed Delivery Commitment	6.3 TWh per year over the 20 year analysis period	Delivery Profile based on existing Main Wind Renewable Generation

Renewable Hydro Imports with Transmission

In Sensitivity Reference Case A, Black & Veatch assumed that 1,090 MW of hydropower produced in Quebec would be delivered via a new 320-kv high voltage transmission line to Deerfield, New Hampshire, starting in 2019. Over the twenty year analysis period, it is assumed that the proposed project would be able to deliver approximately 6.3 TWh per year. From Deerfield, the proposed HVDC transmission line would be linked to a 345-kV alternating current line via an HVDC/AC converter terminal located in Franklin, New Hampshire.

Renewable Maine Wind Generation with Transmission

In Sensitivity Reference Case B, in addition to the Renewable Hydro Import project, Black & Veatch assumed additional renewable Maine wind generation and transmission would be developed by 2020. In total, Black & Veatch assumed that approximately 1,200 MW of wind generation would be developed in Maine, and sufficient transmission capacity to deliver into the Keene Road substation in Chester, Maine. Black & Veatch assumed that these 1,200

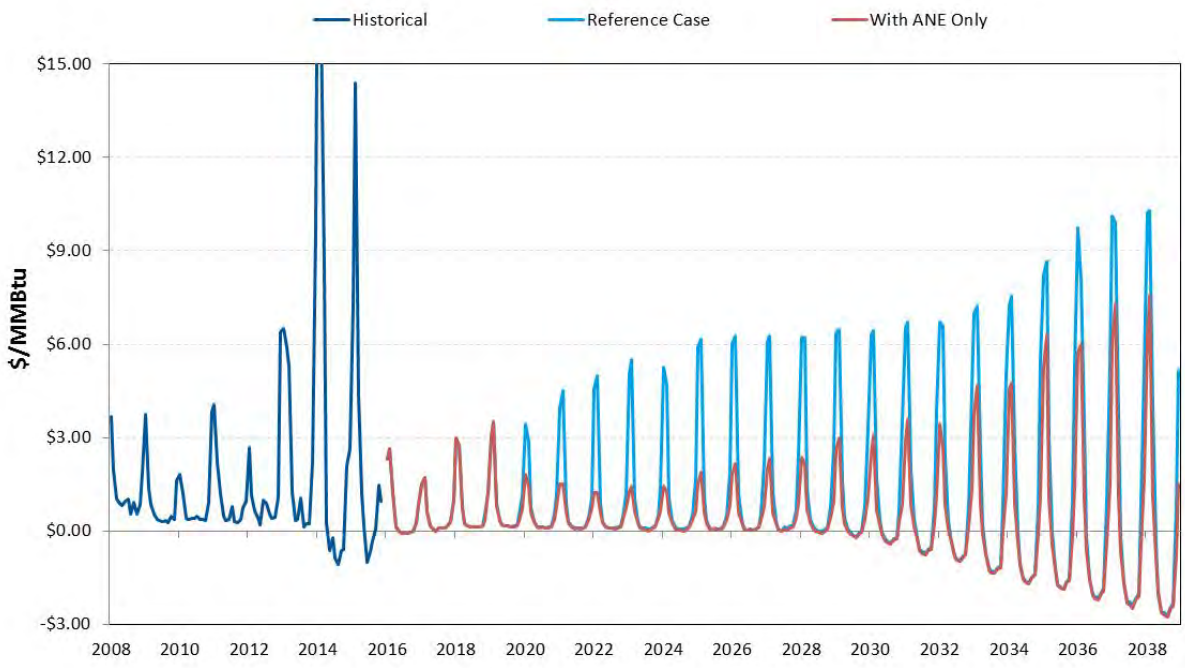
MW of new wind generating capacity would be incremental to the renewable generation included in the Reference Case to fulfill regional RPS requirements. As such, Sensitivity Reference Case B assumes over-compliance with RPS requirements.

6.0 Natural Gas and Electric Price Impacts – With ANE Scenario

Black & Veatch's Integrated Market Modeling process was applied to the assumptions described in Section 2.0 to develop monthly natural gas and electricity price forecasts. The Reference Case price projections were used as benchmarks when quantifying the benefits of the proposed pipeline.

As seen in Figure 9, the Reference Case projections indicate that, after the projected in-service of Spectra's AIM and TGP Connecticut expansion, the Algonquin city-gates basis will continue to rise during winter months if no additional infrastructure is constructed to serve gas demand for power generation.

Figure 9: Projected Natural Gas Basis Impact across Pipeline Scenarios – Algonquin, city-gates



The Algonquin city-gates basis is projected to moderate relative to the extremes experienced in the past two winter seasons[7], but continue to rise above $3.00/MMBtu on a monthly average basis starting in 2019. By 2025, the monthly average basis will exceed $6.00/MMBtu which would typically translate to daily basis blowouts in the $20-30/MMBtu during that same month; similar to what was experienced in the 2012-2013 winter season.

Additional pipeline capacity into the market from the ANE project is expected to reduce Algonquin city-gates basis and reduce daily price volatility during the winter months. The ANE project has a significant impact in reducing winter basis throughout the analysis period. Table 4 below compares the impact on winter Algonquin city-gates basis between the Reference Case and the With ANE Only scenario.

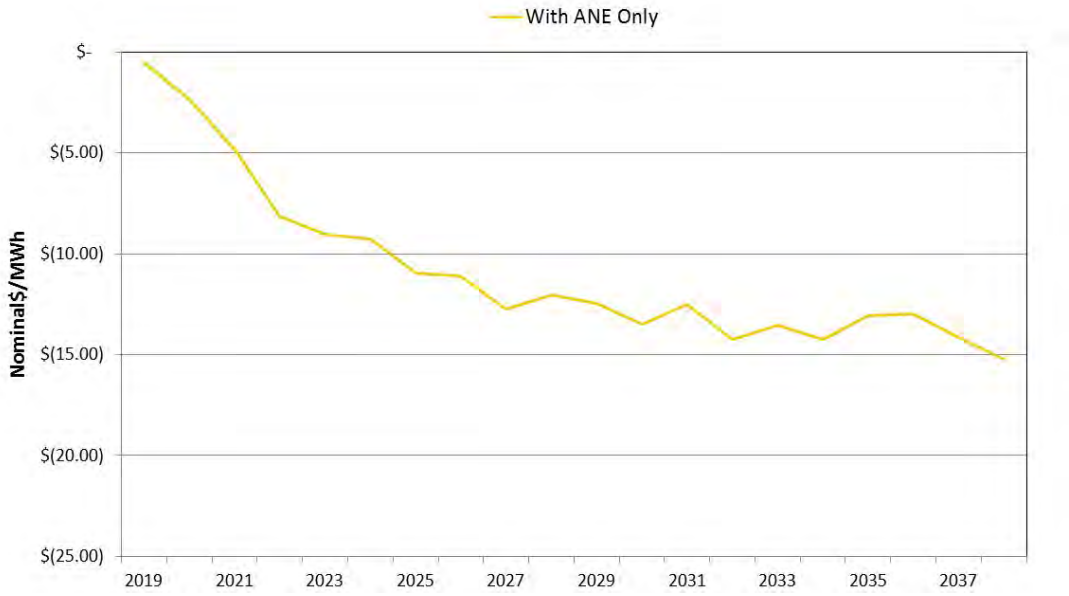
[7] Algonquin city-gates basis reached $70/MMBtu in January 2014 and $26/MMBtu in February 2015.

Table 4: Summary Algonquin city-gates Average Monthly Winter (Dec-Feb) Basis Impact - Pipeline Scenario

	Algonquin City Gates ($/MMBtu)			
	2019 - 2028		2029-2038	
	Average Monthly Winter (Dec-Feb) Basis	Differential to Reference Case	Average Monthly Winter (Dec-Feb) Basis	Differential to Reference Case
Reference Case	$ 4.07		$ 6.79	
With ANE Only	$ 1.57	$ (2.50)	$ 3.55	$ (3.24)

The increased dependency on natural gas-fired generation in New England has tied regional power generation prices to wholesale natural gas prices. The reductions in regional natural gas prices during the peak winter periods, as seen in Table 4 translate to lower regional electric prices. In Figure 10, the average annual electric price reduction over the twenty year analysis period with the ANE project was $10.85/MWh.

Figure 10: Projected Electric Market Price Impact across ANE Pipeline Scenario – New England Weighted Average Price (Nominal$/MWh)



7.0 Natural Gas and Electric Price Impacts – LNG Import Scenarios

Additional LNG import volumes into the New England market are also expected to reduce Algonquin city-gates basis and reduce daily price volatility during the winter months. As with the ANE pipeline scenario, the Reference Case price projections were used as benchmarks when quantifying the benefits of the LNG import solutions.

The GDF Suez LNG proposal has a slightly larger impact than the Repsol LNG import in part due to the difference in the length of the winter supply offered by each LNG facility. Over the first half of the analysis period, GDF Suez LNG and Respol LNG reduced average monthly winter basis by $1.52/MMBtu and $1.12/MMBtu respectively.

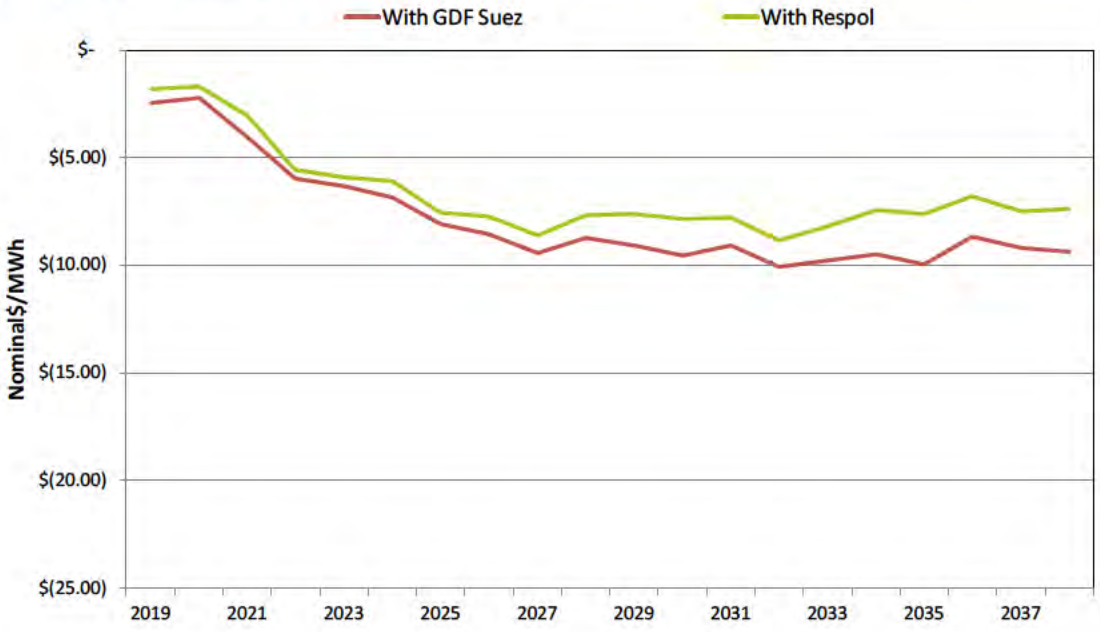
The ANE pipeline has a larger long-term natural gas price impact than the LNG import solutions. Table 5 below compares the impact on winter Algonquin city-gates basis between the ANE pipeline solution and the LNG import scenarios.

Table 5: Summary Algonquin city-gates Average Monthly Winter (Dec-Feb) Basis Impact

	Algonquin City Gates ($/MMBtu)			
	2019 - 2028		2029-2038	
	Average Monthly Winter (Dec-Feb) Basis	Differential to Reference Case	Average Monthly Winter (Dec-Feb) Basis	Differential to Reference Case
Reference Case	$ 4.07		$ 6.79	
With ANE Only	$ 1.57	$ (2.50)	$ 3.55	$ (3.24)
With Repsol Canaport LNG	$ 2.95	$ (1.12)	$ 6.34	$ (0.45)
With GDF Suez Everett LNG	$ 2.55	$ (1.52)	$ 5.39	$ (1.40)

Similar to the ANE project, the reduction in regional natural gas prices during the peak winter periods from the LNG import solutions translates to lower regional electric prices. In Figure 11, the average annual electric price reduction over the twenty year analysis period with the GDF Suez LNG proposal was $7.85/MWh while the price reduction of the Repsol LNG proposal was $6.64/MWh.

Figure 11: Projected Electric Market Price Impact across LNG Scenarios – New England Weighted Average Price (Nominal$/MWh)

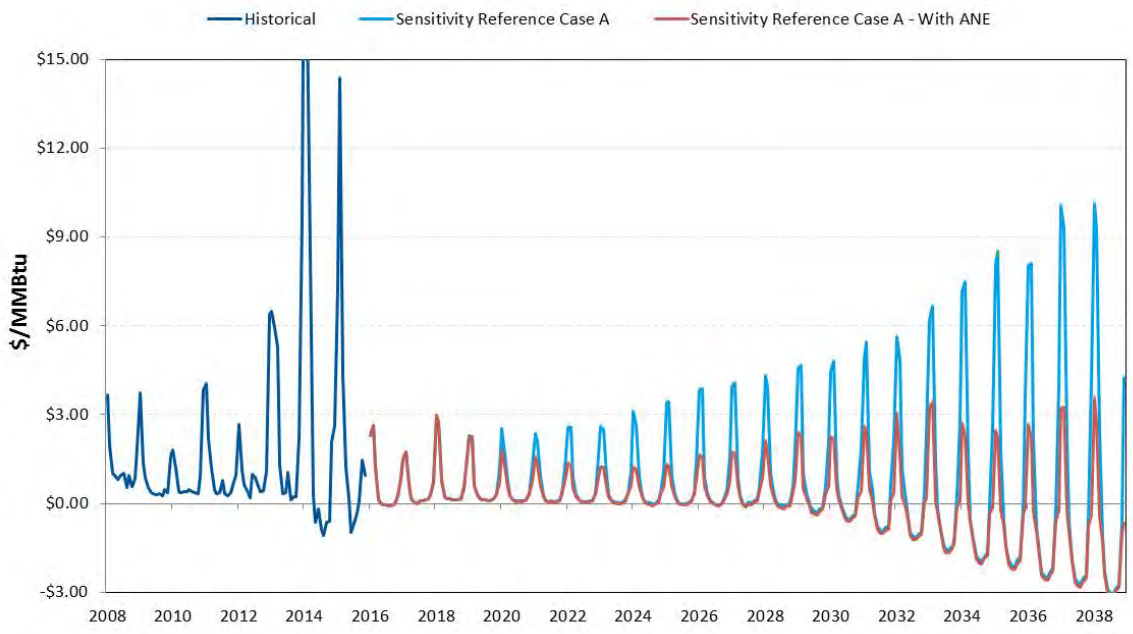


8.0 Natural Gas and Electric Price Impacts – Sensitivity Reference Cases

Compared to both Sensitivity Reference Cases A and B, the ANE Pipeline project is expected to reduce Algonquin city-gates basis and reduce daily price volatility during the winter months. The Sensitivity Reference Cases A and B were used as benchmarks when quantifying the benefits of the ANE Pipeline in the context of substantial incremental clean energy generation and associated transmission.

The impact of the ANE Pipeline compared to both Sensitivity Reference Cases A and B is lower in the first half of the analysis period, when compared to the ANE impact versus the Reference Case, but the impact of the ANE project on gas prices reaches comparable levels when compared to all three reference cases in the latter half of the analysis period. Figure 12 below shows impact of the ANE pipeline under Sensitivity Reference Case A.

Figure 12: Projected Natural Gas Basis Impact across Sensitivity Reference Case A – Algonquin, city-gates



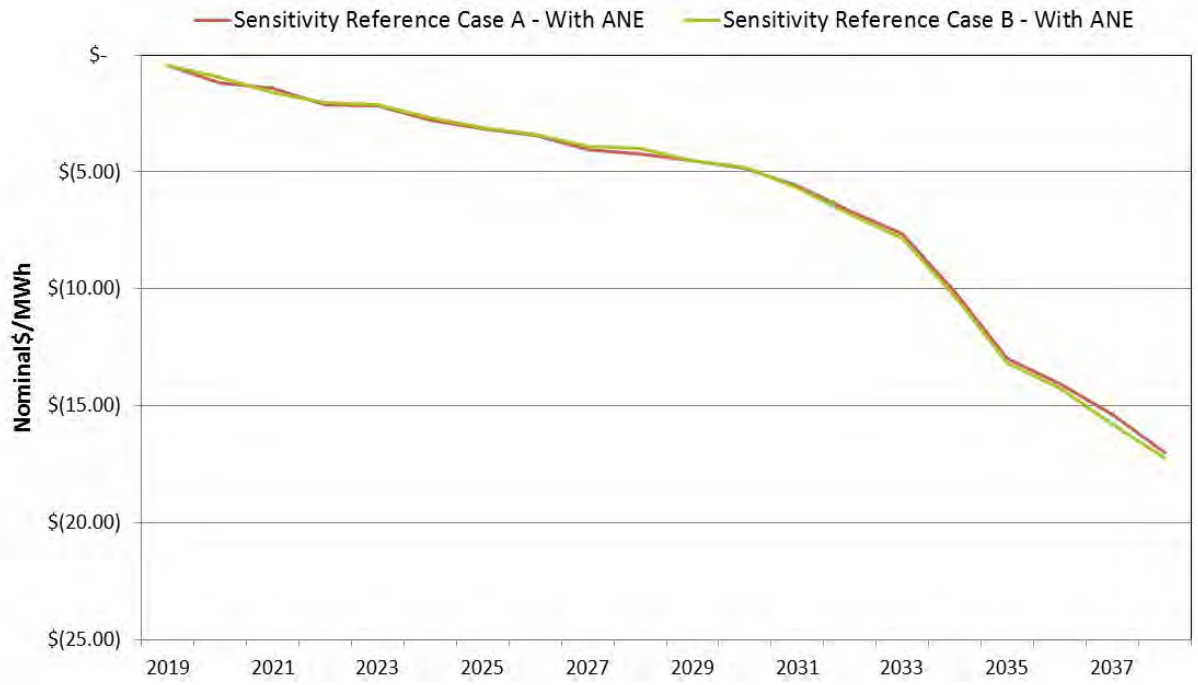
The overall impact of the ANE Pipeline is generally similar whether measured against the Reference Case or the sensitivity reference cases. The ANE Pipeline was projected to reduce regional basis when compared to each reference case. Table 6 below compares the ANE Pipeline impact to winter Algonquin city-gates basis.

Table 6: Summary Algonquin city-gates Average Monthly Winter (Dec-Feb) Basis Impact

	Algonquin City Gates ($/MMBtu)			
	2019 - 2028		2029-2038	
	Average Monthly Winter (Dec-Feb) Basis	Differential to Reference Case	Average Monthly Winter (Dec-Feb) Basis	Differential to Reference Case
Reference Case	$ 4.07		$ 6.79	
With ANE Only	$ 1.57	$ (2.50)	$ 3.55	$ (3.24)
Sensitivity Reference Case A	$ 2.59		$ 5.69	
With ANE	$ 1.34	$ (1.25)	$ 1.72	$ (3.97)
Sensitivity Reference Case B	$ 2.54		$ 5.64	
With ANE	$ 1.29	$ (1.24)	$ 1.66	$ (3.98)

Similar to the scenario With ANE Only layered on the Reference Case, the reduction in regional natural gas prices during the peak winter periods from the proposed ANE Pipeline translate to lower regional electric prices when compared against the sensitivity reference cases. In Figure 13, the average annual electric price reduction over the twenty-year analysis period for ANE is similar across both sensitivity reference cases. The average annual ANE electric price reduction under Sensitivity Reference Case A is $6.19/MWh while the price reduction under Sensitivity Reference Case B is $6.23/MWh.

Figure 13: Projected Electric Market Price Impact across Sensitivity Reference Cases – New England Weighted Average Price (Nominal$/MWh)

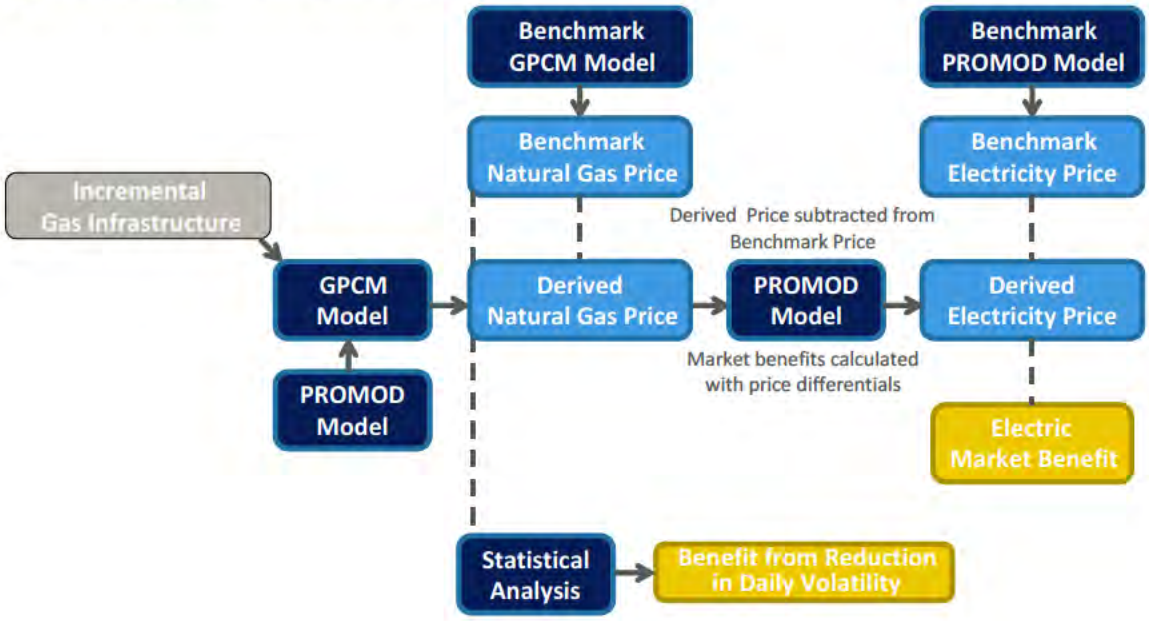


9.0 Benefits to New England Energy Consumers

Methodology for Benefits Calculation

Black & Veatch evaluated the long-term economic benefits of the proposed natural gas infrastructure solutions for New England regional electric customers. Figure 14 provides an overview of the analytical process used to assess these benefits. The estimation of benefits is interdependent for gas and power customers because of the interrelationships in the market between power generation economics and the economics of gas as a generation fuel.

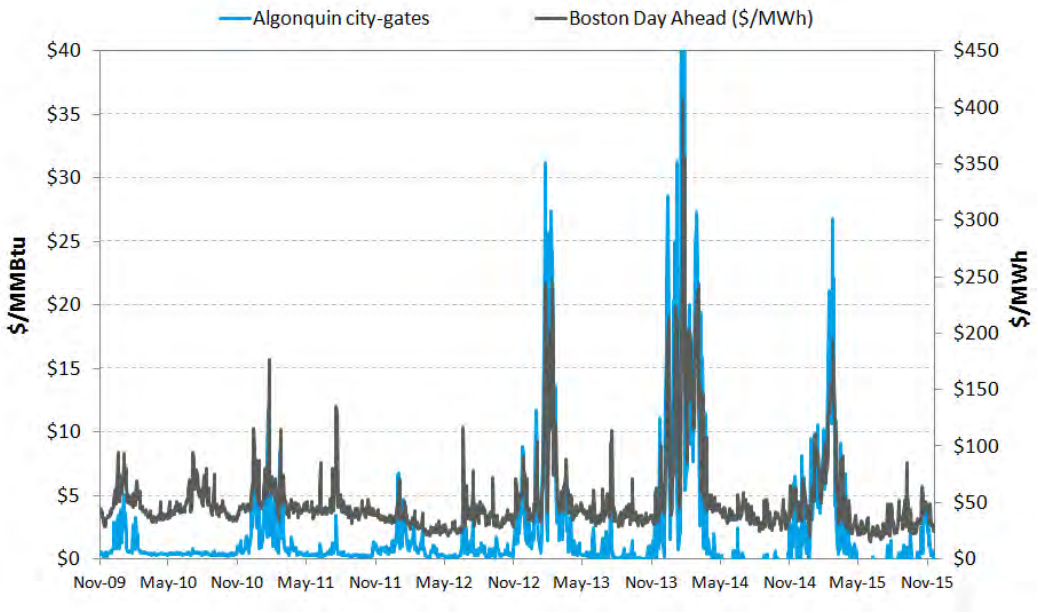
Figure 14: Analytical Process used to Assess Market Benefits



Benefits to Electric Customers

Because most natural gas-fired power generation capacity in New England is not supported by firm transportation contracts on natural gas pipelines, the cost of gas-fired power generation is closely tied to wholesale natural gas spot market prices. Therefore, New England's electricity prices across all ISO-NE zones are highly correlated with regional wholesale natural gas spot market prices. Figure 15 illustrates the close historical connection between New England's electricity and natural gas wholesale spot market prices at the Algonquin city-gates, especially during winter months.

Figure 15: Historical New England Electric and Natural Gas Prices



Source: ISO-NE, Platts

Because of the high correlation between natural gas spot prices and wholesale electric prices, natural gas price reductions associated with each proposed pipeline project would translate directly to economic benefits to New England electric customers. Benefits to electric customers are calculated as the reduction in market energy prices in each ISO-NE zone multiplied by total energy consumption in that zone.

Benefits from Reduced Daily Gas Price Volatility

In addition to the overall price decreases modeled above, natural gas end-users and electric customers also benefit from reductions in daily natural gas price volatility. Incremental gas infrastructure additions, increased gas supply, or reduced power-sector demand all provide relief from supply constraints and will also reduce daily price volatility. For example, New England winter basis could increase by more than $30/MMBtu in a single day, while the daily increase in summer daily basis never exceeds $1/MMBtu, given the absence of capacity constraints. Because power generators make energy market offer decisions based on daily gas prices, daily price volatility for gas has a very significant impact on electric customers.

Because the price estimates were calculated using monthly forecasts, the benefits of reduced price volatility were separately calculated using a statistical modeling approach. First, Black & Veatch examined the historical relationship between wholesale daily spot and first-of-month natural gas prices reported at Algonquin city-gates in order to determine how often, and by how much, daily spot prices exceed first-of-month prices in peak winter months. That relationship was then used to derive daily price projections using the monthly model output. In this analysis, Black & Veatch assumed that, with the incremental pipeline capacity, the daily price spikes are reduced in magnitude and frequency from a moderately volatile market to a less volatile market similar to the winter seasons prior to 2012-2013.

The reductions in daily gas price volatility due to incremental pipeline capacity were then used to estimate the corresponding additional reduction in electric market prices.

Electric Benefits Summary

The ANE pipeline project is expected to provide significant long-term benefits to New England electric consumers. Incremental pipeline capacity with firm gas supply into the region will also enhance ISO-NE's electric system reliability, as the proposed ANE pipeline project can reach most existing and proposed gas-fired generators. Access to gas supplies on a primary firm basis will allow generators to dispatch during peak winter periods and avoid future performance penalties.

In addition to creating direct benefits to the region's energy consumers, secondary economic benefits like creating new construction and operating jobs will increase income and help grow the economy. The reduction of energy costs will allow local consumers and businesses to invest and spend on other regional goods and services.

Compared to the Reference Case, the ANE project will be able to create approximately [redacted] in annual levelized electric consumer net benefits over the contract length, as shown in Table 7.[8] New England electric consumers are projected to realize $10.2 Billion in total present value of net benefits from ANE.

When compared to Sensitivity Reference Cases A and B, the ANE project still creates approximately $0.4 Billion in annual levelized electric consumer net benefits in each case over the contract length, as shown in Table 5. New England electric consumers are projected to realize $3.5 Billion in total present value of net benefits for ANE under both Sensitivity Reference Cases A and B.

The proposed LNG import solutions also create long-term benefits to electric consumers. Individually, the GDF Suez and Repsol proposal are projected to yield $0.6 and $0.2 Billion, respectively, in annual levelized electric consumer net benefits over the analysis period. The projected total present value of net benefits for New England electric consumers from GDP Suez and Repsol is $4.9 Billion and $2.1 Billion, respectively.

[8] Black & Veatch discounted annual benefits and costs to present values and calculated levelized values using the same discount rate of 7.06% used in the companion study prepared by Black & Veatch for Narragansett Electric Company's affiliates in Massachusetts and filed in Docket No. D.P.U. 16-05. In that companion study, 7.06% represented the current nominal weighted average cost of capital. The weighted average cost of capital is the discount rate that the Massachusetts Department of Public Utilities directed utilities to use in their recent benefit-cost analyses for their grid modernization plans. D.P.U. 12-76-C, at 18-19.

Table 7: Summary of Total Costs and Benefits across Scenarios [9]

Project Cost-Benefits Summary 2019-2038 ($ Billions)							
	Levelized			Present Value			
Project	Annual Benefits	Annual Costs	Annual Net Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Reference Case - With ANE Only	[redacted]		$1.1	[redacted]		$10.2	[redacted]
Sensitivity Reference Case A - With ANE			$0.4			$3.5	
Sensitivity Reference Case B - With ANE			$0.4			$3.5	
Reference Case - With GDF Suez			$0.6			$4.9	
Reference Case - With Repsol			$0.2			$2.1	

RI Electric Benefits Summary

Black & Veatch utilized two methodologies to calculate the levelized annual benefits to Rhode Island. The first method utilized the location marginal prices in Rhode Island to calculate the levelized annual benefit, while the second method used an allocated approach based on Rhode Island's state's share of ISO-NE's monthly peak electric loads. For costs, Black & Veatch used an allocation factor based on its share of the region's coincidental peak electric load, minus any municipal or Co-op electrical peak loads, which is 7.2% of the annual projected costs.

Using the Rhode Island LMP price differentials to calculate the levelized annual benefits resulted in $0.11 Billion in levelized annual net benefits to Rhode Island from ANE relative to the Reference Case, as shown in Table 8. Under the Sensitivity Reference Cases A and B, the levelized annual net benefits to Rhode Island from ANE are approximately $0.04 Billion. The LNG import proposals would result in $0.05 and $0.02 Billion in levelized annual net benefits from GDF Suez and Repsol, respectively, for Rhode Island.

[9] Black & Veatch estimated that approximately 96% of the gross electricity market benefits occur during the winter season (October-March) for the 2019-2038 analysis period for the ANE only scenario.

Table 8: Summary of Rhode Island Total Costs and Benefits across Scenarios (Based on LMP Prices)

Project Cost-Benefits Summary 2019-2038 ($ Billions)							
	Levelized			Present Value			
Project	Annual Benefits	Annual Costs	Annual Net Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Reference Case - With ANE Only	[redacted]		$0.11	[redacted]		$0.97	[redacted]
Sensitivity Reference Case A - With ANE			$0.04			$0.35	
Sensitivity Reference Case B - With ANE			$0.04			$0.36	
Reference Case - With GDF Suez			$0.05			$0.46	
Reference Case - With Repsol			$0.02			$0.21	

Using an allocated approach results in a moderate decrease in benefits across all scenarios compared to the net benefits calculated by LMP price differentials. Apportioning Rhode Island's share of total New England benefits and costs resulted in $0.07 Billion in levelized annual net benefits to Rhode Island from ANE relative to the Reference Case, as shown in Table 9. Under the Sensitivity Reference Cases A and B, the levelized annual net benefits to Rhode Island from ANE are approximately $0.02 Billion. The LNG import proposals would result in $0.03 and $0.01 Billion in levelized annual net benefits from GDF Suez and Repsol, respectively, for Rhode Island.

Table 9: Summary of Rhode Island Total Costs and Benefits across Scenarios (Based on Electric Load Allocation)

Project Cost-Benefits Summary 2019-2038 ($ Billions)							
	Levelized			Present Value			
Project	Annual Benefits	Annual Costs	Annual Net Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Reference Case - With ANE Only	[redacted]		$0.07	[redacted]		$0.63	[redacted]
Sensitivity Reference Case A - With ANE			$0.02			$0.20	
Sensitivity Reference Case B - With ANE			$0.02			$0.20	
Reference Case - With GDF Suez			$0.03			$0.29	
Reference Case - With Repsol			$0.01			$0.12	

10.0 Projected Regional Emissions Impact of ANE

Methodology to Projected Air Emissions Impact

Black & Veatch utilized the PROMOD model results to analyze the projected regional air quality and emissions impact from power generation from the proposed ANE pipeline project. Comparing the With ANE Only case to the Reference Case finds an approximately 15% reduction in NOx, a 25% reduction in SOx, and a 0.85% reduction in GHG for the New England region over the analysis period.

Overall, Black & Veatch believes that the ANE pipeline can have a positive impact in improving regional air quality and reducing greenhouse gas emissions from the power generation sector. Gas-fired generation can play an important role in renewable integration, and the ANE pipeline can provide natural gas to generation units across the region.

Table 10: Comparison of Projected Emissions Reductions across Scenarios - 2019-2038

TOTAL POLLUTANT EMISSIONS 2019-2038			
Scenarios	**NO_X (Thousand Tons)**	**SO_2 Thousand Tons)**	**Greenhouse Gases (Million Tons $CO_{2)}$**
Reference Case	114	135	7.0
Reference Case - With ANE Only	96	100	6.9
Sensitivity Reference Case A	65	43	6.2
Sensitivity Reference Case A – With ANE	56	18	6.1
Sensitivity Reference Case B	52	16	5.7
Sensitivity Reference Case B – With ANE	52	15	5.7

Under Sensitivity Reference Case A, the ANE pipeline is projected to have a similar regional impact, reducing NOx by 14%, SOx by 58%, and a 0.25% reduction in GHG over the analysis period. Compared to Sensitivity Reference Case B, air emissions are relatively unchanged by the ANE project.

APPENDIX

Black & Veatch developed additional analysis to understand the impact of the discount rate on our projected long-term economic benefits to electric consumers. For comparability, we used the same discount rate in this study (7.06%) as in the companion study filed in Massachusetts in D.P.U. 16-05.[10] The lower discount rate used in the tables below is the nominal discount rate of 2.54% used by National Grid for analysis of the costs and benefits associated with energy efficiency programs in Rhode Island.

Summary of Total Costs and Benefits across Scenarios – Lower Discount Rate Scenario (2.54%)

Project Cost-Benefits Summary 2019-2038 ($ Billions)							
	Levelized			Present Value			
Project	Annual Benefits	Annual Costs	Annual Net Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Reference Case - With ANE Only	[redacted]		$1.3	[redacted]		$18.6	[redacted]
Sensitivity Reference Case A - With ANE			$0.6			$8.1	
Sensitivity Reference Case B - With ANE			$0.6			$8.2	
Reference Case - With GDF Suez			$0.6			$8.7	
Reference Case - With Repsol			$0.2			$3.3	

When using a low discount rate, as shown in the table above, the levelized annual net benefits for most scenarios generally increased, and the benefit to cost ratios are slightly higher. Overall, the low discount rate does not change the conclusion that the ANE pipeline project creates significant long-term economic benefit to electric consumers. The LNG import solutions also offer long-term benefits albeit at lower levels and with lower benefit-to-cost ratios.

[10] See Exhibit NG-JNC-3 in Docket No. D.P.U. 16-05.

Summary of Rhode Island Costs and Benefits across Scenarios (Based on LMP Prices)

– Lower Discount Rate Scenario (2.54%)

Project Cost-Benefits Summary 2019-2038 ($ Billions)							
	Levelized			Present Value			
Project	Annual Benefits	Annual Costs	Annual Net Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Reference Case - With ANE Only	[redacted]		$0.12	[redacted]		$1.77	[redacted]
Sensitivity Reference Case A - With ANE			$0.05			$0.79	
Sensitivity Reference Case B - With ANE			$0.05			$0.79	
Reference Case - With GDF Suez			$0.06			$0.81	
Reference Case - With Repsol			$0.02			$0.32	

On a state level, the lower discount rate increase annual net benefits across all scenarios and both benefit methodologies as discussed Section 9. For Rhode Island electric consumers, the benefit-to-cost ratios are higher as well, and would benefit from developing the ANE pipeline solution.

Summary of Rhode Island Costs and Benefits across Scenarios (Based on Electric Load Allocation)

– Lower Discount Rate Scenario (2.54%)

Project Cost-Benefits Summary 2019-2038 ($ Billions)							
	Levelized			Present Value			
Project	Annual Benefits	Annual Costs	Annual Net Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Reference Case - With ANE Only	[redacted]		$0.08	[redacted]		$1.16	[redacted]
Sensitivity Reference Case A - With ANE			$0.03			$0.48	
Sensitivity Reference Case B - With ANE			$0.03			$0.48	
Reference Case - With GDF Suez			$0.04			$0.52	
Reference Case - With Repsol			$0.01			$0.18	

Schedule GJW-4
Curriculum Vitae

Gary Wilmes

Mr. Wilmes is a registered Professional Engineer with diverse experience in many aspects of the electric power industry, including system planning, production cost modeling, economic analysis, electricity market assessments, and conceptual design. He has conducted several system planning and feasibility studies for domestic and international clients. His activities have included technology screening and selection studies, development of utility generation expansion plans, generating system production cost simulation and analysis and reliability/availability assessments to predict plant availability and improvements attributable to proposed plant design changes. He has been involved in power plant site selection studies where he used GIS mapping tools and spatial databases to identify preferred sites for new power plants. Mr. Wilmes has evaluated the economics of proposed DSM and Energy Efficiency programs using the DSMore (Demand Side Management Option Risk Evaluator) simulator as well as detailed hourly chronological production cost models such as ProSym and ProMod to evaluate the economics of peak reductions and energy cost savings attributable to DSM and Energy Efficiency programs. He has extensive experience in the use of full suite of PowerBase and EnerPrise products. He is experienced in managing data gathering to develop customized databases for input to these models. Mr. Wilmes possesses strong financial analysis skills, supported by thorough knowledge of financial, economic and accounting principles. He has a strong technical understanding of the electric utility industry and excellent analytical problem-solving skills, including quantitative analysis and computer modeling techniques.

Mr. Wilmes has used his expertise in the areas of linear programming, mixed-integer programming, dynamic programming, and non-linear programming on several projects. Mr. Wilmes co-developed Black & Veatch's PowrPro chronological production costing program. PowrPro contains numerous features to realistically model actual unit commitment and dispatch. Mr. Wilmes authored Black & Veatch's PowrOpt, optimal generation expansion program. PowrOpt uses a dynamic program in conjunction with the commitment and dispatch algorithms of PowrPro to determine the least-cost expansion plans meeting reliability criteria determined by reserve margin or loss-of-load probability (LOLP).

Mr. Wilmes developed a fuel purchase optimization system in support of a Total Fuel Management system software development project. The optimizer provides the capability to evaluate a large number of fuel purchase options while simultaneously accounting for system-wide and unit-specific constraints, coal delivery options, governmental regulations and inventory levels, as well as fuel purchase cost. On another project, Mr. Wilmes developed an optimizer for use in an Integrated Fuel Strategy Study that determined the set of development options that consist of fuel, transportation and capital improvement strategies that optimizes system profitability.

SENIOR CONSULTANT

Specialization:
Power Generation System Planning, Asset Valuation, Market Price Forecasting, and LMP Analysis

Education
- B.S., Agricultural Engineering (with high distinction), University of Nebraska – Lincoln, 1987
- M.S., Manufacturing Systems Engineering, University of Nebraska – Lincoln, 1992

Professional Registration
Registered Engineer, Kansas

Year Career Started
1987

Joined Black & Veatch
1992

Prior to joining Black & Veatch, Mr. Wilmes was a Research Engineer at the University of Nebraska at Lincoln. At the university, he performed research to measure crop yield response to timings and quantities of fertilizer and water applications. These experimental results were used to build crop simulation models that were used to develop Decision Support Systems to advise producers on the timing and quantities of water and fertilizer applications to maximize profit under limited water constraints. These models were also used to advise policymakers on the economic impacts of limiting aquifer withdrawals to maintain a sustainable water supply and for limiting fertilizer and chemical applications to maintain water quality

PROJECT EXPERIENCE

Florida Municipal Power Association (FMPA) Resource Planning Support | 2014

Mr. Wilmes worked with FMPA to provide resource planning support activities for their IRP efforts. Mr. Wilmes used the Ventyx Strategist model to produce optimal capacity expansion plans to meet FMPA's capacity needs going forward.

Confidential Midwest Utility | 2013 to current

Mr. Wilmes is providing ongoing support in detailed financial and production cost analysis of resource replacement and emission retrofit options for coal units owned by a Midwest utility. Resource replacement options include retrofitting air pollution control (APC) systems, conversion to natural gas, conversion to combined cycle facility, and retirement.

Grand Prairie 400 MW Wind Economic Analysis | 2013

Black & Veatch performed an economic analysis of the 400 MW Grand Prairie wind farm located in western Nebraska. A utility was offered an unsolicited PPA for output from the Grand Prairie Wind farm. Black & Veatch provided a recommendation on execution of the PPA to senior management and the utility's Board of Directors. Mr. Wilmes performed short term security constrained economic dispatch (SCED) analysis for the potential purchase. The SCED analysis examined the future market structure and market demand, and included major backbone transmission additions that could affect the operation of the asset. Projections of market energy prices, unit production, curtailment, and key congestion facilities for the project node were provided, as well as performance projections, cost projections, and revenue projections.

Confidential Nuclear Restart Analysis | 2013

Mr. Wilmes provided nodal price analysis in support of restart analysis of an existing nuclear power plant. The nuclear power plant was shut down and required major capital and fixed O&M expense before the unit was allowed back online. The analysis included an economic evaluation of restarting the plant compared to alternative resource options.

West Texas Municipal Power Agency | Integrated Resource Plan, Lubbock, Tex. | 2013

In preparing an Integrated Resource Plan (IRP) for the West Texas Municipal Power Agency (WTMPA), Mr. Wilmes analyzed power supply alternatives beginning upon expiration of WTMPA's existing full requirements power purchase from Southwestern Public Service Co. (SPS), a wholly-owned subsidiary of Xcel Energy, Inc. (Xcel). WTMPA is a joint power agency and municipal corporation comprised of four cities in Texas; Lubbock being the largest member. The WTMPA IRP considered various solutions to meeting the power requirements of WTMPA upon expiration of its existing fuel requirements power purchase. The IRP considered self-owned generation in combination with participation in the Southwest Power Pool (SPP) Integrated Marketplace. Mr. Wilmes performed the Strategist capacity expansion optimization modeling the ProMod production cost modeling for the study. As part of the IRP process, Mr. Wilmes help prepare a presentation of the results of the IRP for presentation to both the WTMPA and City of Lubbock Board of Directors.

Tyr Energy | EIF Portfolio of Four Gas Units | 2012-2013

Project Manager and performed site visits for two assets for the independent engineering assessment of a four unit gas fired portfolio including 501FC, 7FA, and Wartsila technologies. Upon successful PSA execution, Black & Veatch advised multiple technical teams evaluating the potential acquisition of the company.

Confidential Client | Granite Ridge | 2012

Mr. Wilmes was responsible for coordinating the report detailing the independent engineering assessment on behalf of a potential buyer of a 2x1 SW 501G combined cycle project.

Village of Rockville Centre | Integrated Resource Plan, N.Y. | 2012

Developed electric load forecast for an integrated resource plan (IRP) study for the Village of Rockville Centre. The IRP included consideration of RVC's existing generating system and strategic planning to satisfy forecasted system requirements. The strategic planning process included consideration of conventional supply-side options, interaction with the purchase power market, demand-side management measures, and possible future environmental impacts.

Various Clients | Independent Engineer, United States| 2011 - Present

Mr. Wilmes has been Project Manager on, or otherwise supported, numerous independent engineering/due diligence engagements for various clients considering either purchasing or selling individual assets or portfolios of assets. Activities included coordinating the activities of specialists involved in the engagements, communication with clients, developments of reports, and site visits.

Black & Veatch| Energy Market Perspective | 2008 - Present

SPP region expert for the Black & Veatch Midwest Energy Market Perspective and is responsible for developing the Black & Veatch outlook of SPP power markets that is updated every six months. The Energy Market Perspective (EMP) is a 25 year fundamental baseline view of electric, gas, oil, and capacity prices across major pricing points across the US power markets. The EMP leverages the PROMOD production cost model to forecast hourly electricity prices over a long term horizon. Prior to his focus on the SPP region, Mr. Wilmes was also the region expert for PJM.

Various Portfolios | 2007 - Present

Mr. Wilmes has provided technical due diligence and strategic advisory services to domestic and international clients who are involved in various electric facility transactions, re-financing, and development activities of assets located around the world.

Delek Infrastructure Ltd. | Next Era Portfolio Valuation, Israel | 2011

Black & Veatch was retained by an Israeli based private equity firm looking for buy-side transaction support of the NextEra power plant portfolio up for sale. Mr. Wilmes provided a market based valuation of combined cycle assets located in the Midwest Region.

MECO | Feasibility Analysis for Pumped Storage Hydroelectric Project | 2011

Performed preliminary economic feasibility of using variable speed pumped storage hydroelectric (PSH) generation to provide storage of intermittent renewable generation during lower electric demand hours for use during higher demand hours, storage of generation from lower cost thermal generators available when system electric loads are low for use in lieu of more expensive thermal generators when system electric loads are higher, and delay in the need to add new generating capacity to maintain required capacity reserves. The electric system planning models Strategist and PROMOD were used to model the expansion and operation of the MECO system under four separate plans with and without the PSH plant, with a smaller version of the PSH plant and with the PSH plant but without the 25 MW purchase of power from a new dedicated biomass plant.

State Grid International Development | US Wind Portfolio Valuation | 2011-2012

Mr. Wilmes was part of a large team tasked to work with State Grid International Development (SGID) located in China and the investment bank of Morgan Stanley evaluating the potential acquisition of a portfolio of wind plants located across the U.S. Black & Veatch provided Morgan Stanley a long term forecast of energy, capacity, and renewable energy credit (REC) prices that the wind portfolio could earn in each of the US power markets.

Southwest Power Pool (SPP) | Southwest Power Pool Integrated Transmission Plan (ITP) Year 20 Assessment; Little Rock, Ark.

SPP retained Black & Veatch to provide assistance in developing 20-year forecasts of resource additions to maintain loads and resources balances throughout SPP. The forecasts of resource additions were used by SPP in performing the ITP Year 20 Assessment. The ITP process is designed to provide guidance on SPP's near- and long- term transmission infrastructure needs. Black & Veatch developed four, 20-year forecasts of load and resource balances throughout SPP based on four future scenarios. The project included the development of a resource plan, GIS location of resources within SPP, and integration of resources into SPP transmission models.

Board of Public Utilities | DSM Planning; Kansas City, Kan.

Evaluated the economics of proposed DSM programs using the DSMore (Demand Side Management Option Risk Evaluator) simulator. Assembled the data needed to develop customized price and load profiles for the DSMore program. Also used the ProSym based Planning and Risk software to evaluate economics of peak reductions attributable to DSM programs.

ISEPA | Compressed Air Energy Storage Study

Performed an analysis of the net systems benefits of adding a Compressed Air Energy Storage (CAES) unit to a Midwest utility's existing generation portfolio. The operation of the CAES unit was modeled using the ProMod production cost modeling software. The total system production cost with and without the CAES unit were compared to determine the net benefit of the CAES unit to the utility.

Board of Public Utilities | Power Supply Planning Study; Kansas City, Kan.

Performed the system modeling simulations associated with a power supply planning study used to develop a generation expansion plan for the BPU considering future anticipated environmental regulations.

Confidential Client | Asset Valuation of Portfolio of Generation Facilities

Developed electric models of the WECC system to forecast market revenue streams of a portfolio of generation assets to evaluate the value of the assets offered for sale. The analysis was used to support the development of a bid for the purchase of the assets.

Confidential Client | Study of Transmission Expansion Alternatives

Performed an analysis of three transmission expansion alternatives by developing a detailed nodal transmission ProMod model of the Eastern Interconnect. The benefit to total production cost, locational marginal prices, and net cost to serve load was compared for the three alternatives.

Confidential Client | Electric Waste Coal and Gas Turbine Plants Valuation, Confidential Client

Developed the electric market price forecast for the West PJM region and the FRCC and SERC regions of the Southeastern United States by creating and using electric market models of the areas to estimate the value of the plants offered for sale to a group of investors.

Western Farmers Electric Cooperative | Electric Market Price Forecast Study

Developed electric market price forecast for the SPP region by modeling SPP, MRO and the AECI and Entergy sub-regions of SERC and relevant connected areas in support of Integrated Resource Planning study.

Board of Public Utilities|Integrated Resource Plan; Kansas City, Kan.

Conducted an integrated resource planning study and developed an integrated resource plan (IRP) defining the system upgrades, modifications, and additions that will be required to ensure reliable and least cost electric service to the BPU customers.

StatOil| LNG Facility Expansion Strategy Study; Stamford, Conn.

Developed electric market model for the PJM region and connected areas and integrated with NARG gas model to forecast electric prices, natural gas consumption, and natural gas prices in support of Cove Point LNG facility expansion strategy study.

ELCEN | Combined Heat and Power Production Cost Study; Bucharest, Romania

Developed production cost model of ELCEN cogeneration units used for district heating and electricity generation. The model was used to analyze proposed plant upgrades and modifications. A ranking of most cost effective alternatives was developed.

City of Tallahassee | Electric Market Price Forecast Study; Fla.

Developed electric market price forecast for the FRCC and SERC regions by modeling FRCC, SERC, and relevant connected areas in support of an integrated resource planning study.

CEG | Emissions Strategy Study; Baltimore, Md.

Developed electric market price forecast for the PJM region by modeling PJM and connected areas in support of emissions control strategy study.

Board of Public Utilities|Master Plan Update; Kansas City, Kan.

Modeled BPU's electric generation system using planning and risk model in support of master plan update.

United States Coast Guard | Facility Security Plans (FSP) Review Program

Supported the United States Coast Guard (USCG) in implementing Title 33 US Code of Federal Regulations as it pertains to maritime Facility Security Plans. This program was implemented under the direction of the U.S. Department of Homeland Security and was designed to protect the nation's ports and waterways from a terrorist attack. The security plans encompassed not only ocean seaports, but also ports located within the interior of the US (river and Great Lakes ports); marine facilities located along and adjacent to the water (petroleum, cargo, gas processing); and off-shore oil and gas platforms.

Confidential Client | Power Supply Planning Study

Conducted an Electric Market Price analysis for the Eastern Interconnect with a focus on SPP. The Electric Market Clearing price was used to estimate hourly energy purchase and sales prices for locations interconnect to the client's system. Analyzed several expansion plans using ProSym under fuel price, load, and fuel cost scenarios. Both tasks completed as part of a 20-year power supply planning study.

Board of Public Utilities|Cost of Service Study; Kansas City, Kan.

Modeled BPU's electric generation system using ProSym in support of their Cost of Service filing.

Irving Oil |Economic Evaluation of Bayside; Saint John, NB, Canada

Developed a competitive electric power market model and electric price forecast for the ISO New England (NEPOOL) sub-region of the Northeast Power Coordinating Council (NPCC) of the North American Electric Reliability Council in support of a power plant valuation.

City of Tallahassee|Tallahassee Planning Engineering Services; Fla.

Conducted an Electric Market Price analysis for the SERC and FRCC NERC regions as part of a 20-year integrated resource planning study.. The Electric Market Clearing price was used to estimate hourly energy purchase and sales prices. Also conducted a reliability analysis and developed Reserve Margin vs. system cost and Reserve Margin vs. LOLP relationships. Analyzed several expansion plans using ProSym under transmission capacity, demand, market clearing price, fuel cost, and capital cost sensitivity scenarios.

WSCC |Market Clearing Price Forecast, Texaco Power and Gasification; Burbank, Calif.

Electric market clearing prices for areas in WSCC were developed for use in project feasibility analysis. The electric market clearing prices estimates were also used for a major university's central plant assessment study.

region Updated the EMSS database for the WSCC region with projected new units coming online based on our research as part of a 15-year electric market

price study for four subregions within the WSCC. Used ProSym to model the WSCC region under several scenarios. Also developed a study report.

Great Lakes|Utilities Great Lakes Integrated Resource Planning Study,; Wisc.

Participated in a 20-year integrated resource planning study for Great Lakes Utilities. Discussed clients' requirements, objectives, and situations. Developed composite load profiles by combining loads from member utilities. Analyzed alternative plans and recommended least cost alternatives. Prepared the report and presented results to the member utilities.

JEA |JEA Clean / Green Power Equivalency Algorithms; Jacksonville, Fla.

Developed a methodology and the algorithms whereby clean power initiatives can be equated to green power counterparts.

Florida Power Corporation| FPC Hines No. 2 NFP Alternative Assessment; St. Petersburg, Fla.

Prepared an analysis report of supply side alternatives, which were incorporated with the Need for Power Application for Florida Power's Hines No. 2 Combined Cycle Unit. Analysis included study of renewable technologies, waste technologies, advanced technologies, energy storage systems, and nuclear technologies, as well as conventional technologies and repower alternative.

Orlando Utilities Commission | OUC 10 Year Site Plan / Stanton No. 3 NFP; Fla.

Assisted in modeling of OUC's generation system using PowrOpt and PowrPro, Black & Veatch's optimal generation expansion model and production costing model, respectively, in support of Stanton No.3 Need for Power hearing.

Lakeland Electric | Lakeland 10 Year Site Plan / McIntosh No. 4 NFP; Fla.

Mr. Wilmes assisted in modeling of Lakeland's generation system in support of McIntosh No. 4 Need for Power hearing.

Kissimmee Utility Authority (KUA) | Generating Alternatives and 10 Year Site Plan; Fla.

Coordinated development of capital costs, O&M costs, and performance estimates for several generator alternatives in support of KUA's 10 year site plan process. Also provided consulting support for modeling of KUA's generation system and assisted on a 10 year site plan report.

Reliant Energy | Plant Siting Study / Site Selection; Houston, Tex.

Used POWERmap and POWERdat to help identify locations with potential to be location sites for LM 6000 combustion turbines. Also developed maps for use in presentation to client.

JEA | IRP Services; Fla.

Provided capital costs, O&M costs and performance estimates for several generator alternatives in support of JEA's integrated resource planning process.

Dominion Generation | Dominion Siting Studies; Richmond, Va.

These studies identified several potential locations to site combustion turbine based simple cycle and combined cycle power plants. Used spatial data, location specific market clearing price projections, and available existing infrastructure to determine locations. Determined sites within the following areas: ECAR region, PJM region, NYPP region, North Carolina / Virginia, and along Midwest pipelines.

Southern Company Generation| TFM/STO/Southern Company; Atlanta, Ga.

Modified previously developed fuel purchase optimization model to meet Southern Company's requirements using acquired proficiencies in modeling and optimization.

Reliant Energy | Generating Technologies Performance and Cost Estimates; Houston, Tex.

This study provided conceptual level cost and performance for six simple cycle combustion turbine power plant configurations for consideration in generation expansion planning alternatives.

Enron Engineering and Construction Company| Marmara Ereglisi Turkey Power Station Alternate Fuels Study; Ereglisi, Turkey

Performed a study that provided an overview of the plant modifications, capital costs, and operational changes necessary for the alternate fuels, naphtha and natural gas condensates, to be used at the Marmara Ereglisi Power Plant. Plant performance characteristics, emissions, and schedule for the construction, startup, and commissioning activities were investigated.

Virginia Power | TFM Fuel Purchase Optimization Model; Richmond, Va.

Customized the TFM Fuel Purchase Optimization Model to meet Virginia Power's requirements and converted the STO from the LINGO mathematical programming language to AMPL.

New York State Electric and Gas Corporation | Total Fuel Management (TFM) System Development; Binghamton, NY

Developed a coal purchase optimization system for a total fuel management (TFM) system for New York State Electric and Gas (NYSEG) Corporation. The optimizer provided the capability to evaluate large numbers of coal purchase options while simultaneously accounting for system-wide and unit-specific constraints, coal delivery options, governmental regulations and inventory levels, as well as fuel purchase cost.

Black & Veatch| Optimal Generation Expansion Model Development; Kansas City, Mo.

Developed optimal generation expansion software program. The optimal generation expansion model (OGEM) is based on dynamic programming algorithms. The OGEM can simultaneously consider several expansion plans and automatically determine the most economical plans.

Virginia Power| Technology Overview Study; Richmond, Va.

Performed a study on the status of developing coal and gas based technologies for Virginia Electric and Power Company. The report generated from the study provided an unbiased overview of the status and potential use of developing coal and gas based electric generating technologies with respect to utility application. The four technology categories characterized were fluidized bed combustion technologies, fuel cell technologies, gas turbine based cycle technologies, and advanced coal based cycle technologies.

Testimony of
Andrew C. Byers

DIRECT TESTIMONY

OF

ANDREW C. BYERS

Table of Contents

I. Introduction and Qualifications

Q. Mr. Byers, please state your full name and business address.

A. My name is Andrew C. Byers. My business address is 11401 Lamar Avenue, Overland Park, KS 66211

Q. Please state your business position and responsibilities.

A. I am a Director of Environmental Services for Black & Veatch Corporation (Black & Veatch). In that role, I lead the Environmental Management Group which provides consulting and permitting services to clients in the energy sector. I have over 22 years of experience in preparing and supervising environmental impact assessments for major infrastructure projects in the power generation and oil & gas industries.

Q. Please summarize your educational background and your professional experience.

A. I graduated from the University of Missouri with a Bachelor of Arts degree in Speech Communication in 1979, and the University of Tulsa in Tulsa, Oklahoma with a Juris Doctor degree in 1982. I was admitted to the Oklahoma Bar in 1982 and the Missouri Bar in 1983. During the course of my career, I have acted as an environmental and energy attorney and consultant for the Missouri Department of Natural Resources and several companies. My expertise lies in environmental regulation, assessments, and permitting for major infrastructure projects both domestically and internationally. I

have participated in numerous environmental impact assessments in support of both the regulatory and applicant roles. A copy of my CV is included as Schedule ACB-1.

Q. Have you previously testified before the Rhode Island Public Utilities Commission?

A. No, I have not.

Q. Are you sponsoring any schedules?

A. Yes. I am sponsoring the following schedules:

Schedule ACB-1	CV of Andrew C. Byers
Schedule ACB-2	Black & Veatch Report, "Environmental Impact Review Summary of Proposed New England Energy Infrastructure"

II. Summary of Testimony and Schedules Sponsored

Q. Please describe your responsibilities in this proceeding.

A. On October 23, 2015, The Narragansett Electric Company d/b/a National Grid (National Grid) issued a Request for Proposal entitled "Natural Gas Capacity, Liquefied Natural Gas , And Natural Gas Storage Procurement" (the RFP). I directed Black & Veatch environmental professionals concerning the evaluation of the environmental impacts of the proposed pipeline project to ecological resources in the State of Rhode Island, as well as environmental impacts to regional natural resources in the New England states. In my testimony, I am sponsoring the report titled,

"Environmental Impact Review Summary of Proposed New England Energy Infrastructure," included as Schedule ACB-2. Black & Veatch's report focuses on the potential environmental impact of the proposed Access Northeast (ANE) Project to environmental resources in the State of Rhode Island, as well as regional air quality, groundwater, and protected wildlife resources.

Q. Could you please describe how the ANE Project will impact emissions in the New England Region?

A. Based on Black & Veatch's modeling assessment, as presented in Schedule ACB-2, the increased availability of firm natural gas supply and capacity resulting from the development of the ANE project will reduce regional gas and electric prices, as well as increase the dispatch of natural gas versus other fuels. The increased dispatch of natural gas-fired over coal- and oil-fired power generation will yield an overall reduction in regional sulfur dioxide (SO_2), oxides of nitrogen (NOx), and carbon dioxide (CO_2) emissions. Black & Veatch's analysis indicates that, relative to the Base Case scenario (status quo absent the proposed ANE project), the addition of ANE [redacted] in the New England region.

Q. Please explain how the ANE Project will minimize impacts to water resources.

A. The ANE Project will include development of a number of plans and procedures to manage and minimize impacts to regional groundwater and surface water resources. These plans will include, but are not limited to, a Stormwater Pollution Prevention Plan, a project-specific Upland Erosion Control, Revegetation, and Maintenance Plan, a project-specific Wetland and Waterbody Construction and Mitigation Procedures, a Spill Prevention Control and Countermeasures Plan, and a Horizontal Directional Drill Plan. All of these plans will be included in the FERC application for a Natural Gas Act Section 7(c) Certification. Implementation of these plans and procedures will minimize adverse impacts to regional water resources.

Q. Please explain how the ANE Project will minimize impacts to endangered species.

A. Potential impacts to protected, threatened or endangered species and their habitats along the pipeline will be minimized and avoided through initial planning and routing efforts to identify areas where such species and their habitat are documented or observed from preliminary field surveys. Further consultations with the US Fish and Wildlife and state wildlife resource agencies will be undertaken to determine the potential presence of federally- or state-listed rare, threatened or endangered species or their designated critical habitats for the final pipeline route, and follow-up pedestrian surveys will be undertaken to confirm the presence or absence of these species and habitats. If field surveys observe rare, threatened or endangered species or their

critical habitat, appropriate avoidance and mitigation measures will be developed in consult with the US Fish and Wildlife and state wildlife resource agency, and implemented.

Q. Please describe any impacts that will be specific to Rhode Island.

With regard to those aspects of the proposed project to be situated within Rhode Island, the ANE Project includes a proposal to upgrade an existing Algonquin Gas Transmission Company LLC (Algonquin) compressor station located in Burrillville, Rhode Island. This upgrade will include retirement and replacement of three existing reciprocating internal combustion engine compressors with two new natural gas-fired Solar Taurus turbine compressor units. The compressor upgrades will be considered a modification of an existing stationary source of air emissions by Rhode Island Department of Environmental Management Office of Air Resources. Therefore a pre-construction air permit will be required prior to commencing construction. As such, the permit will require the project to be designed and operated in a manner consistent with the requirements of the EPA-approved Rhode Island State Implementation Plan (State Implementation Plan). The State Implementation Plan is designed to maintain and/or improve the air quality of the state. Where appropriate, the project will be designed with air emission controls as necessary to achieve compliance with state and federal air regulations in order to comply with ambient air quality standards as outlined in the State Implementation Plan.

Because the compressor station upgrade modifications will occur within the fence line of an existing developed/disturbed site, construction and operational activities is not likely to have direct adverse impacts to groundwater, threatened and endangered species, wetlands, land use and community, and cultural resources in Rhode Island.

National Grid will verify that each replacement compressor unit will comply with the FERC noise standard of Ldn [day-night sound level] of 55 dBA [decibels on the A-weighted scale] at noise sensitive areas following installation. If the noise attributable to operation of any of the replacement compressor units exceeds 55 dBA Ldn at any noise sensitive areas, additional noise controls will be implemented to achieve the regulatory level of 55 dBA Ldn.

III. Conclusion

Q. Does this conclude your pre-filed testimony in this proceeding?

A. Yes. It does.

Schedule ACB-1
Curriculum Vitae

Andrew C. Byers

Andrew C. Byers, Associate Vice President currently serves as Director of Environmental Services section for Black & Veatch's Energy Business. His position involves the management of licensing and environmental services, primarily for the electric utility and public works industries. Principal responsibilities include the identification and analysis of applicable local, state, federal, and international environmental laws; coordination of project siting and permitting efforts; client consultation and representation with regulatory agencies; evaluation of environmental impact, mitigation, and remediation issues; and preparation of advisory memoranda to assist project personnel. He also serves as Black & Veatch Energy's Regulatory and Legislative Policy Advisor, responsible for tracking developments and advising on risks and opportunities arising from key federal legislative, regulatory, and judicial initiatives.

AVP DIRECTOR OF ENVIRONMENTAL SERVICES

Expertise:
Agency Consultation and Negotiations; Environmental Impact Investigations and Analysis; Permitting Assessment Strategy and Execution; Public Hearing Presentations and Testimony; Regulatory and Legislative Policy Advisor

Education
Juris Doctor, Energy and Environmental Law, University of Tulsa, 1982, United States
Bachelor of Arts, Speech Communication, University of Missouri at Columbia, 1979, United States

Professional Registration
License, Attorney No. 30184, Missouri Bar Association, 1983

Total Years of Experience
32

Black & Veatch Years of Experience
23

Professional Associations
Missouri Bar Association - Member

Language Capabilities
English
Spanish

Office Location
Overland Park, Kansas, USA

PROJECT EXPERIENCE

Wisconsin Power and Light; Columbia Energy Center Air Quality Control Retrofit; Wisconsin, United States; 2011-In-Progress

Permitting Project Manager - Black & Veatch. Managed environmental permitting efforts alongside conceptual design development in support of authorizing installation of air quality control systems on the nominal 1,054 MW subbituminous coal fired Columbia Energy Center power station. Air quality control systems included two spray dryer absorbers and fabric filter baghouses, expansion of the existing activated carbon injection system, and associated lime, powdered activated carbon, and ash storage and handling equipment. Permit applications were prepared and authorizations obtained for state air construction permit, state wastewater treatment and storm water discharge permits, state and county banks and shorelands development permits, local development and erosion control permits, and various project approval requests from the Federal Aviation Administration (FAA) and state historic preservation office.

European Bank for Reconstruction and Development (EBRD); Ukraine Sustainable Energy Lending Facility (USELF) Strategic Environmental Review; Ukraine; 2011-2011

Environmental Subject Matter Expert - Black & Veatch. Prepared environmental impact assessment and policy analysis for development of EBRD financing for renewable energy projects in Ukraine. Contributed to preparation of the Strategic Environmental Review report assessing significance of potential impacts and recommending mitigation measures and policy revisions to enable programmatic development of various renewable energy (wind, solar, hydroelectric, biomass, and biogas) generation projects.

Xstrata Alloys; Lesedi Independent Power Producer (IPP) Power Plant; South Africa; 2010-2011

Environmental Manager - Black & Veatch. Provided consulting services in reviewing and advising development of a new IPP minemouth circulating fluidized bed (CFB) 600 MW electric generation plant. In conjunction with Owners Engineers services, provided assistance and support to Xstrata project management in identifying permitting coordination and planning issues. Assisted in coordination and review of local environmental consultant efforts in developing permitting plan; planning and oversight of specialist studies; and development of applications, scoping reports, environmental impact assessment reports, and environmental management plans. Performed other activities in support of obtaining Department of Environmental Affairs Environmental Authorization, Waste Act Permit, and Atmospheric License, and Department of Water Affairs Integrated Water Use License.

Kuyasa Mining (Pty) Ltd.; Kuyasa IPP Power Plant; South Africa; 2009-2011

Environmental Manager - Black & Veatch. Provided consulting services in evaluating the feasibility and site selection of a new IPP minemouth CFB 600 MW electric generation plant. In conjunction with Owners Engineers services, provided assistance and support in coordination and planning environmental permitting activities. Assisted in coordination and review of local environmental consultant efforts in developing permitting strategy, planning and oversight of specialist studies, and developing applications, scoping reports, environmental impact assessment reports, and environmental management plans. Performed other activities in support of obtaining Department of Environmental Affairs Environmental Authorization, Waste Act Permit, and Atmospheric License, and Department of Water Affairs Integrated Water Use License.

Tenaga Nasional Berhad (TNB); Manjung Expansion Feasibility Study; Malaysia; 2010-2010

Environmental Manager - Black & Veatch. Assisted in evaluating the technical, economic, and environmental feasibility of constructing a 2 x 1000 MW supercritical coal fired power plant expansion to the existing Sultan Azlan Shah power station. Working together with TNB and the Universiti Teknologi Malaysia (UTM), developed a Terms of Reference for assessing potential environmental impacts from the proposed development, including the cumulative impacts from the new and existing plants for submittal to the Department of Environment Putrajaya for its approval. Activities included site reconnaissance to identify environmental receptors and constraints, as well as to gather information on existing site conditions, infrastructure, and surrounding communities. Assisted in identifying all applicable national and international regulatory requirements, potential environmental and social impacts, and appropriate mitigation commitments in development of the environmental impact assessment (EIA), as well as coordinating project design and planning to achieve the applicable environmental performance standards and EIA commitments. Also evaluated potential eligibility for Clean Development Mechanism certification and generating carbon credits.

TAQA New World; Jorf Lasfar Power Plant Expansion; Morocco; 2010-2010

Project Manager - Black & Veatch. Provided professional environmental consulting services for the Jorf Lasfar Units 5 and 6 expansion project in Morocco. Conducted a review of correspondence between the project EIA consultant and project developer regarding the scope of investigations to be undertaken, as well as an initial draft EIA report, to assess its conformity with international guidelines and industry practices. Provided advice on what may be considered appropriate and reasonable industry practice based on company experience and involvement in numerous coal fired power plant projects in developing countries that required an EIA for host country authorization and/or financing purposes. A gap analysis report was provided on the conformity of the EIA with the International Finance Corporation (IFC), World Bank, and Equator Principles international standards and industry practices.

National Industrial and Commercial Investments Limited; Amaila Falls Hydroelectric Project; Guyana; 2010-2010

Environmental Manager - Black & Veatch. Supported technical engineering assessment of the proposed Amaila Falls hydroelectric project consisting of construction of a new dam structure just upstream of the confluence of the Amaila and Kuribrong Rivers, power conduit, and powerhouse. More specifically, provided technical advice and support in evaluating the project's potential eligibility for obtaining Clean Development Mechanism (CDM) credits under the Kyoto Protocol. An Environmental Asset Report (EAR) for CDM-certified emissions reductions was compiled identifying and evaluating project eligibility for CDM registration under the consolidated baseline methodology for grid-connected electricity generation from renewable sources. The EAR outlined barriers to attaining CDM registration, assessed project compliance with World Commission on Dams (WCD) social and environmental standards set forth under their new Hydropower Sustainability Assessment Protocol, and estimated potential project emissions reduction benefits.

Optim Energy; ArcLight Merger Acquisition Assessment; Nevada, United States; 2010-2010

Environmental Manager - Black & Veatch. Directed due diligence review of fossil fuel generation portfolio with an aggregate capacity of 1,590 MW located in Texas, Nevada, and New Mexico. Reviewed technical data from operations reports and maintenance records, and all major permits, reports, and audits to address air emissions, water supply, wastewater, solid and hazardous waste, and greenhouse gasses regulated by the state and federal agencies. Interviewed corporate and plant environmental staff to determine the status of compliance and plans to address pending future regulatory requirements. Prepared report identifying key issues, risks, and opportunities relative to acquisition and future operation of subject assets.

Confidential Client; Valuation of Coal Power Assets; United States; 2010-2010

Environmental Project Manager - Black & Veatch. Performed an in-depth valuation assessment of current compliance, potential future regulatory requirements, and near-term compliance strategy of an IPP's fleet of 43 fossil-fuel fired units at 15 different power generation facilities. Reviewed permit conditions, existing state regulatory programs, and pending and proposed federal environmental regulatory programs to evaluate sufficiency of current operations and planned upgrades to meet expected compliance requirements and deadlines. Reviewed capital improvement plans regarding current and evolving air quality control, waste management, water intake and consumption, and wastewater treatment requirements, and produced an independent assessment report summarizing individual unit's environmental compliance capability and compliance strategies for prospective purchaser's review and consideration as part of the offering documents. Client subsequently decided to defer offering.

Amonix, Inc.; Southwestern Solar Power Generation; United States; 2010-2010

Project Manager - Black & Veatch. Performed an independent assessment of permitting requirements, plans, and strategies for development of 174 MW of new high concentration photovoltaic solar power generation on 12 different sites in California, Nevada, and Arizona for a Department of Energy loan guarantee. Identified environmental issues and permitting requirements associated with site disturbance; potential contamination; transmission line innerconnection; development in stream beds, wetlands, and/or floodplains; flood hazards; protected species and habitats; air quality impacts; visual and airspace navigation impacts; cultural or historical resources; land use and zoning authorizations; California Environmental Quality Act compliance; and construction activities.

BC Hydro; Greenhouse Gas (GHG) Policy and Scenario Analysis; British Columbia, Canada; 2010-2010

Regulatory Manager - Black & Veatch. Performed a review and evaluation of established and emerging GHG policies, legislation, and regulations affecting jurisdictions into which BC Hydro sells electricity, to support modeling of potential carbon prices and impacts to future operations. Researched and summarized the current status of national GHG policies in Canada and the United States, regional policies in the Western Electricity Coordinating Council (WECC) being developed under the Western Climate Initiative, and individual policies of British Columbia and all US states in the WECC. The findings were ultimately incorporated into a study report that quantified the GHG emissions effects from switching fuel from electricity to natural gas in the residential and small commercial sectors in British Columbia and its sufficiency to meet four different GHG reduction targets by 2020.

Eskom; Coal 3 Feasibility Study; South Africa; 2008-2010

Environmental Manager - Black & Veatch. Provided consulting services to facilitate reviewing and evaluating the feasibility of the development of a 6 x 800 MW coal fired power plant to be located in the Waterburg District of Limpopo Province in South Africa. Provided assistance and support to Eskom project management in identifying permitting coordination and planning issues. Consulted directly with national and provincial agencies to confirm applicable permitting requirements and application review processes. Developed a permitting plan that outlined legal requirements; all permits and approvals needed from national and provincial agencies for construction and operational activities; technical and environmental data needed to prepare and support application submittals; and management tools, including a permitting schedule, to identify the duration and breadth of effort required for obtaining each permit approval.

Bahamas Ministry of Environment; Fresh Creek Andros Sustainable Land Use Study; Bahamas; 2009-2009

Project Manager - Black & Veatch. Performed a review of government land holdings in the Fresh Creek area of Andros Island to recommend a balance of economic, environmental, and community interests to accommodate sustainable future development. Conducted an inventory of the natural resources in and around the subject holdings through field studies of existing physical and ecological resources, gathering data on terrestrial and marine flora and fauna and surface and groundwater resources, and observing existing land uses. Assessed capacities of existing island utilities and infrastructure and conducted stakeholder consultations with government agencies, town officials, nongovernmental organizations (NGOs), and island residents regarding natural, cultural, and socioeconomic conditions and concerns relative to potential future development of the Hotel Corporation of the Bahamas (HCB) land holdings. Produced a report categorizing the subject land holdings into six areas or "zones" based on similar background conditions and common features for potential future development for legislative consideration and debate.

Bahamas Ministry of Environment; Bimini Bay Compliance Assessment; Bahamas; 2008-2009

Project Manager - Black & Veatch. Conducted an impartial, independent evaluation of the Bimini Bay Project to identify the extent to which the government of the Bahamas previously approved individual aspects of ongoing project development; evaluated the extent to which existing development activities had been addressed in the environmental assessment (EA) and management plan submittals and the extent to which environmental degradation occurred beyond that described in these environmental submittals; and assessed the island capacity to accommodate changes in the latest proposed project land use plans. Reviewed documents, conducted interviews, and performed a site visit to investigate and audit the extent of project development, construction activities, and existing site conditions. Prepared a gap analysis report summarizing its compliance analysis and findings and presented its findings to the Ministry of Environment, Bimini Town Council, and NGOs, as well as to the general public in an open meeting forum.

Interstate Power & Light; Sutherland Unit 4 Coal Plant Permitting; Iowa, United States; 2006-2009

Project Manager - Black & Veatch. Managed environmental studies and conceptual design development in support of permitting a 648 MW pulverized coal power generation facility located in Marshalltown, Iowa. Activities included preparation of all permit applications, including Utility Board certification; US Army Corps of Engineers wetlands permit; state Prevention of Significant Deterioration (PSD) air construction permit; floodplain development permit; wastewater treatment facility permit; wastewater and storm water discharge permits; and various project approval requests from the Federal Aviation Administration (FAA), United States Fish and Wildlife Service (USFWS), state historic preservation office, and other miscellaneous state and local permit applications. Provided expert testimony in Utility Board hearings and participated in public informational meetings.

City of Mission; GHG Inventory; Kansas, United States; 2008-2008

Environmental Manager - Black & Veatch. Provided professional services in defining the basic concepts and goals of GHG inventories and assisting the city in conducting a GHG inventory utilizing the Clean Air and Climate Protection (CACP) software program. Researched and outlined the features and capabilities of the CACP software and how the city's GHG emissions should be categorized and inventoried based on municipal operations (government) and activities occurring within the city limits (community). Established organizational boundaries for both the government and community inventories and identified CACP software data sources and input needs. Collected and categorized data on fuel and energy consumption, as well as residential, commercial, industrial, transportation, and waste generation activities resulting in or associated with direct or indirect GHG emissions. Reviewed collected data for sufficiency and reliability to determine by how far back in time reliable data could be recovered. Data were then input into the CACP software to produce initial inventory results. Program outcomes were then reviewed for quality assurance, reliability, and reasonableness, and additional runs were performed with data adjustments and sensitivity cases to refine the inventory results. A written report was prepared, and results were presented to the City Sustainability Committee.

Intermountain Power; GHG Compliance Study; Utah, United States; 2008-2008

Environmental Manager - Black & Veatch. Managed a feasibility study analyzing options for reducing GHG emissions to comply with California emissions performance standards and cap-and-trade program requirements. Evaluated various generation options for technical and economic viability, including co-firing biomass or natural gas, solar eternal feedwater heating, solar thermal power, geothermal feedwater heating, geothermal power, wind, hydroelectric, and anaerobic digestion. Provided detailed regulatory and economic analysis of existing and proposed international, national, regional, and state GHG trading programs. Provided analysis of geologic sequestration potential and review of legal and regulatory barriers to near-term implementation.

MPX; Power Generation Portfolio Initial Public Offering (IPO); Global; 2007-2007

Environmental Manager - Black & Veatch. Performed a review of a portfolio of power generation development projects wholly or partially owned by MPX in support of its IPO memorandum. Performed a technical evaluation of major environmental aspects of approximately 5,000 MW of hydroelectric, coal fired, gas fired, and diesel power generation projects located in Brazil and Chile. A written technical report was prepared for inclusion with the IPO memorandum that addressed each project's ability to achieve compliance with all applicable host country and international banking air pollutant emissions, wastewater discharge, and ambient noise regulatory requirements; summarized the status of obtaining all preliminary, construction, and operational environmental licenses, permits, and approvals; and outlined the commitments and costs of all mitigation and monitoring measures to be implemented during the construction and operation of each project.

TransAlta; Multipollutant Compliance Assessment; Alberta, Canada; 2006-2006

Environmental Manager - Black & Veatch. Performed an assessment of the technical and economic feasibility of installing new emissions control equipment to achieve compliance with impending provincial and national regulatory programs requiring reductions of mercury (Hg), oxides of nitrogen (NOx), sulfur dioxide (SO2), and carbon dioxide (CO2) emissions. Researched and summarized the framework and requirements of the new emissions trading and coal fired power plant regulations, as well as considerations and options for strategic compliance. Identified commercially viable technologies that could feasibly reduce emissions of the target compounds and estimated the associated achievable emissions reduction, capital, and operations and maintenance (O&M) costs for each. The identified alternatives were combined to create compliance scenarios targeting reduction of multiple emissions.

Companhia Vale do Rio Doce; Moatize Power Plant; Mozambique; 2006-2006

Environmental Manager - Black & Veatch. Provided technical and consulting services in support of the development of a 3 x 500 MW minemouth coal fired power plant in northern Mozambique. Prepared an enterprise characterization to support the filing of a Prefeasibility Environmental Study (EPDA) to the Ministry for Coordination of Environmental Affairs (MICOA) as part of the EIA approval and permitting process. Also prepared a Bankable Feasibility Study (BFS) that provided an independent evaluation of the power plant's ability to achieve and maintain compliance with applicable environmental performance standards, and to fulfill commitments to address and manage potentially significant environmental impacts, throughout the life of the project.

Coal Investment Corporation; Mmamabula Coal Plant; Botswana; 2006-2006

Environmental Manager - Black & Veatch. Assisted and supported the development of EIA reports for a proposed 6 x 600 MW minemouth coal fired power plant, transmission lines, and associated facilities in southeastern Botswana. Provided conceptual design data and environmental support, including performing the air dispersion modeling of exhaust stack and fugitive emissions from the power plant, and provided local environmental consultants with design and operational data, practices, and plans for incorporation into the EIA studies on potential impacts, mitigation, and monitoring measures.

Confidential Client; Generation Assets Due Diligence; Texas, United States; 2006-2006

Environmental Manager - Black & Veatch. Assessed 14 separate gas and oil fired generation facilities located throughout a designated utility service territory in Texas. Reviewed technical data from operations reports; outage logs and maintenance records; all major permits, reports, and audits addressing air emissions, water supply, wastewater, solid and hazardous waste, drinking water, and polychlorinated biphenyl (PCBs); and hazardous substances as regulated by the state and federal agencies. Interviewed corporate and plant environmental staff to determine the status of compliance and plans to address pending future regulatory requirements.

Confidential Client; Environmental Compliance Assessment; Texas, United States; 2006-2006

Lead Environmental Auditor - Black & Veatch. Performed an environmental compliance assessment of 11 natural gas fired generating facilities in Texas. The environmental review examined current and past compliance with all applicable permit conditions and regulatory programs, as well as estimating costs of complying with proposed or pending future environmental regulatory programs. The assessment included extensive records review and interviews of environmental managers at the plant and corporate levels. Reports were prepared to support the client's strategic decision-making efforts with regard to future plant operations.

First Reserve Corporation; GHG Emissions Reduction Credit Portfolio Valuation; United States; 2006-2006

Project Manager - Black & Veatch. Performed a portfolio review of GHG emissions reduction credits held by Blue Source and evaluated its potential acceptance for trading in various proposed future credit trading regimes in the United States. The emissions reduction credits were evaluated based on the type of reduction project, vintage, geographic location, ownership, baselines, and reductions verification and monitoring as determined from the documentation provided for review. A report was prepared that (1) summarized the evolution of GHG trading and generally recognized criteria for reduction credits to be recognized as a creditable trading commodity, (2) identified current and potential future GHG reduction credit trading programs in the United States, and (3) evaluated the potential marketability of the subject emissions reduction credits and the risks and uncertainties regarding their future use and value for trading in the United States under various proposed regulatory regimes.

Florida Power & Light Company (FPL); Clean Air Interstate Rule (CAIR) Study; Florida, United States; 2006-2006

Project Manager - Black & Veatch. Directed a planning study to determine the regulatory impacts and compliance solutions for implementation of the proposed CAIR in Florida. Researched emerging regimes proposed by the Florida Department of Environmental Protection for initial and future allocations of annual NOx and SO2 and seasonal NOx allowances for affected generating facilities in the state and conducted modeling to project allowance prices for use in evaluating and identifying cost-effective control technology options. Developed design criteria and capital and O&M cost estimates for all the potential emissions control technologies that could be physically installed at each of 92 existing and planned future units regulated under the CAIR. Applied an internal linear optimizer analytical tool to identify and recommend the most cost-effective mix of control equipment retrofit projects to achieve the necessary reductions to enable FPL to limit its emissions to an amount equal to its projected allowance allocations in the future.

Allegheny Energy Supply; Hatfield's Ferry and Fort Martin Air Quality Control Upgrades; Pennsylvania, United States; 2005-2005

Project Manager - Black & Veatch. Prepared a permitting assessment report summarizing the major environmental permitting requirements and subsequently managed the preparation of permit application packages to authorize construction and installation of limestone forced oxidation flue gas desulfurization (FGD) air quality controls on the existing coal fired units at Hatfield's Ferry and Fort Martin Power Plants. Multiple federal, state, and local permit applications were submitted for the proposed FGD upgrades and associated plant modifications to accommodate the construction and operation of new barge facilities on the Monongahela River, new limestone and gypsum handling facilities, and construction of a new multiflue exhaust stack.

Louisville Gas & Electric; Trimble County Unit 2 Cumulative Environmental Assessment; Kentucky, United States; 2005-2005

Project Manager - Black & Veatch. Performed analysis and prepared a Cumulative Environmental Assessment (CEA) report for submittal to the Kentucky Environmental and Public Protection Cabinet (KEPPC) in support of development of a new coal fired unit (Unit 2) at the existing Trimble County power generation facility. The CEA, a prerequisite to all other state permitting, assessed potential impacts to existing air quality, water quality, waste management, and water use / consumption potentially arising from the construction and operation of the proposed coal fired 750 MW Unit 2 addition. It was the first CEA approved by the KEPPC.

Tyr Energy; Green Country Asset Valuation; Oklahoma, United States; 2004-2004

Environmental Manager - Black & Veatch. Performed a due diligence and asset valuation review of an 800 MW gas fired combined cycle combustion turbine plant located south of Tulsa, Oklahoma, in support of an acquisition bid. Conducted a pedestrian site visit; interviewed plant staff and management; reviewed operating documents, records, and permits; and consulted with regulatory agencies to assess current asset condition and compliance capabilities and to identify and project any future operating constraints or major expenditures that might be required or result from existing or proposed regulatory requirements.

Rural Utilities Service; Associated Electric Thomas Hill Life Extension Loan Review; Missouri, United States; 2004-2004

Environmental Manager - Black & Veatch. Performed a due diligence review of a coal fired steam electric generating plant located in central Missouri in support of life extension financing. Interviewed plant staff and management and reviewed environmental records and permits to assess continuing compliance capabilities and identify / project potential future operating constraints or major expenditures that might be required or result from existing or proposed regulatory requirements.

NRG; Generation Assets Refinancing; New Jersey, United States; 2004-2004

Project Manager - Black & Veatch. Assessed the costs and status of environmental compliance, liabilities, and risks under present and pending regulatory requirements for a portfolio of 65 units at 15 different plants. Assessed the likely impact of changes in regulatory requirements on the subject NRG assets considering concurrent changes and upgrades being made at the individual facilities. In addition to reviewing pending and proposed environmental regulatory programs and consultations with NRG to confirm the status of ongoing compliance related upgrades at each plant, an independent evaluation was performed and presented in a comprehensive written report of the costs of compliance measures and controls to be implemented at each of the subject facilities to achieve compliance with expected environmental requirements to be imposed during the financing review period (between 2005 and 2012).

CIT; RAMCO Miramar Due Diligence; California, United States; 2004-2004

Environmental Manager - Black & Veatch. Performed a due diligence risk assessment of a new 46 MW gas fired intermediate load combustion turbine plant development located in San Diego, California, in support of construction financing. Reviewed agency filings, environmental reports, and permit applications; interviewed developer and environmental consultants; and contacted regulatory agencies to assess the status of permitting efforts and requisite regulatory approvals for construction and startup of proposed current asset condition and compliance capabilities and to identify and project any future operating constraints or major expenditures that might be required or result from existing or proposed regulatory requirements.

Bahamas Environment, Science & Technology (BEST) Commission; Liquefied Natural gas (LNG) Terminal EIA Review; Bahamas; 2004-2004

Project Manager - Black & Veatch. Stationed in BEST's offices, directed technical review of proposed LNG terminal and pipeline project environmental impact assessment, environmental management and emergency response plans, hazard assessments, and site remediation and decommissioning submittals on behalf of the Government of the Bahamas in its official evaluation of the project, including recommendations for permit conditions and mitigation measures to reduce/minimize project impacts. Also supported and represented BEST in all its negotiations and interface with the project applicant, assisted in establishment of a regulatory regime covering the environment, health, and safety aspects of LNG development, and provided training and technical oversight to individuals within the BEST organization in furtherance of building staff capability necessary for continued environmental oversight of the LNG facilities.

Deutsche Bank Securities; Intergen Asset Valuation; Global; 2004-2004

Environmental Manager - Black & Veatch. Performed an environmental assessment and asset valuation review of seven gas fired combined cycle and cogeneration plants located in the Netherlands, United Kingdom, and Mexico, and four coal fired power plants located in Australia, China, and the Philippines in support of acquisition bidding. Reviewed operating documents, records, and permits; consulted with regulatory agencies to assess current asset condition and compliance capabilities and to identify and project any future operating constraints or major expenditures that might be required or result from existing or proposed regulatory requirements, including a CO2 trading program that was being launched in the European Union.

Rural Utilities Service; Oglethorpe Life Extension Loan Review; Georgia, United States; 2004-2004

Environmental Manager - Black & Veatch. Performed a due diligence review of two coal fired steam electric generating plants and one pump storage hydroelectric plant located in Georgia in support of life extension financing. Interviewed plant staff and management and reviewed environmental records and permits to assess continuing compliance capabilities and identify / project potential future operating constraints or major expenditures that might be required or result from existing or proposed regulatory requirements.

Tyr Energy; Wildflower Asset Valuation; California, United States; 2004-2004

Environmental Manager - Black & Veatch. Performed a due diligence and asset valuation review of two gas fired combustion turbine plants (combined 232 MW) located in southern California in support of acquisition bidding. Conducted pedestrian site visits; interviewed plant staff and management; reviewed operating documents, records, and permits; and consulted with regulatory agencies to assess current asset condition and compliance capabilities and to identify and project any future operating constraints or major expenditures that might be required or result from existing or proposed regulatory requirements.

Westar; Generation Planning and Compliance; Kansas, United States; 2003-2003

Senior Environmental Manager - Black & Veatch. Provided an analysis of current and proposed environmental laws, regulations, and legislative initiatives in development of an overall generation assets portfolio strategy to determine and improve long-term value under various future management and regulatory compliance scenarios. The analysis involved the identification and evaluation of environmental legislative and regulatory drivers, including multipollutant legislation proposals in Congress; a new ozone ambient air quality standard; a new fine particulate ambient air quality standard; mercury Maximum Achievable Control Technology (MACT) standards; new and proposed Clean Water Act Section 316b rules for intake structures; emerging water quality issues related to National Pollutant Discharge Elimination System (NPDES) permitting and water use allocations; revisions to combustion waste disposal standards under the Resource Conservation & Recovery Act of 1976 (RCRA); and impacts to beneficial reuse of plant waste products. The evaluation was used to prepare for federal New Source Review (NSR) enforcement action settlement negotiations.

Pharmaceutical Consortium; Central Utilities Plant; Puerto Rico (U.S.); 2003-2003

Project Manager - Black & Veatch. Managed an environmental assessment and feasibility study for the development of an oil fired combustion turbine combined cycle cogeneration facility to provide steam and power to a consortium of five large pharmaceutical manufacturing facilities in Puerto Rico. The project involved performing environmental field studies, preliminary impact analyses, and conceptual design development; routing offsite utilities and interconnections to participating facilities; and identifying regulatory and community challenges to the development of the project.

NRG; Generation Assets Refinancing; Minnesota, United States; 2003-2003

Senior Environmental Manager - Black & Veatch. Assessed costs and status of environmental compliance, liabilities, and risks under present and pending environmental regulatory programs and initiatives in support of a bankruptcy refinancing review for a portfolio of 65 units at 15 different plants.

Excelon; Termoelectrica del Golfo Due Diligence; Mexico; 2003-2003

Senior Environmental Manager - Black & Veatch. Identified applicable lender and national environmental requirements, confirmed status of all permits and approvals, and provided findings and recommendations for maintaining future compliance in support of the acquisition and startup of a petroleum coke fired power plant in Mexico.

USTDA; Nuh Energy; Turkey; 2002-2002

Senior Environmental Manager - Black & Veatch. Identified and evaluated potential environmental impacts and licensing requirements for development of a 120 MW combined cycle power plant located adjacent to the Maramara Sea in Kocaeli Province, Turkey. Directed a local environmental consulting firm in identifying environmental issues, conducting field studies and technical analyses, and coordinating conceptual design. Identified applicable Turkey, World Bank, and US Export Import Bank environmental standard and licensing requirements, provided a preliminary EIA, and recommended appropriate mitigation and monitoring measures in a feasibility report funded by the USTDA.

US Trade and Development Agency (USTDA); Rainbow Millennium Circulating Fluidized Bed (CFB) Power Plant Project; South Africa; 2002-2002

Senior Environmental Manager - Black & Veatch. Identified and evaluated potential environmental impacts and licensing requirements for the development of a waste coal fired 240 MW CFB power plant in Richards Bay, KwaZulu-Natal, South Africa. Directed a local environmental consulting firm in identifying environmental issues, conducting field studies and technical analyses, coordinating conceptual design, and developing permitting and public involvement strategies for licensing the first privately developed and operated power generation facility in South Africa. The evaluation and recommendations were incorporated into a feasibility report funded by the USTDA.

Korean Development Bank; Southern Company Yulchon Power; South Korea; 2002-2002

Senior Environmental Attorney - Black & Veatch. Provided due diligence review of environmental and licensing issues for development of a new LNG fired 500 MW combined cycle power generation facility in Yulchon, Korea. Identified applicable Korean, World Bank, and Asian Development Bank environmental standards and licensing requirements; provided a preliminary EIA; and recommended appropriate mitigation and monitoring measures.

AmerenUE; Value Creation Generation Planning; Missouri, United States; 2002-2002

Senior Environmental Manager - Black & Veatch. Provided an analysis of current and proposed environmental laws, regulations, and legislative initiatives in the development of overall generation assets portfolio strategy to assess and improve long-term value under various future management and regulatory compliance scenarios, including the evaluation of compliance options for cooling water intakes.

Confidential Client; Coal Plant Permitting; United States; 2001-2002

Project Manager - Black & Veatch. Managed environmental studies and conceptual design development in support of permitting a pulverized coal minemouth 1,500 MW zero discharge power generation facility located in the Midwestern United States. Activities included preparation of all permit applications, including the PSD air permit; a Joint Permit Application concerning project related impacts to wetlands and cooling water river intake; nationwide US Army Corps of Engineers application; storm water permit and various project approval requests from the FAA, the USFWS, state historic preservation office, and other miscellaneous state and local permit applications.

Morgan Stanley Dean Witter; Randolph County Power Project; Alabama, United States; 1999-2002

Project Manager - Black & Veatch. Managed all permitting and related engineering and field study activities for development of a 1,500 MW combined cycle merchant power plant. Initial activities included the preparation and management of a licensing assessment and strategy; management of environmental field studies, site selection study, and pipeline routing and licensing study; transmission line risk analysis and environmental field studies; and Phase I environmental site assessment. Directly consulted with federal, state, and local agencies and officials; represented the client at public meetings; and managed all permitting activities. Permits and approvals for air emissions, water withdrawal, wastewater discharge, storm water discharges, and wetland disturbances for the plant site were obtained, as well as for associated pipeline and transmission line routes.

Williams Energy Marketing & Trading; Fulton Energy Center; Georgia, United States; 2001-2001

Project Manager - Black & Veatch. Managed the permitting and strategic development of a 1,230 MW combined cycle power generation facility in the south Atlanta metropolitan area. Activities included consultation with federal, state, and local environmental permitting agencies; development and presentation of a public relations program; and directing conceptual design of the power plant facility. Extensive environmental studies were performed for noise, wetlands, protected species, cultural resources traffic, local air quality, and visual impacts, as well as for a cemetery relocation. An environmental impact report was submitted in support of a zoning application. A PSD / NSR air permit application was prepared for an ozone nonattainment area.

Dominion Energy / Peoples Energy; Elwood Energy Center; Illinois, United States; 2000-2001

Project Manager - Black & Veatch. Managed the permitting for the conversion of a 1,500 MW simple cycle plant into a 2,500 MW combined cycle plant. Permit applications were prepared and submitted for water intake and discharge structures, surface water withdrawal, wastewater discharge, water and effluent pipelines, water quality certification, wetlands disturbance, storage reservoir (including dam safety), air quality, and county zoning. The client ultimately decided to abandon conversion plans for financial reasons, and the pending permit applications were withdrawn.

Aquila Energy; Hurricane; Dominican Republic; 2000-2000

Environmental Manager - Black & Veatch. Provided an environmental risks assessment for Aquila Energy's asset valuation project in support of a bid to acquire power generation facilities being divested by Cogentrix. The primary environmental evaluator was an oil fired combined cycle facility under construction in the Dominican Republic.

US Agency for International Development (USAID) / Institute of International Education; Training Program; Indonesia; 1999-1999

Project Manager - Black & Veatch. Managed and presented an intensive 2 week training course to PT Perusahaan Umum Listrik Negara (PLN) administrative and plant personnel on environmental management practices at thermal power plants.

Columbia Electric; Grassy Point Energy Center; New York, United States; 1999-1999

Project Manager - Black & Veatch. Managed the permitting of a 550 MW combined cycle power plant under the New York Article X process. The project was located on a portion of a municipal landfill undergoing closure and utilized wastewater from a nearby treatment plant for makeup supply. Activities included consultation and coordination with all federal and state agencies and public interest groups; management of conceptual engineering in support of permitting; preparation of preapplication, stipulations, and formal application; management of environmental studies; coordination with project legal counsel; and representation of the project at hearings.

USTDA; Romen Ergo Cogeneration Feasibility Study; Romania; 1998-1999

Environmental - Black & Veatch. Managed an environmental compliance and impact assessment study for the development of a privately owned cogeneration plant to provide steam to the city central heating system and electricity to local customers and the national electricity grid. This included the identification, review, and evaluation of applicable national, European Union, and World Bank environmental standards and regulatory permitting and compliance requirements.

Marshall Municipal Utilities; TRI Study; Missouri, United States; 1998-1999

Licensing Attorney - Black & Veatch. Managed regulatory compliance study to provide small municipal power plant with a management strategy for addressing newly applicable toxic release inventory requirements.

Elektrocieplowni Bialystok; Facility Expansion Feasibility Study; Poland; 1998-1999

Licensing Attorney - Black & Veatch. Performed evaluation of environmental impacts and regulatory requirements for expansion of existing power generation station capacity. Options reviewed included addition of combined cycle combustion turbine, pulverized coal, and fluidized bed coal units.

City of Phoenix; Regulatory Compliance Excellence Program; United States; 1998-1999

Licensing Attorney - Black & Veatch. Managed regulatory compliance task team in identifying the applicable regulatory requirements and assessing and improving the City Water Services Department's ability to manage its environ-mental compliance responsibilities and initiative.

InterAmerican Development Bank; Uruguaiana Project; Brazil; 1998-1998

Licensing Attorney - Black & Veatch. Reviewed and evaluated environmental impact studies and permitting efforts for financing due diligence report on a new 600 MW gas and oil fired combined cycle power plant in Uruguaiana, Brazil, and natural gas pipeline originating in Argentina.

Houston Industries; Power Generation Wood River Project; Illinois, United States; 1998-1998

Licensing Attorney - Black & Veatch. Managed licensing of a 500 MW combined cycle cogeneration merchant plant.

Exxon; Tekirdag Coal Plant Feasibility Study; Turkey; 1998-1998

Licensing Attorney - Black & Veatch. Performed environmental impact and permitting evaluation for development of a 2 x 500 MW pulverized coal power plant on the Sea of Maramara shoreline. Assessed potential impacts to air quality, water quality, terrestrial and aquatic ecology, and ambient noise; and identified requisite permits.

Dominion Energy / Peoples Gas; Elwood Project; Illinois, United States; 1998-1998

Licensing Attorney - Black & Veatch. Identified and evaluated environmental and regulatory licensing issues as part of overall feasibility study for 1500-3000 MW combined cycle IPP project to supply Chicago metropolitan market. Follow on work included managing air quality impact and best available technology analyses for PSD construction permit applica-tion.

Nong Khae Project; Thailand; 1998-1998

Licensing Attorney - Black & Veatch. Supervised due diligence environmental licensing assessment of 120 MW small power producer project for financing approval.

Niagara Mohawk Power Corporation; Divestiture Asset Valuation; New York, United States; 1998-1998

Licensing Attorney - Black & Veatch. Performed environmental assessments of electric genera-tion facilities being considered for divestiture. Assess-ments involved evaluation of existing conditions, permits, compliance with current and pending regulatory require-ments, current and past environmental management practices, and contracted support activities. Provided valuation of assets and potential liabilities for each gen-eration station, and recommendations for environmental improvements.

Kingdom of Thailand National Energy Policy Office; Biomass Feasibility Study; Thailand; 1998-1998

Licensing Attorney - Black & Veatch. Provided environmental and regulatory input to feasibility study of implementing biomass fueled power generation projects as a variety of existing agricultural processing plants throughout Thailand.

ENERSUL UTE; Campo Grande Project; Mato Grosso do Sul, Brazil; 1998-1998

Licensing Attorney - Black & Veatch. Managed environmental consultant in preparation of an Environmental Impact Assessment (EIA), incorporate international environmental standards into EIA work, and coordinate with agencies and client to obtain preliminary and installation license for a 300 MW gas fired combined cycle power plant project.

Espirito Santo Centrais Electicas; Norte Capixaba Project; Espirito Santo, Brazil; 1998-1998

Licensing Attorney - Black & Veatch. Managed environmental con-sultant in preparation of an Environmental Impact Assessment (EIA), incorporate international environ-mental standards into EIA work, and coordinate with agencies and client to obtain preliminary and installation license for a 150 MW gas fired combined cycle power plant project.

Williams Communications; Fiber Optics Feasibility Study; California, United States; 1998-1998

Licensing Attorney - Black & Veatch. Identified and evaluated environmental per-mitting and impact study requirements for construction and installation of buried fiber optic cable between Sacramento and San Francisco, California. Report screened several routing options and provided permitting strategy, contacts, procedures, and applications.

USAID / Institute of International Education; Energy Training Program; Philippines; 1997-1997

Project Manager - Black & Veatch. Managed and presented an intensive 2 week training course to governmental agency and utility administrative and plant personnel on environmental management practices at thermal power plants.

Gulf Electric; Kui Buri IPP Project; Thailand; 1997-1997

Licensing Attorney - Black & Veatch. Provided counsel on permitting and environmental compliance issues.

GPU International; Sidi Krir EEA BOOT Proposal; Egypt; 1997-1997

Licensing Attorney - Black & Veatch. Provided information and guidance on environmental and licensing requirements for establishing a new power plant in Egypt.

Central Maine Power; Asset Divestiture Project; Maine, United States; 1997-1997

Environmental Attorney - Black & Veatch. Conducted an environmental evaluation of an independent engineer's report for divestiture of various thermal power generation facilities (e.g., combustion turbine, oil fired boilers, wood waste boilers). Identified potential environmental liabilities, compliance status, and cost estimates for addressing existing and upcoming environmental requirements for the utility seller to assist in the initial assets valuation prior to divestiture.

Marathon Haripur Proposal; Bangladesh; 1997-1997

Licensing Attorney - Black & Veatch. Provided information and guidance on environmental and licensing requirements for establishing a new power plant in Bangladesh.

Light Servicos de Elecridade; Rio Light IPP Project; Rio de Janeiro, Brazil; 1997-1997

Senior Environmental Manager - Black & Veatch. Managed a local environmental consultant in preparation of an EIA, incorporated international (World Bank) environmental standards into the EIA work, and coordinated with agencies and the client to obtain preliminary and installation licenses for a large (700 MW) thermal power plant project.

Stillwater Electric Utilities; Boomer Lake Station; Oklahoma, United States; 1997-1997

Licensing Attorney - Black & Veatch. Managed NPDES permit application and SWPPP preparation.

Zurn Industries; Rojana Cogen SPP Project; Thailand; 1997-1997

Licensing Attorney - Black & Veatch. Provided due diligence review of environmental and licensing issues.

Jacksonville Electric Authority; St. Johns River Power Park; Florida, United States; 1997-1997

Licensing Attorney - Black & Veatch. Coordinated and prepared annual report (independent engineering evaluation of plant conditions, operations, and planning).

Bank of Ayudhya Public Co., Ltd.; Saha Pathana Inter-Holding Public Small Power Producer (SPP) Project; Chonburi, Thailand; 1997-1997

Environmental Attorney - Black & Veatch. Provided a due diligence review of environmental and licensing issues for the development of a new
122 MW combined cycle combustion turbine power plant under the national SPP program. Analysis included compliance with Thailand environmental standards and licensing requirements, as well as World Bank guidance for financing purposes.

Sithe Energies; Banpoo Cogeneration SPP Project; Thailand; 1996-1997

Senior Environmental Manager - Black & Veatch. Managed and coordinated EIA studies and report, site environmental liability investigations, and environmental permitting for a 120 MW combined cycle cogeneration plant under the national SPP program.

Enova Energy; Siting Study; Nevada, United States; 1996-1997

Licensing Attorney - Black & Veatch. Identified and evaluated permitting and environmental issues associated with construction and operation of a proposed gas fired combined cycle power plant at 10 different sites in Clark County, Nevada.

Tri Energy; Ratchaburi IPP Project; Ratchaburi, Thailand; 1996-1997

Licensing Attorney - Black & Veatch. Provided counsel on permitting and environmental compliance issues.

Union Electric; Labadie Plant Title V Operating Permit; Missouri, United States; 1996-1996

Licensing Attorney - Black & Veatch. Performed regulatory review to identify applicable regulatory requirements for Title V permit application.

Sprint; Spectrum Environmental Site Assessments; Missouri, United States; 1996-1996

Licensing Attorney - Black & Veatch. Performed environmental site assessments to identify environmental risks associated with lease of lands for erection of communication towers.

Springfield City Utilities; Title V Air Operating Permit; Missouri, United States; 1996-1996

Licensing Attorney - Black & Veatch. Performed regulatory review to identify applicable regulatory requirements for Title V permit application.

PPG / Bayer; Cogeneration Project; West Virginia, United States; 1996-1996

Licensing Attorney - Black & Veatch. Evaluation of environmental and permitting requirements in support of a feasi¬bility study for construction and operation of a combined cycle cogeneration facility.

Gulf Electric; Sara Buri SPP Project; Thailand; 1996-1996

Licensing Attorney - Black & Veatch. Provided counsel on permitting and environmental compliance issues.

Entergy; Saltend Cogeneration Project; United Kingdom; 1996-1996

Licensing Attorney - Black & Veatch. Reviewed and evaluated permitting requirements and environmental studies necessary for construction and operation of a new combined cycle cogeneration facility.

City of Wyandotte, Michigan; Compliance Plan; Michigan, United States; 1996-1996

Licensing Attorney - Black & Veatch. Provided review and counsel in defense of enforcement action; drafted compliance plan for settlement purposes.

Alise Botany Bay Project; New South Wales, Australia; 1996-1996

Licensing Attorney - Black & Veatch. Coordinated and reviewed data for input to environmental statement report evaluating impacts of a new combined cycle power plant.

First Boston; Jamshoro Power Station; Pakistan; 1995-1996

Environmental Manager - Black & Veatch. Responsible for an environmental impact and compliance evaluation of an existing 4 x 250 MW gas and oil fueled power plant as part of an independent engineer's assessment for privatization commission. Identified potential environmental liabilities and cost estimates for bringing the facility into compliance with applicable World Bank guidance and general environmental management practices for national utility commission to assist in the initial assets valuation prior to divestiture.

City of Alexandria, Louisiana; Spill Prevention; United States; 1995-1996

Licensing Attorney - Black & Veatch. Responsible for investigation of oil storage issues and preparation of spill prevention plan.

Nevada Colorado River Commission; Southern Nevada Water System Facilities Improvements Project; Nevada, United States; 1994-1996

Licensing Attorney - Black & Veatch. Responsible for preparation of regulatory requirements manual; coordinating and obtaining all federal, state, and local permits; acquisition of federal and private properties; and supervision of environmental and real estate subcontractors for design and construction of improvements to the Las Vegas Valley water treatment and distribution system.

Ponca City Utility Authority; Ponca City Utility Authority Unit 2; Oklahoma, United States; 1993-1996

Licensing Attorney - Black & Veatch. Responsible for preparation of a Clean Air Act compliance evaluation, acid rain certification, and Title V plant environmental permits.

Oklahoma Municipal Power Authority; Ponca City Repowering Project; Oklahoma, United States; 1993-1996

Licensing Attorney - Black & Veatch. Responsible for coordinating and obtaining all necessary federal, state, and local permits for construction and operation of a combined cycle combustion turbine and heat recovery steam generator.

Kansas City Power & Light Company; Hawthorn Plant; Missouri, United States; 1994-1995

Licensing Attorney - Black & Veatch. Responsible for preparation of a regulatory requirements manual, and coordinating all federal, state, and local permits necessary for construction and operation of an ash pond and utility ash landfill.

US Department of Defense; Pentagon Renovation; Virginia, United States; 1994-1994

Licensing Attorney - Black & Veatch. Responsible for identifying all environmental permits necessary for construction of additional intake and outfall structures for heating and cooling plant.

Iatan Power Partners; Iatan 2 Plant; Missouri, United States; 1994-1994

Licensing Attorney - Black & Veatch. Responsible for coordinating permitting of utility ash landfill for proposed Iatan 2 plant.

Barclays Bank and Deutsche Bank; Gladstone Power Station; Queensland, Australia; 1994-1994

Environmental Manager - Black & Veatch. Responsible for an evaluation of environmental compliance capability of an existing 6 x 280 MW pulverized coal power plant as part of an independent engineer's assessment in preparation of divestiture of assets. The analysis included compliance with Queensland environmental standards and licensing requirements, as well as World Bank guidance. Also identified and evaluated potential environmental liabilities and estimated necessary remediation efforts.

Louisville Gas & Electric Company; Various Projects; United States; 1994-1994

Licensing Attorney - Black & Veatch. Responsible for preparation of report on regulation of hydrogen sulfide in natural gas pipeline supply in Missouri, Kentucky, Ohio, Indiana, and West Virginia.

Goldman, Sachs & Company; Financing Construction of Lignite Fired 250 MW Facility; India; 1994-1994

Licensing Attorney - Black & Veatch. Responsible for preparation of environmental impact and permitting portion of Bank Assessment Report.

Moapa Power Partners, Ltd.; Fluidized Bed Used Tire Fired 53 MW IPP / QF Facility; Nevada, United States; 1993-1993

Licensing Attorney - Black & Veatch. Responsible for evaluating past permitting efforts, and identifying and coordinating acquisition of all permits and licenses necessary for construction and operation.

State of Missouri; Jefferson City, Missouri, United States; 1988-1993

Associate General Counsel - Missouri Department of Natural Resources. Legal counsel to state agency responsible for environmental regulation, energy conservation, state parks administration, and historic preservation. Supported Director in legal and policy matters; reviewed and negotiated contracts; supported and filed enforcement actions and settlements; drafted administrative rulemakings; coordinated with Attorney Generals Office in litigation; conducted public hearings; served as administrative judge for dispute resolution.

Various Clients; Various Projects; Oklahoma, United States; 1982-1986

Title Attorney and Landman - Santa Fe Materials. Reviewed title and rendered opinions on ownership of rights for oil and gas exploration and production ventures; leased mineral rights; drafted and negotiated contracts; and coordinated all geologic, engineering, and legal work.

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. "US Environmental Regulatory Update." Western Electric Institute Spring Energy Symposium. March 2013

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Byers, Andrew C. "Environmental Regulations Update." Las Vegas, Nevada; RMEL Plant Management Conference. June 2012

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Byers, Andrew C. "Status of Environmental Regulatory Drivers for the US Utility Industry." Kansas City, Missouri; Black & Veatch Technology Conference. April 2012

Byers, Andrew C. "Environmental Policy Driving Evolution of the US Power Generation Industry." New York City; Black & Veatch Power Industry Briefing. February 2012

Byers, Andrew C. and Brian O'Neal. "Cross State Air Pollution Rule - Winners and Losers." Tucson, Arizona; Electric Utilities Environmental Conference. January 2012

Byers, Andrew C. "Coal Combustion Residues Management - Today, Tomorrow and Beyond." Loveland, Colorado; Rocky Mountain Electric League Spring Management Conference. May 2011

Byers, Andrew C. "Regulatory Options and Sustainable Solutions." Kansas City, Missouri; Black & Veatch Technology Conference. February 2011

Byers, Andrew C. "Regulatory Changes and Their Potential Impact on the US Electric Industry." Kansas City, Missouri. February 2011

Byers, Andrew C. "Optimizing Compliance Solutions in an Ever Changing Regulatory Environment." American Coal Council Webcast. February 2011

Byers, Andrew C. "Coal Combustion Residues Management." Tucson, Arizona; Electric Utilities Environmental Conference. February 2011

Byers, Andrew C. "Insights on the Boiler MACT Rule Proposal." Black & Veatch Webinar. May 2010

Byers, Andrew C. "US Electric Utilities 2010 Regulatory Outlook." Kansas City, Missouri; Black & Veatch Technology Conference. February 2010

Byers, Andrew C. "California First to Regulate Sulfur Hexafluoride Greenhouse Gas - Rest of Country to Follow?." Black & Veatch Solutions Magazine Volume 31. January 2010

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Byers, Andrew C. "Technology and Regulatory Developments in Carbon Capture and Sequestration." New York, New York; Wall Street Utility Group. September 2008

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Byers, Andrew C. "New Source Review - Status of Federal Reform Regulations." Lake Ozark, Missouri; Missouri Bar Annual Environmental Conference. July 2007

Byers, Andrew C. "Carbon Capture & Sequestration Regulatory, Permitting and Environmental Risks and Mitigation." Houston, Texas; Carbon Sequestration Development & Financing Summit Projects Risks Workshop. July 2007

Byers, Andrew C. "Greenhouse Gas Reduction 101." Overland Park, Kansas; Black & Veatch Technology Conference. February 2007

Byers, Andrew C. "Maximum Achievable Control Standards for Air Toxics." Lake Ozark, Missouri; Missouri Bar Annual Environmental Conference. July 2006

Byers, Andrew C. "Adding CO2 to Multi-Pollutant Planning." Washington, D.C; Electric Utilities Consultants Preparing for a Carbon Constrained Future Conference. June 2006

Byers, Andrew C. "New Clean Air Interstate & Mercury Rules." Kansas City, Missouri; Midwest AWMA Annual Environmental Conference. January 2006

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Byers, Andrew C. "Proposed 316(b) Cooling Water Intake Rules for Existing Power Facilities." Shreveport, Louisiana; Plant Design & Operating Committee Meeting. February 2003

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Byers, Andrew C. "Environmental Initiatives and Drivers Affecting Sustainable Power Generation Development in the United States." Brussels, Belgium; POWER-GEN Europe 2001 Conference. May 2001

Byers, Andrew C. "Developing a Greenhouse Gas Emissions Trading Program for the European Union - What Can be Learned from the United States' Experiments." Brussels, Belgium; POWER-GEN Europe 2001 Conference. May 2001

Byers, Andrew C. "EH&S Management Information Systems: The Right Choice for Your Company?." Brussels, Belgium; POWER-GEN Europe 2001 Conference. May 2001

Byers, Andrew C. "Engineering and Environmental Service Consultants - How to Utilize in Project Development." San Diego, California; Council of Industrial Boiler Owners NOx Control XVI Conference. March 2001

Byers, Andrew C. "Regulatory Initiatives to Control NOx Emissions from Power Generation Facilities, 1990 through 2000 and Beyond." Orlando, Florida; POWER-GEN International 2000 Conference Proceedings. November 2000

Byers, Andrew C. "Environmental Regulatory Developments Affecting the Energy Industry." San Diego, California; ESP's Annual User Group Meeting. November 2000

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Byers, Andrew C. "Recent Revisions of Power Plant Air Emission Guidelines and Their Influence on Future Power Project Developments in Europe." Frankfurt, Germany; POWER-GEN '99 Europe Conference Proceedings. June 1999

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Byers, Andrew C. "Evolution of Environmental Permitting in Thailand." China Global Power Magazine. July 1998

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Byers, Andrew C. "Managing a Successful Environmental Permitting Effort for a Power Generation Project Overseas." Washington, D.C; Electric Power Supply Association Environmental Managers Annual Conference. October 1997

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Schedule ACB-2
Environmental Impact Review

Environmental Impact Review Summary of Proposed New England Energy Infrastructure

PREPARED FOR

Narragansett Electric Company d/b/a National Grid ("National Grid")

MAY 2016

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BLACK & VEATCH STATEMENT

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In conducting our analysis, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilize in performing the analysis and making these projections follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.

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Glossary of Terms

ANE	Algonquin Access Northeast
APE	Area of Potential Impact
CAA	Clean Air Act. US federal law that regulates air emissions.
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CPP	Clean Power Plan.
dBA	Decibels on A-weighted Scale
EIA	U.S Department of Energy - Energy Information Administration.
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GACT	Generally Available Control Technology
GHG	Greenhouse Gas
HDD	Horizontal Directional Drill
hp	Horsepower
INGAA	Interstate Natural Gas Association of America
Ldn	Day-night Sound Level
LNG	Liquified Natural Gas
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NOx	Nitrogen Oxides
NSA	Noise Sensitive Area
NSPS	New Source Performance Standard
RACT	Reasonably Available Control Technology

RICE	Reciprocating Internal Combustion Engine
RIDEM	Rhode Island Department of Environmental Management
RGGI	Regional Greenhouse Gas Initiative
SCR	Selective Catalytic Reduction
SHPO	State Historical Preservation Office
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPCC	Spill Prevention, Control and Countermeasures
SWPPP	Stormwater Pollution Prevention Plan
USFWS	U.S. Fish and Wildlife Service
VOC	Volatile Organic Compounds

1.0 Executive Summary

On October 23, 2015, The Narragansett Electric Company d/b/a National Grid ("National Grid") issued a Request for Proposal ("RFP") for natural gas pipeline capacity, liquefied natural gas ("LNG"), and natural gas storage. Black & Veatch was retained by National Grid to provide an independent assessment of the proposed natural gas pipeline infrastructure's potential regional and statewide environmental impacts, consistent with the requirements of Rhode Island's Affordable Clean Energy Security Act of 2014.

Black & Veatch's environmental impact assessment focuses on the possible effect of the proposed Project on regional greenhouse gas (GHG) emissions from direct carbon dioxide (CO_2) emissions through stack exhaust at power generation facilities. This assessment also evaluates likely statewide impacts to ambient air quality in Rhode Island and the surrounding airshed as well other potential non-air environmental impacts to groundwater, threatened and endangered species, noise, wetlands, land use and community, and cultural resources that may likely result from construction and operation of the proposed Algonquin Access Northeast Project (ANE or Project).

The assessment was undertaken utilizing a hybrid quantitative/qualitative analysis based primarily on the data presented in the Project's pre-filing draft Resource Report 1 filed with the Federal Energy Regulatory Commission (FERC) in December 2015 (Docket PF16-1-000). The quantitative components are based on projected emissions as determined by power sector modeling analyses conducted by Black & Veatch to evaluate the economic costs and benefits of the propose pipeline project. The qualitative components are based on Black & Veatch's experience and expertise in evaluating the environmental impacts from similar energy infrastructure, as well as Black & Veatch's understanding of the level and extent of impact analyses and mitigation that will be developed as part of the FERC authorization to construct the Project under Section 7(c) of the Natural Gas Act (NGA) and abandon certain facilities under Section 7(b) of the NGA.[1]

Key Observations and Analysis Results

The development of ANE will reduce regional SO_2, NO_X, and GHG emissions from power generators in New England states

As stated in Black & Veatch's companion report, *Evaluation of Long-term Economic Benefits from Proposed Incremental Energy Infrastructure into New England*, the increased availability of firm natural gas supply and capacity resulting from the development of the ANE project will reduce regional gas and electric prices, as well as increase the dispatch of natural gas versus other fuels. The increased dispatch of natural gas-fired over coal and oil-fired power generation will yield an overall reduction in regional sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and carbon dioxide (CO_2) emissions over the evaluation period.

[1] Per draft Resource Report 1 Appendix D1 Public and Agency Participation Plan, the remainder of draft Resource Reports 2 through 9 are scheduled to be filed in June 2016. Final Project Resource Reports 1 through 10 are to be included in the FERC Certificate Application package scheduled to be filed in November 2016

Our analysis indicates that, relative to the Base Case scenario (i.e. status quo absent the proposed ANE project), the addition of ANE would reduce NO_X emissions by approximately 18,000 tons, SO_2 emissions by approximately 35,000 tons, and CO_2 emissions by 6,000,000 tons in the New England region.

ANE has a limited direct environmental impact in Rhode Island.

Specific to project activities in Rhode Island, ANE is proposing to upgrade an existing Algonquin compressor station located in Burrillville, Rhode Island. The upgrade consists of the retirement of three existing reciprocating internal combustion engine (RICE) compressors and their replacement with two new natural gas-fired Solar Taurus turbine compressor units. This station modification will have a limited direct environmental impact in Rhode Island.

Air emissions will be controlled and limited through utilization of low NO_x burners and increased thermal efficiencies. Noise analyses will be conducted to evaluate the potential environmental noise impacts at nearby noise sensitive areas ("NSAs"), and appropriate noise mitigation measures will be incorporated into Project design. Additionally, the ANE project developer plans to conduct noise surveys to verify that the noise attributable to operation of the two replacement compressor units will comply with FERC requirements.

Construction will occur within the existing compressor station property, and therefore potential impacts to surface and groundwater resources, as well as protected species and cultural resources are unlikely and can be readily mitigated and managed within the existing site.

2.0 Regional Environmental Impacts

Air Quality

The Northeastern United States has had regional difficulty in attaining the National Ambient Air Quality Standards (NAAQS) for ground level ozone for decades. Historically, the combustion of coal and fuel oil in industrial, commercial, and residential applications has contributed to this difficulty. States with areas not attaining the ozone NAAQS (ozone non-attainment areas) are obligated under the Clean Air Act (CAA) to institute measures to mitigate the precursor pollutants that form ozone (i.e., NO_X and VOC) with the goal of eventually bringing the non-attainment area back into attainment with the NAAQS. One such measure available to states is known as Reasonably Available Control Technology (RACT). States implement RACT standards in order to control and reduce non-attainment pollutant emissions from existing sources.

Recently, the United States Environmental Protection Agency (EPA) finalized a new, more stringent ground level ozone NAAQS. EPA projections indicate that many areas along the I-95 corridor from the Mid-Atlantic region into New England, including portions of Rhode Island, could be designated as non-attainment areas under the 2015 ozone NAAQS. As such, it is feasible that states such as Rhode Island could increase the stringency of their RACT standards for NO_X and VOC emissions in an effort to reduce these emissions and bring the state's non-attainment areas back into attainment with the NAAQS. More stringent RACT standards could prompt operators of utility and industrial sources to shift from higher emitting fuels such as distillate fuel oils and coal towards lower-emitting natural gas, especially where the economics of switching to natural gas would be more cost-effective than the cost of additional emission control equipment that would otherwise be needed to meet RACT emission limits. Incremental natural gas transportation infrastructure in New England (i.e. ANE) could accommodate such potential fuel switching to aid in compliance with ground-level ozone NAAQs.

In addition to improving ground-level ozone conditions, utilization of additional natural gas supplies can provide co-benefits with regard to other regulated air pollutant emissions. For example, recently finalized federal environmental regulations addressing emissions of hazardous air pollutants (mercury, acid gasses and metallic air toxics), including the Mercury and Air Toxics Standards (MATS) and the Industrial Boiler Maximum Achievable Control Technology (MACT) and Generally Available Control Technology (GACT) standards, recognize the environmental benefits of natural gas-fired sources as they either exclude natural gas-fired units from being regulated under the rules entirely (MATS and Industrial Boiler GACT) or include only work practice standards (Industrial Boiler MACT) for natural gas-fired units.

Greenhouse Gases

Combustion of natural gas produces nearly 50 percent less carbon dioxide (CO_2) emissions than the combustion of other fossil fuels such as coal and distillate fuel oil. The increased availability of natural gas will provide more opportunities for many stationary sources in the region to switch from higher emitting fuels to reduce their CO_2 emissions. Moreover, greater availability of natural gas and lower gas prices resulting from increased gas pipeline capacity will render natural gas-fired assets more attractive from an economic standpoint

relative to coal and oil-fired generators. As such, dispatch of natural gas-fired power plants is projected to increase. These effects will be beneficial for achieving and maintaining compliance with air emissions programs such as the Regional Greenhouse Gas Initiative (RGGI). RGGI is a cap-and-trade program among nine states, including Rhode Island, aimed at reducing regional GHG (specifically CO_2) emissions from power plants with a generation capacity of 25 megawatts (MW) or more. RGGI is designed to achieve a regional power sector CO_2 emission reduction goal of more than 45 percent by 2020[2].

Additionally, the recently finalized federal Clean Power Plan (CPP), which aims to reduce national CO_2 emissions from the electric generation industry by approximately 32 percent from 2005 levels by 2030, has included as one of its key reduction measures the shift of electric generation (and resulting CO_2 emissions) from dispatch of existing solid and liquid fossil fuel-fired boilers to lower-emitting existing natural gas combined cycle combustion turbines.

The proposed Project would provide the supply of natural gas necessary for regional operators to take advantage of the compliance options and incentives for gas-firing that are built into the regional and federal environmental regulations discussed above. Such a shift to natural gas-firing would help achieve the emissions decreases required to meet air quality goals intended to protect public health that the regional and federal regulations seek to accomplish.

The USEPA has also recently released a final rule updating the New Source Performance Standards (NSPS) for the oil and gas industry designed to reduce CH_4 emissions from new and modified oil and gas sources, including pipeline compressor stations. The final rule, released May 12, 2016, will require new, reconstructed and modified gas pipeline projects to develop plans and actively monitor for CH_4 leaks and make repairs within 30 days of finding fugitive emissions. ANE will be designed and operated in compliance with all applicable requirements of this final NSPS rule, which will contribute to achieving EPA's goals of further overall reductions of CH_4 emissions from the oil and gas industry.

Lastly, the Rhode Island Division of Planning document entitled, *Energy 2035: Rhode Island State Energy Plan* indicates a goal of decreasing the reliance on liquid petroleum fuels in the thermal and transportation energy sectors in order to meet environmental and economic sustainability goals.[3] In order to meet this goal, the document foresees that an increase in renewable and natural gas fueled sources of thermal and transportation energy are required. While the primary purpose for the proposed Project is to alleviate winter-time gas supply constraints for electric generation facilities, a portion of the additional capacity could be available and distributed to other users depending on electricity generators' fuel demand. As such, the proposed Project would help achieve the prescribed shift in energy supply and thus support and advance the goal for increased environmental sustainability.

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[2] Relative to 2005 emissions.
[3] Rhode Island Division of Planning, *Energy 2035: Rhode Island State Energy Plan*, October 8, 2015, available at http://www.energy.ri.gov/energyplan/.

Projected Change in Air Pollutant Emissions

In an effort to quantify the potential impact that the proposed Project would have on regional air quality and CO_2 emissions, modeling was conducted in order to predict total regional NO_X, SO_2, and CO_2 emissions from power generation sources over the period of 2019-2038 for a Base Case that represents the "status quo" without any incremental natural gas infrastructure to serve gas-fired electricity generation and a case that includes the construction the ANE project. A discussion of that modeling and an assessment of the projected emissions changes can be found in Black & Veatch's companion report.[4]

The resulting emissions evaluation (including the projected changes in air emissions from the power industry) indicates that the construction of the proposed project will result in an overall regional decrease in emissions of NO_X, SO_2 and CO_2 relative to the Base Case. The results of the analysis can be seen in Table 1 below.

[4] See Black & Veatch's *Evaluation of Long-term Economic Benefits from Proposed Incremental Energy Infrastructure into New England*.

Table 1: Comparison of Projected Air Emissions from Power Generators and ANE - 2019-2038

TOTAL POLLUTANT EMISSIONS (TONS) 2019-2038			
Scenario	**NO_X**	**SO_2**	**CO_2**
Base Case	[redacted]		
With Access Northeast Pipeline			
Delta: Access Northeast – Base Case			

Impacts to Other (Non-Air) Regional Environmental Resources

Groundwater and Surface Waters

Project pipeline construction is not likely to result in significant groundwater impacts because the majority of construction would involve shallow, temporary, and localized excavation. If groundwater is encountered during pipeline construction, mitigation measures would be implemented to dewater the trench to well-vegetated upland areas or utilize an energy dissipation structure where dense vegetation is absent, allowing the water to infiltrate back into the ground and minimize any long-term impacts on the water table.

Shallow groundwater could be vulnerable to contamination caused by the inadvertent surface spills of petroleum and hazardous liquids used during construction. To reduce potential impacts from spills of petroleum and hazardous materials, a Spill Prevention Contingency and Countermeasures (SPCC) Plan will be prepared and implemented. Although the SPCC Plan generally addresses petroleum product storage, management, and spill prevention, the plan will be modified to incorporate management of hazardous materials as well. The contents of the SPCC Plan will comply with the provisions of 40 CFR Part 112, as well as regulations and guidance pertaining to hazardous materials established under authority of the Comprehensive Environmental Response, Compensation, and Liability Act, the Resource Conservation and Recovery Act, the CAA and the Clean Water Act.

In order to protect surface water resources, the Project will utilize sediment control measures during construction to avoid deposition of sand, silt, and /or sediment into sensitive environmental resource areas, including wetlands, waterbodies, and sensitive species habitats. ANE has committed to complying with the FERC *Upland Erosion Control, Revegetation, and Maintenance Plan, May 2013 ("Plan") and Wetland and Waterbody Construction and Mitigation Procedures, May 2013 ("Procedures").* Additionally, a Stormwater Pollution Prevention Plan (SWPPP) will be developed and implemented to satisfy Clean Water Act National Pollutant Discharge Elimination System requirements. A Horizontal Directional Drill ("HDD") Plan for monitoring and clean-up of drill mud returns

not captured or inadvertently released from a "frac-out" during the drilling will also be developed. The SWPPP and HDD plans will be submitted to FERC for approval prior to commencing construction.

Upon completion of construction, the ground surface will be restored in accordance with the FERC Plan and Procedures or approved Project-specific plans to facilitate restoration of disturbed areas.

Given the available measures identified and to be implemented during construction, ANE is not expected to have a material impact on regional groundwater and surface water resources.

Threatened and Endangered Species

During Project planning, publicly available reference data on threatened and endangered species ("protected species") having the potential to occur within the Project area was reviewed. This analysis identified likely locations for these species and their habitat to avoid to the maximum extent practicable during pipeline design. Field studies to determine the presence or absence of threatened and endangered species are set to be conducted in the spring and summer of 2016 for the "preferred" route.

Section 7 of the Endangered Species Act (ESA) requires federal agencies to ensure that any action authorized, funded, or carried out by the agency does not jeopardize the continued existence of federally listed endangered or threatened species, or result in the destruction or adverse modification of designated critical habitat for any federally listed species. To comply with the requirements of ESA Section 7, information and maps were provided to the USFWS, New York State Department of Environmental Conservation, Connecticut Department of Energy & Environmental Protection, Rhode Island Division of Planning and Development, and Massachusetts Energy and Environmental Affairs in November 2015 with a request to determine if the project would be located near any federally or state-listed endangered or threatened species (including species of special concern) or their designated critical habitats. Areas of concern identified through these agency consultations will be included in field studies to confirm the presence and extent of any protected species or their habitats. ANE will prepare a summary report describing the findings from the field studies for submittal to USFWS and the aforementioned state agencies for an ESA Section 7 determination. In the event protected species are found within or near the project footprint, a mitigation plan describing avoidance and minimization measures will be implemented.

Existing fish, wildlife, and vegetation resources that would be directly and indirectly affected by the project from construction and operation of the proposed facilities, along with the mitigation measures that are proposed to avoid or reduce these impacts will be described in draft Resource Report 3, Fish, Wildlife and Vegetation, which is scheduled to be filed with the FERC in June 2016.

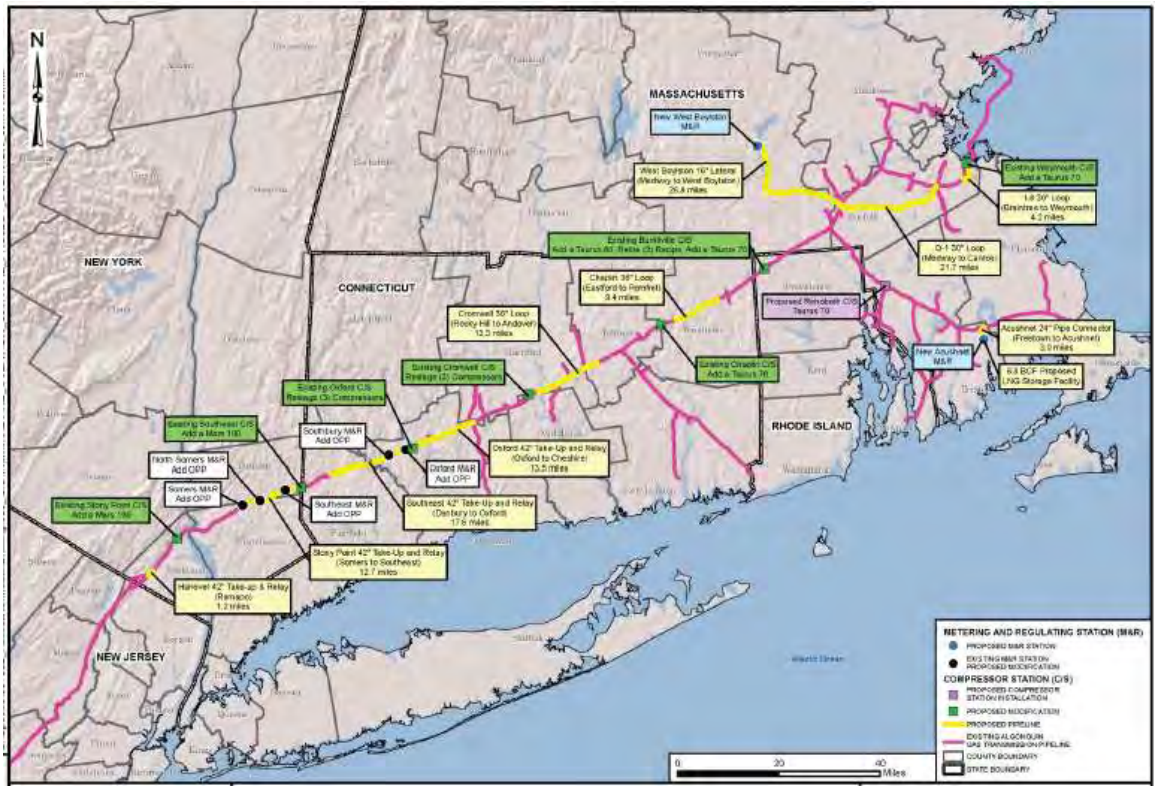
3.0 Direct Environmental Impact on Rhode Island

Access Northeast Pipeline

The Project will have limited direct environmental impact from its physical footprint in Rhode Island. As shown in Figure 1 below, the ANE project is proposing an upgrade of an existing compressor station located in Burrillville, Providence County, Rhode Island.

The compressor station upgrade will consist of the retirement of three existing reciprocating internal combustion engine (RICE) compressors and the installation of two new natural gas-fired Solar Taurus turbine compressor units. This will result in netting an additional 9,920 horsepower ("hp") [18,020 hp to be added and 8,100 hp to be retired retired]. The upgrades will also involve extension of one of the compressor buildings to house one of the new turbine compressor units, and demolition of part of one of the existing compressor buildings. The environmental impacts upon the air and noise quality, as well as other ecological and community resources associated with construction of the upgrades and subsequent operation of the compressor station and available mitigation techniques are discussed below.

Figure 1: Proposed Algonquin Access Northeast Pipeline



Air Emissions

The Burrillville Compressor Station is located in an area that is currently designated as in attainment of the NAAQS or unclassifiable for each criteria pollutant.[5] The new natural gas-fired combustion turbine compressor units will constitute a modification of an existing stationary source of air emissions and will therefore require a pre-construction air permit in order to authorize the construction of the new emissions sources. As such, the permit will require the project to be designed and operated in a manner consistent with the requirements of the EPA-approved Rhode Island State Implementation Plan (SIP), which is designed to maintain and/or improve the air quality of the state. Where necessary and appropriate the project will be designed with air emission controls required to achieve compliance with state and federal air regulations in order to support the maintenance of ambient air quality required by the Rhode Island SIP. Such controls could include low-NO_X burner technology, water/steam injection, and selective catalytic reduction (SCR) to control NO_X emissions and oxidation catalysts to control emissions of CO and VOC. Accordingly, the modified station will not significantly impact the ambient air quality.

Construction of the Burrillville Compressor Station upgrades will likely also produce temporary air emissions principally associated with construction activities such as the combustion of fuels in engines which propel or otherwise operate mobile or stationary construction equipment, and fugitive dust activities which entrain particles in the air through the disturbance and movement of soil and/or demolition of buildings. Where practicable, mitigation measures will be employed to minimize emissions associated with construction activities. Such measures include:

- Minimization of equipment idling;
- Proper tuning and maintenance of equipment;
- Speed restrictions on any unpaved roads and site access routes;
- Application of dust inhibitors such as surfactant sprays and/or water to suppress dust emissions;

Assuming the project is constructed and operated in a manner consistent with the preceding discussion, the construction and operation of the Burrillville Compressor Station is not expected to significantly impact ambient air quality.

Noise

Compressor stations supporting interstate natural gas pipelines are subject to FERC jurisdiction and are therefore required to meet FERC noise level requirements. Additionally, FERC requires that proposed projects identify any state and/or local noise level limits and generally requires that such requirements are met in addition to FERC limits. The proposed

[5] Burrillville, Rhode Island, is located in an area that was designated as non-attainment for the 1997 8-hour ozone standard. However, in the March 6, 2015, publication of the Federal Register, the 1997 ozone standard was revoked for all purposes. Therefore, preconstruction permitting is currently subject to the requirements of New Source Review (NSR) applicable to areas that are in attainment of the NAAQS or unclassifiable for each criteria pollutant.

upgrades at the Burrillville Compressor Station will be designed, constructed, and operated in a manner consistent with the requirements of FERC and state/local noise regulations.

As necessary to support regulatory requirements, construction noise mitigation will include consideration of the use of standard mufflers on equipment engines, an outreach program that keeps the public apprised of activities that could result in potential temporary increases to noise levels, and management of construction schedule to limit the occurrence of noisy activities during nighttime hours.

Noise analyses based on manufacturing data for the new replacement compressor units; layout of existing buildings and equipment; and operating conditions, will be conducted to evaluate the potential environmental noise impact (and mitigation thereof) at nearby noise sensitive areas ("NSAs") [i.e., residences], and documented in Resource Report 9 Air and Noise Quality to be filed with FERC. Project equipment designs will include consideration of noise mitigation measures such as acoustical silencers or enclosures as needed to conform to all applicable regulatory requirements. ANE plans to conduct noise surveys to verify that the noise attributable to operation of the two replacement compressor units will not exceed the Ldn [day-night sound level] of 55 dBA [decibels on the A-weighted scale] at any NSA in accordance with the FERC regulations [§ 380.12(k)(2)].

Nosie impacts and mitigations will be further outlined in Resource Report 9 Air and Noise Quality, which will be filed with FERC.

Wetlands and Waterways

Specific to Rhode Island, no wetlands or waterbodies will be impacted since Project activities are limited to upgrades of an existing compressor station on improved land. According to the U.S. Fish and Wildlife Service's Wetland Mapping Database, there are no wetlands of any kind on the proposed Burrillville Compressor Station project site. The nearest mapped wetlands are located approximately 168 meters west of the proposed site. Any associated temporary construction workspace outside of already improved areas of the existing station facility will be evaluated to determine if wetlands or waterbodies are present that may potentially be impacted. Any identified wetlands will be flagged and avoided wherever possible. Additionally, measures will be taken to control stormwater and accompanying sediment runoff from construction activities on the site from being discharged into any nearby wetlands.

Wetland and waterway impacts and mitigations for the Project will be discussed in Resource Report 2, Water Use and Quality which will be filed with FERC. The report will include special techniques that may be implemented to mitigate or avoid impacts during construction across water resources.

Threatened and Endangered Species

Specific to Rhode Island, no protected species are likely to be impacted since Project activities are limited to upgrades of an existing compressor station on previously disturbed, improved land. Any associated temporary construction workspace outside of already

improved areas of the existing station facility will be evaluated to determine the potential presence of protected species and their habitats.

Consultations with the USFWS and the Rhode Island Department of Environmental Management (RIDEM) will be conducted to determine if any federally or state-listed endangered or threatened species (including species of special concern) or their designated critical habitats are known to occur within the Project area. Field studies to determine the potential presence of threatened and endangered species are set to be conducted in the spring and summer of 2016.

If following these consultations and field studies no species or habitats are found to be present on the site, confirmation letters will be sought from the USFWS and RIDEM stating that no species or habitat will be impacted by the project, and the project will be allowed to continue. It is unlikely that any species will be identified on the compressor station site, as the site has been previously developed and is currently an operating compressor station.

Land Use and Community Resources

The proposed Burrillville Compressor Station upgrade will occur within the existing fenced compressor station footprint of approximately 6 acres, as shown on Figure 2. The fenced area, located within an approximately 270-acre undeveloped parcel owned by Algonquin, is approximately 3.4 kilometers ("km") from the west edge of the City of Burrillville limits. Construction activities specific to the Burrillville Compressor Station upgrades will occur within the existing fenced facility footprint.

Algonquin Lane, an existing road, will be used to access the Burrillville Compressor Station during construction and operation of the Project. Existing public roads will be used without modification or improvement, excluding routine maintenance. No new public roads are planned to be constructed.

Based on a review of the project area using Google Earth software, no residences are located within 500 meters of the proposed project site. Therefore, no impacts to existing residential areas are anticipated.

No public lands, national landmarks or scenic rivers are located within 0.25 miles of the Burrillville Compressor Station. Therefore, the proposed Project upgrades are not likely to result in a significant impact on any special land types or uses.

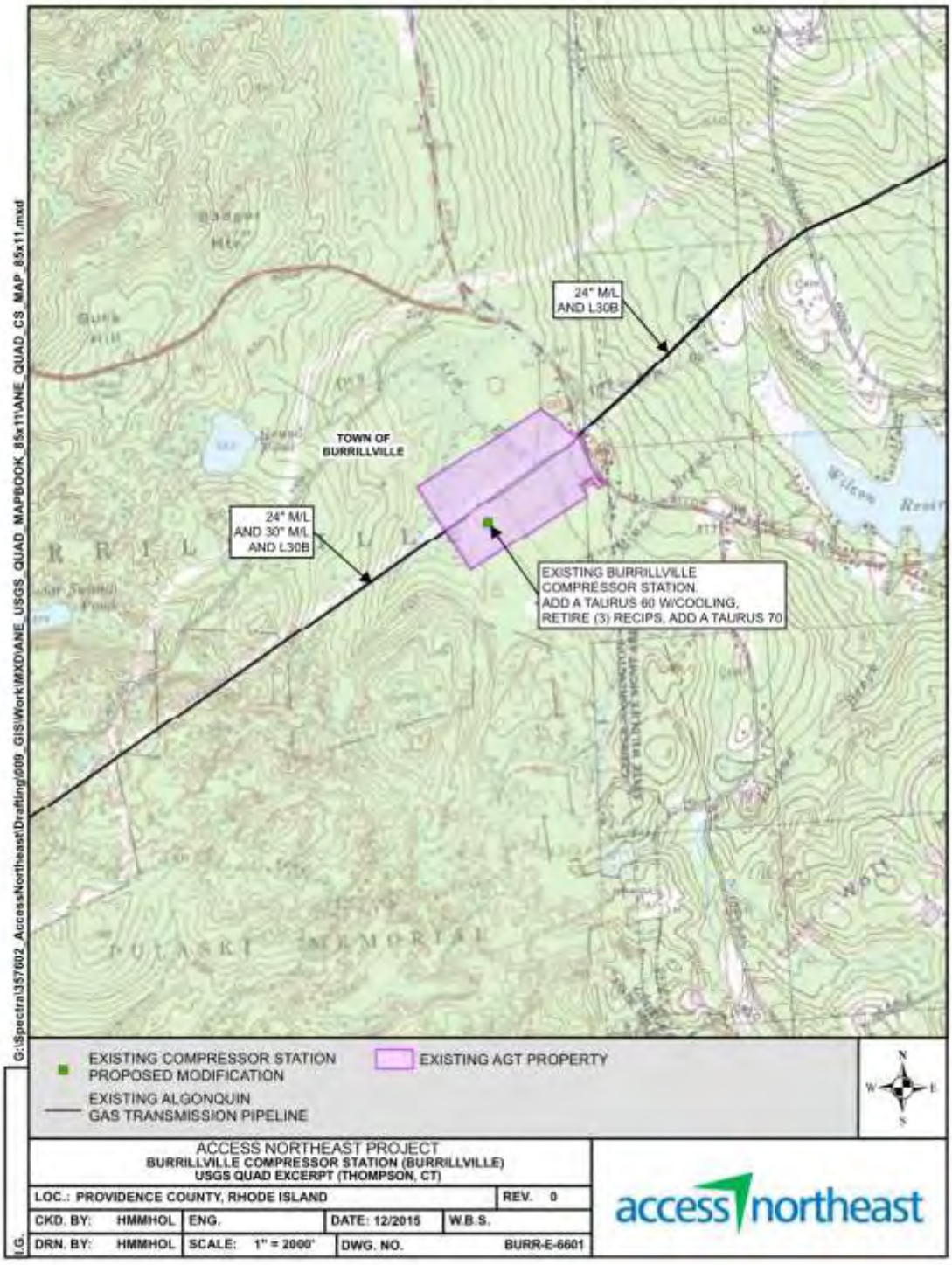
Cultural Resources

Rhode Island historic properties and cultural resources are protected by the Rhode Island State Historical Preservation Office (SHPO). Consultations with the Rhode Island SHPO as necessary to comply with Section 106 of the National Historic Preservation Act will be undertaken. Since the Burrillville Compressor Station upgrade activities will occur within the limits of previously disturbed land, it is anticipated that the Rhode Island SHPO will issue findings that the project will have "no effect" on historic properties. However, if recommended by the SHPO, a cultural resources survey will be conducted on the project site.

Cultural resources [including historic properties listed on or eligible for listing on the National Registry of Historic Places, or any traditional cultural properties within the project's Area of Potential Effect ("APE")] will be discussed in Resource Report 4, Cultural

Resources. The APE includes the area that may be directly or indirectly affected by construction, operation, and maintenance of proposed facilities, and associated activities for the Project.

Figure 2: Burrillville Compressor Station



Testimony of
Michael C. Calviou

DIRECT TESTIMONY

OF

MICHAEL C. CALVIOU

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I. Introduction and Qualifications

Q. Please state your name and business address.

A. My name is Michael C. Calviou. My business address is 40 Sylvan Road, Waltham, MA 02451.

Q. By whom are you employed and in what position?

A. I am Senior Vice President, U.S. Regulation and Pricing, for National Grid USA Service Company, Inc. (NGSC).

Q. What are your principal responsibilities in that position?

A. I am responsible for overseeing the regulatory and pricing function of National Grid USA (National Grid) across all of National Grid's United States (U.S.) jurisdictions and operating companies, including Narragansett Electric Company d/b/a National Grid (the Company).

Q. Please describe your educational background and professional experience.

A. I received a Bachelor's degree in Theoretical Physics from the University of Cambridge in 1990. I have spent 25 years working for National Grid plc in various capacities in the U.S. and United Kingdom (U.K.). During 2004-2005, I was Vice President, U.S. Transmission Regulation and Commercial. From 2006 to 2015, I served in multiple senior leadership positions in the U.K. responsible for Distribution Customer Support

(2006-2009), Asset Management (2009-2012), and Transmission Network Services (2012-2015).[1] As Director, Transmission Network Services, I led customer and commercial activities as well as the strategic design of the Great Britain (GB) electricity and gas transmission networks. This included managing the regulatory and contractual framework that governed connections to the electricity and gas transmission systems and responsibility for major policy decisions and development of strategy in relation to the market design and industry frameworks in the U.K. and Europe. From 2014-2015, I chaired the Executive Committee for National Grid plc's System Operator function (covering both electricity and natural gas) for GB. In these roles, I was heavily involved in the development of and National Grid plc's operation under Ofgem's RIIO regulatory framework (RIIO).[2] In addition to RIIO, I have had extensive experience in the development of other regulatory incentives in the U.K. and U.S. throughout my 25-year career. In September 2015, I returned to the U.S. on a permanent basis and assumed my current position as Senior Vice President, U.S. Regulation and Pricing.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC)?

A. No, I have not.

[1] In the U.K., a Director is equivalent to a Senior Vice President in National Grid's U.S. business.
[2] RIIO (Revenue=Incentives+Innovation+Outputs) is Ofgem's performance-based model for setting price controls for network companies. Ofgem is the U.K. national energy regulatory body.

Q. What is the purpose of your testimony?

A. My testimony discusses the role that utility innovation can serve to benefit the State of Rhode Island and its utility customers. I address the appropriateness of incentives as a regulatory tool to provide utilities with an inducement to devote resources to endeavors that may not be within their normal responsibilities but that have the potential to provide substantial benefits to customers. I propose principles consistent with the PUC's precedent related to utility incentives and designed to assure that incentives provide cost-effective inducement to utilities to deliver incremental benefits to customers in the future. I then apply these principles to the Company's pivotal role in developing a novel policy construct to solve a vexing regional energy challenge—namely, the acute winter natural gas shortage for electricity generation that has saddled the Company's customers with excessive energy commodity costs. The Company's decision to take on the substantial financial obligation of a long-term contract for natural gas pipeline capacity (Proposed Agreement) is part of an innovative strategy to improve reliability and lower electricity costs to Rhode Island electric customers. Finally, I present the Company's request for a financial incentive linked to the Proposed Agreement to compensate the Company for its innovative efforts, allow the Company to share in a small fraction of the net economic benefits its efforts will create for customers, and create an inducement for future innovative efforts by the Company that promise to yield additional customer benefits.

Q. Why is the Company proposing a financial incentive at this time?

A. The PUC currently provides incentives that encourage utility actions that advance policy goals and/or promote customer benefits. The Company views its extensive efforts to develop and implement a novel solution to one of New England's most critical energy challenges through the Proposed Agreement as the type of innovative activity that achieves both objectives. According to the economic modeling analysis conducted by Black & Veatch, the Proposed Agreement is projected to provide levelized net savings for the Company's customers of approximately $110 million per year over the life of the contracts.[3] Further, the Company will organize to pursue other innovative solutions if it receives confirmation that the PUC views this type of innovative utility effort to deliver substantial customer benefits as advancing the public interest and warranting of a financial incentive. Promoting innovation through utility incentives is an appropriate regulatory response to the evolving utility business environment and a logical and modest application of existing precedent and practice in similar contexts in Rhode Island and other New England jurisdictions.

Q. How is your testimony organized?

A. My testimony is organized as follows: following this introductory Section I, Section II describes the evolving electric utility business environment as driven by federal and state policies, market developments, and technology advances. Section III describes

[3] *See* Table 8 in Black & Veatch's *Evaluation of Long-term Economic Benefits from Proposed Incremental Energy Infrastructure into New England*, Schedule GJW-3.

the role that incentives can serve to efficiently achieve desirable energy outcomes including reducing and stabilizing high energy costs for Rhode Island consumers and ensuring system reliability.[4,5] This section also explains general principles that the PUC can use to evaluate when utility incentives are appropriate and how best to design them. Section IV applies these principles to the Company's proposal to enter into the Proposed Agreement and explains the importance of fully assured recovery of the Proposed Agreement's costs. Finally, Section V presents my conclusions and recommendations.

Q. How does your testimony relate to the testimonies of other Company witnesses?

A. My testimony focuses narrowly on the value of utility innovation and the role of incentives in promoting innovation. I focus on the Company's role in developing an innovative solution to a challenge faced by Rhode Island and New England with respect to shortages of natural gas in the winter for electric generation.

[4] Covering a June 2014 regional energy conference, the *Concord Monitor* reported: "'The lights did not go out this past winter,' said Rhode Island Office of Energy Resources' Nicholas Ucci at the forum hosted by the New England Council business association. 'That doesn't mean that they can't.' During this past winter, the region's energy market costs exceeded $5 billion, compared with $5.2 billion for all of 2012, Ucci said." Morris, Allie, "New England Energy Officials Warn of Possible Power Crisis; Governors Infrastructure Initiative Could Be the Solution," *Concord Monitor*, July 2, 2014, available at http://www.concordmonitor.com/home/12596728-95/new-england-energy-officials-warn-of-possible-power-crisis-governors-infrastructure-initiative-could.

[5] Similarly, in April 2015, "Massachusetts Secretary of Energy and Environmental Affairs Matt Beaton said … that unless New England addresses its natural gas pipeline constraints, the state will continue to see 'dramatic electricity price spikes' in the winter, and the risk of blackouts will increase." Schoenberg, Shira, "Seek to Expand State's Natural Gas Capacity, Baker administration Tells Department of Public Utilities," *The Republican*, April 14, 2015, available at http://www.masslive.com/politics/index.ssf/2015/04/baker_administration_directs_d.html.

II. Evolving Utility Business Environment

Q. How would you describe the current utility business environment?

A. The fundamental objectives of electric utility service have remained relatively constant over the past several decades: to provide safe, reliable, and affordable electricity service. Three additional objectives have gained prominence in recent years: environmental goals, system resiliency, and customer empowerment.[6,7,8] Environmental goals, especially those related to reducing the greenhouse gas

[6] Illustrating the focus on environmental goals and system resiliency, the 2015 Rhode Island State Energy Plan explains that "Rhode Island stands at a crossroads. Our existing energy system exposes the state to excessive risk, costs, and environmental damage." The plan presents three themes (i.e., security, cost-effectiveness, and sustainability), and the security theme includes the goals of reliability (i.e., "increase the system's ability to withstand disturbances") and resiliency (i.e., "increase the system's ability to rebound from disturbances"). *See* Rhode Island Department of Administration, Division of Planning, Energy 2035: Rhode Island State Energy Plan 1, 35 (October 2015).

[7] The Systems Integration Rhode Island Vision Document demonstrates the growing focus on customer empowerment. The document identifies several "foundations" that "describe attributes Rhode Island stakeholders seek in the state's energy/grid planning, procurement, and investment processes in order to enable the attainment of the stated goals." The first such foundation is to "Enable Customers: Customers will be viable sources of energy resources ('prosumers') through a proper balance of both utility regulation and markets." *See* Systems Integration Rhode Island Vision Document 8-9 (January 2016).

[8] The Company's affiliates (Massachusetts Electric Company/Nantucket Electric Company and Niagara Mohawk Power Corporation) operate in two of the jurisdictions (i.e., Massachusetts and New York, respectively) leading the way nationally in advancing policies to create what many in the industry term the "utility of the future." These additional fundamental objectives can be seen in the stated objectives of the Massachusetts Grid Modernization effort and those of the New York Reforming the Energy Vision ("NY REV") proceeding. Specifically, the four objectives of Massachusetts Grid Modernization are: (1) reducing the effects of outages; (2) optimizing demand, including reducing system and customer costs; (3) integrating distributed resources; and (4) improving workforce and asset management. *See*, Order in D.P.U. 12-76-B, June 12, 2014, at 10-13. The NY REV objectives are: (1) customer knowledge and tools that support effective management of their total energy bill; (2) market animation and leverage of ratepayer contributions; (3) system wide efficiency; (4) fuel and resource diversity; (5) system reliability and resiliency; and (6) reduction of carbon emissions. *See* Case 14-M-010, *Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues*, at 1-2 (August 22, 2014). The 2015 Rhode Island State Energy Plan stated that "[e]stablishing a working group to examine the results of the Massachusetts Grid Modernization Report and preparing a similar report taking into account the unique regulatory and rate structures in Rhode Island would help the state begin to chart a path forward on modernizing the electric grid and enhancing system reliability." See, Rhode Island Department of Administration, Division of Planning, Energy 2035: Rhode Island State Energy Plan 133 (October 2015).

emissions that cause global climate change, have led to an emphasis on energy efficiency and clean energy. The resiliency of the distribution system also has become an issue of greater focus for customers and regulators in today's increasingly "plugged-in," connected digital economy and society, particularly as a result of the impacts of severe weather events in recent years in Rhode Island and the rest of the U.S. Northeast. Customers and regulators have also become more interested in greater customer information, control, and options regarding their energy use.[9] As new energy technologies have emerged—ranging from clean energy generation to sophisticated distribution technologies to new consumer applications—the deployment and integration of new technologies has become a key pathway to achieve the aforementioned objectives. Moreover, efforts to rely on market forces over the past two decades—including the restructuring of the Rhode Island electricity market through legislation in 1996 and federal policy initiatives to rely on market forces to site natural gas and electric infrastructure and to create wholesale markets for energy products and services—have left electric distribution companies as the last remaining element of the electricity value chain that is still subject to comprehensive regulation by state regulators.

[9] *See*, e.g., D.P.U. 12-76-B at 1-2.

Q. What are the implications of this changing business environment on electric distribution utilities and regulators?

A. These trends are causing policymakers in several leading states, including Rhode Island,[10] Massachusetts,[11] California,[12] New York[13] and a few other states, to revisit traditional utility regulatory models, with, in some cases, a focus on outcome-based regulation that compensates utilities for delivering outcomes valued by customers. These states' efforts also include attempts to invigorate the electric utility industry with a heightened level of innovation. Moreover, electric distribution utilities are expected to continue to provide reliable service at an affordable cost even though a significant portion of a customer's energy bill is determined either "upstream" in wholesale electricity and natural gas markets or "downstream" through actions that customers can take on their side of the meter.

Q. How does this relate to the need for utility innovation?

A. In the context of the utility industry, innovation includes the invention, development, and deployment of not only new technologies or products but also new business

[10] *See, e.g.*, Systems Integration Rhode Island Vision Document (January 2016), the Staff Memorandum to the Commission RE: Recommendations for a Docket to Investigate the Changing Distribution System (March 1, 2016), and the subsequent Commission decision to open Docket No. 4600.

[11] *See, e.g.*, D.P.U. 12-76-B.

[12] *See, e.g.*, Stanfield, Jeff, *California Blazes Trails to Map Wild Frontier of Distributed Energy Resources*, SNL Financial (November 30, 2015).

[13] New York Public Service Commission, Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*.

processes, services for customers, and energy and regulatory policies and frameworks. Clearly, much of the innovation that leads to the development of new energy technologies is driven by the unregulated, competitive sector of the economy and financed by investors. However, utilities must be innovative in adopting and integrating new technologies, developing new business and planning processes to exploit new technologies and to drive operational efficiencies, offering new options for customers, and working with policymakers, regulators, and other stakeholders to create an energy policy and utility regulatory framework that meets the aforementioned key objectives of utility service and addresses current and emerging energy challenges. The growing importance of emerging energy technologies, the ambition of Rhode Island's clean energy and environmental policy goals, and the need for creative thinking to achieve energy goals that require action outside the traditional purview of state regulators all require additional innovation in the utility industry. The Proposed Agreement accompanying the Company's petition in this docket highlights, in particular, how utility innovation can improve affordability for customers. Innovation can impact affordability in numerous ways beyond the present case, ranging from "smart grid" investments that reduce the economic impact of outages on customers to new policy approaches to meet clean energy goals more cost-effectively. In general, as policymakers and customers demand more from utilities, innovation will be essential for utilities to meet those

demands affordably.[14,15] It is particularly fitting that Rhode Island should foster innovation in the utility industry given Governor Raimondo's present focus on fostering innovation-based economic development in Rhode Island.[16] A PUC policy to provide incentives for utility innovation that delivers customer benefits can spur future efforts by the Company to develop innovative solutions. A regulatory environment supportive of innovation is necessary for customers to benefit from new technologies, creative policies, and other fruits of innovation as the evolution of the industry brings new challenges.[17] Setting the stage for innovation is crucial because, as the Massachusetts Department of Public Utilities (MADPU) has explained, "[w]e cannot know today all the advances and technological breakthroughs that will occur in the electricity sector over the next decades."[18]

[14] *See e.g.*, Massachusetts Institute of Technology, The Future of the Electric Grid 24-25 (2011) (report finding that"the tendency of traditional regulatory systems to encourage excessively conservative behavior is likely to become more and more expensive over time if increasingly attractive opportunities to enhance efficiency and reduce cost through innovation are not exploited.").

[15] In adopting RIIO, the U.K. energy regulator, Ofgem, explained in its chapter on "Encouraging Innovation" that "[Distribution Network Operators (DNOs)] face significant challenges over the coming years, such as facilitating the transition to the low carbon economy. To meet these challenges cost efficiently, DNOs will need to try new operational, technical, commercial and contractual arrangements within their business." Ofgem, *Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control: Outputs, Incentives and Innovation, Supplementary Annex to RIIO-ED1 Overview Paper*, Mar. 4, 2013, at 96.

[16] Press Release, Office of the Governor, Raimondo Works to Spark Innovation Economy (November 18, 2015).

[17] For example, former FERC Commissioner and current Chief Customer Solutions Officer at the Edison Electric Institute ("EEI"), Philip D. Moeller, explained that: "While new technologies and customer expectations are playing critical roles in the industry's ongoing transformation, the speed of transformation will depend, to a great extent, on whether regulation evolves to accommodate these changes. The grid is more complex, and customers have different expectations, meaning that the regulatory model also must change. Over the next decade, regulation will have to provide a way for utilities to achieve new corporate and policy goals that meet the needs of their customers. That means meeting the traditional goals of providing safe, reliable, and affordable electricity, as well as the new goals of providing even cleaner electricity and individualized customer services, while also integrating and connecting more distributed energy resources and devices." The Edison Electric Institute's 2016 Wall Street Briefing, February 10, 2016, at 12, available at http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/Documents/Wall_Street_Briefing.pdf.

[18] D.P.U. 12-76-B at 1 (June 12, 2014).

III. Incentives as a Regulatory Tool

Q. What role can utility incentives serve in fostering innovation?

A. Simply stated, incentives spur innovation.[19] They are particularly important when financial and human capital are required to pursue ventures that utilities are not obligated to pursue and/or are not guaranteed to be successful. Regulators also use incentives to promote the achievement of important policy goals.[20] Incentives are applied to activities that are typically limited to utilities but are also used to promote important outcomes that could be provided by a competitive market but remain underserved (e.g., energy efficiency for certain market segments). Both regulators and utilities are in a position to take a longer-term view as necessary to promote the public interest.

Q. What role do incentives play in promoting utility innovation?

A. Incentives provide a clear signal and economic rationale to utilities to pursue innovation on behalf of customers. Incentives are an appropriate regulatory response to existing barriers to utility innovation attributable to the cost-of-service ratemaking model.[21] Providing a modest but meaningful financial incentive for innovation helps

[19] For example, the MADPU has found that "[i]ncentive regulation recognizes the legitimacy of profit as an important motivator for utilities." D.P.U. 94-158 at 46.

[20] For example, a July 2013 report from the Institute for Electric Innovation found that 28 U.S. electric utilities have performance incentives described as "mechanisms that reward utilities for reaching certain electric efficiency program goals." Institute for Electric Innovation, State Electric Efficiency Regulatory Frameworks 2 (2013).

[21] *See, e.g.*, Malkin, David and Paul A. Centolella, Results-Based Regulation, Public Utilities Fortnightly 29-36 (2014).

utility rate regulation better mirror the outcomes of a competitive market where firms earn higher returns from innovating and providing products and services that deliver more value for customers. The dynamic effect of incentives is noteworthy. A consistent policy of providing incentives to utilities for innovation that yields customer benefits will spur utilities to seek out previously unanticipated and novel opportunities for innovation such as the Company's present proposal. In fact, PUC precedent supports the use of incentives to encourage innovation, align the interests of customers and utilities, and direct the attention of utilities toward specific policy goals.[22,23,24]

Q. What are some examples of incentive mechanisms that have been used in Rhode Island?

A. The Company has a Gas Procurement Incentive Plan (GPIP) to encourage the Company to reduce the risk that commodity costs will escalate dramatically. The Plan is designed such that the Company locks in the price of a portion of the forecasted gas purchases beginning two years prior to the month of delivery and continuing up until the month of delivery to help stabilize gas costs. The timing of a portion of these

[22] For example, concerning demand-side management (DSM) programs, the Commission explained that "the Commission believes that a greater incentive may provide Narragansett with the additional incentive needed to innovate and grow those [DSM] programs." PUC Order No. 17106(Docket No. 3240) (August 20, 2002).

[23] "The Commission approves the continuation of the [energy efficiency program] shareholder incentive mechanism as a means of aligning the interests of the utility with assisting its customers to use energy more efficiently." PUC Order No. 19608(Docket No. 4000) (April 6, 2009).

[24] "[T]he supplement of the performance based metrics [for calculating the energy efficiency program shareholder incentive] will give the Commission the opportunity to direct Narragansett toward specific policy goals for the year ahead." PUC Order No. 17516(Docket No. 3463) (July 21, 2003).

fixed-price purchases is at the discretion of the Company. The GPIP incentive encourages the Company to look for opportunities to lock-in a fixed price on the discretionary purchases such that the average hedged costs are lower with the discretionary purchases than without. The Company's incentive varies depending on the unit cost savings of the discretionary purchases and the timing.

The Company also has a Natural Gas Portfolio Management Plan (NGPMP) incentive. The NGPMP is an incentive which encourages the Company to maximize the savings to customers through optimization of the Company's pipeline transportation, storage and supply assets. The Company looks for opportunities to release capacity and make bundled sales using the portfolio of gas supply assets when the gas supply assets are not needed to meet the firm sales customer requirements. The Company receives a percentage of the savings when the total annual savings exceed $2 million. The percentage share the Company receives starts at 20% for savings in excess of $2 million, steps down to 10% for savings in excess of $5 million, and ratchets down again to 6% for savings in excess of $10 million.

Q. Has the PUC supported incentives for achieving certain societal benefits, such as those associated with increased energy efficiency and the purchase of renewable power?

A. Yes, with respect to energy efficiency, the PUC has approved shareholder

incentives for the Company's energy efficiency programs dating back to 1990.[25] Currently, the Company's energy efficiency programs are subject to a shareholder incentive mechanism of 1.25 percent of the annual spending budget for achieving 75 percent of the savings goals in a sector, increasing linearly to 5 percent of the annual spending budget for achieving 100 percent and then from that point to 6.25 percent of the annual spending budget for achieving 125 percent of the savings goals.[26] Regarding the energy efficiency incentive, the PUC has explained that it "approves the continuation of the shareholder incentive mechanism as a means of aligning the interests of the utility with assisting its customers to use energy more efficiently."[27] Similarly to the Company's Proposed Agreement, energy efficiency programs entail utility efforts to achieve, among other benefits for customers, energy commodity cost savings.

In addition, the PUC has approved Company tariffs allowing for the collection of performance incentives associated with the procurement of long-term renewable electricity. Such incentives are associated with the procurement of long-term renewable electricity for retail customers from wholesale power providers, and

[25] The shareholder incentive mechanism was first agreed to pursuant to a Stipulation of the Division of Public Utilities and Carriers, Attorney General James E. O'Neil, the Conservation Law Foundation of New England, Inc., and The Narragansett Electric Company entered into in connection with the Company's 1990 Conservation and Load Management (C&LM) program, which the PUC approved in Order No. 13281 (Docket No. 1939).

[26] Energy Efficiency Program Plan for 2016 Settlement of the Parties, Docket No. 4580, October 15, 2015, at 26. The PUC approved the 2016 Plan at an Open Meeting on December 16, 2015.

[27] PUC Order No. 19608 (Docket No. 4000) (April 6, 2009).

separately from eligible distributed-generation projects, the latter under the Renewable Energy Growth Program.

Q. Did the Company's affiliates in Massachusetts request the same financial incentive linked to their proposed long-term contracts for incremental gas infrastructure?

A. Yes. In D.P.U. 16-05, Massachusetts Electric Company and Nantucket Electric Company submitted to MA DPU a request for the same financial incentive requested by the Company in this case.

Q. Do MADPU policy and precedent similarly support the financial incentive requested by the Company's affiliates in Massachusetts?

A. Yes. Specifically, the MADPU's generic policy order on incentive-based ratemaking states, "the Department has concluded that the expanded use of well-designed incentive regulation mechanisms can be more responsive to customers' needs and the changes in the marketplace, while also meeting its other statutory obligations."[28] This generic proceeding was initiated to establish a foundation for performance-based ratemaking but also addressed other types of approved incentives (i.e., related to

[28] D.P.U. 94-158 at 46.

demand side management, electric generating unit performance, and gas margin sharing) and the role of utility incentives broadly.[29]

Q. What are some examples of incentive mechanisms that have been used in Massachusetts?

A. One recent example is the incentive approved in Massachusetts Electric Company's and Nantucket Electric Company's smart grid pilot proposal (the Smart Energy Solutions program in Worcester, Massachusetts) to be earned for participation by a larger number of customers and demonstration of higher bill savings than the levels identified in statute.[30] The MADPU also reserves the authority to establish a utility's authorized return on equity (ROE) as a type of incentive. This is illustrated by the MADPU's order in Massachusetts Electric Company's and Nantucket Electric Company's most recently completed electric rate case before the MADPU: "going forward, the Department will look to the role that utilities play in achieving the energy policy goals of the Commonwealth when setting a company's required ROE."[31] The MADPU has extensive experience with utility incentives for energy efficiency programs. It is noteworthy that the MADPU specifically affirmed "that performance incentives have historically worked well in encouraging successful, effective energy

[29] D.P.U. 94-158 at 39.

[30] D.P.U. 11-129 at 82-83, 86.

[31] D.P.U. 09-39 at 400.

efficiency programs."[32] The MADPU also has a long history of providing financial incentives to gas distribution companies in the form of capacity management margin sharing, regarding which the MADPU has noted that "when utilities are given a financial stake in improved efficiency and a greater share of the resulting cost savings, real benefits to customer can be achieved" D.P.U. 93-141-A at 59[33] and that the margin sharing arrangement provides gas distribution companies with "incentives and flexibility to aggressively pursue innovative strategies."[34] Lastly, another example is the remuneration to the Massachusetts electric distribution companies entering into long-term contracts for renewable energy, which is provided to compensate a company for accepting the financial obligation of the long-term renewable energy contract.[35]

Q. Has the MADPU previously adopted principles to determine when incentives are appropriate?

A. Yes. In its Order on incentive-based regulation, the MADPU examined and affirmed its authority to implement and approve incentive-based regulation.[36] This Order explicitly provides direction on and invites the submission of utility incentives beyond

[32] D.P.U. 08-50-A at 47.

[33] D.P.U. 93-141-A at 59.

[34] D.P.U. 10-62-A at 34.

[35] D.P.U. 13-147 at 63.

[36] D.P.U. 94-158 at 39.

those specifically contemplated in that Order.[37] The Order listed ten criteria, adding that, "in providing this enumeration, the Department does not intend to deter petitioners from proposing other appropriate criteria or methods to achieve the Department's goals."[38]

More recently, the MADPU issued an order that established principles regarding incentives in the Commonwealth's energy efficiency programs.[39] That order broadly addresses the requirement for energy efficiency program administrators to develop and deploy "significantly expanded and more innovative energy efficiency programs."[40]

Q. What is an appropriate list of principles for the current context?

A. Drawing on PUC precedent, industry best practice in fostering innovation,[41] and the experience of the Company and its affiliates with regulatory incentives, the Company proposes the following set of principles for a utility incentive for innovative activity:

1) In order to qualify for an incentive the innovation efforts should:

[37] D.P.U. 94-158 at 43.

[38] D.P.U. 94-158 at 55.

[39] D.P.U. 08-50-A at 49-50.

[40] D.P.U. 08-50-A at 1.

[41] *See, e.g.*, Caldwell, S., Yardley Jr., R., & Coyne J., Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers (Discussion Paper Prepared for the Canadian Electricity Association and the Canadian Gas Association, August 2014) (available at http://www.electricity.ca/resources/publications/stimulating-innovation.php.

a. Focus on activities that leverage a unique strategic role that can be served by the utility or in circumstances where there is a demonstrated market failure;

b. Produce significant benefits to customers and/or promote Rhode Island's energy policy goals; and

c. Apply to activities where the distribution company plays a distinct and clear role in bringing about the desired outcome.

2) With respect to the incentive:

a. The size of the incentive should be large enough to motivate utility attention, but be relatively small compared to the potential customer and public benefits;

b. The incentive and any other ratemaking elements should fairly balance risk and return between customers and shareholders; and

c. The incentive should be easy to administer.

Establishing and communicating a set of principles preserves the regulatory guidance and oversight roles, while providing the motivation and flexibility that utilities require in order to pursue innovation where it makes the most sense.

IV. The Company's Proposed Natural Gas Pipeline Contract Incentive

Q. Why is the Company proposing an incentive related to its efforts to solve the acute natural gas transportation shortage that faces Rhode Island and the rest of New England?

A. The Company has devoted considerable effort and resources to develop an innovative solution to a regional problem that was arguably beyond either its responsibility or

influence. It engaged in a sustained, multi-year effort without assurance that a viable solution would be reached. Moreover, while the Company's efforts furthered an outcome supported by Governor Raimondo, the Company risked conflict with key industry stakeholders opposed, for various reasons, to new natural gas pipelines.[42] The Company believes that these types of efforts are worthwhile and that the public interest will be served if utilities have an incentive to continue to pursue innovative solutions that benefit their customers and the State of Rhode Island.

Q. Why did the Company decide to pursue a solution to high natural gas prices?

A. The Company has been committed to finding a viable solution to the problem of high natural gas prices since it became apparent that there was a suboptimal amount of natural gas pipeline capacity serving New England.[43] This shortfall revealed itself in constraints in firm transportation capacity available in the region sufficient to both

[42] For example, in August 2015, Governor Raimondo said "she, like [Massachusetts Governor] Baker, supports increasing natural gas capacity to the region." Murphy, Matt, *Governor Gina Raimondo: Forget Mass., R.I.'s Real Competition Is Southern States*, The Herald News, August 7, 2015, available at http://www.heraldnews.com/article/20150807/NEWS/150807558.

[43] The Company's affiliates described in more detail how ISO-NE has explained this fundamental imbalance between gas-fired generators' need for gas transportation capacity and the capacity available to them as well as the impact the resulting shortage of gas transportation capacity has had in terms of winter price spikes and reliability concerns. *See* Initial Comments of Massachusetts Electric Company and Nantucket Electric Company in D.P.U. 15-37, *Investigation by the Department of Public Utilities upon its own Motion into New Natural Gas Delivery Capacity, Including Actions to be Taken by the Electric Distribution Companies*, at 2-10 (June 15, 2015). For example, the ISO-NE Internal Market Monitor's 2013 Annual Report noted that: "[W]holesale electricity costs… in 2013 compared with 2012 … increased by about 45%, while energy costs increased by about 57%. [The] increase in energy costs was the result of an increase in natural gas prices.… In fact, the increase in natural gas consumption by New England generators since 1999 accounts for more than 95% of the overall increase in natural gas consumption for the region. The confluence of these forces has resulted in a much higher proportion of electricity being generated by gas-fired generators in New England, while pushing gas pipeline capacity to its limits during periods of peak gas demand." ISO-NE Internal Market Monitor's 2013 Annual Report 2-3 (May 6, 2014).

satisfy the gas local distribution companies' need to supply their firm load customers and to also satisfy the needs of the electric generators that rely solely or partially on natural gas to generate electricity.[44] These constraints led to high and volatile natural gas prices[45] that translated directly into large increases in electricity prices for all of our customers, including the large proportion of residential and small commercial customers that rely on standard offer service because natural gas-fueled generation sets electricity market prices for a high proportion of the year. In effect, the Company was responding to the same concerns as regional policymakers. The Company recognized that the region's utilities could, with the approval of their regulators, play a uniquely effective role in addressing the natural gas capacity constraint and yield billions of dollars in savings for Rhode Island and New England electricity customers.[46]

Q. Is the Company obligated to pursue a solution to high winter electricity prices and reliability concerns?

[44] D.P.U. 15-37 at 12.

[45] *Id*.

[46] Corroborating the Company's view of the unique role of utilities in providing benefits to Rhode Island and the rest of New England, SNL Financial reported that, at the 2016 National Association of Regulatory Utility Commissioners' winter meeting in Washington, D.C., ISO-NE President and Chief Executive Officer Gordon van Welie "said that the markets will not incent incremental investments in infrastructure that is shared, such as big new transmission lines and pipelines. Such things 'are in essence a public good' and will require some sort of cost of service investment." Boshart, Glen, *Centralized Power Markets' Ability to Accommodate States' Desires Fiercely Debated*, SNL Financial, February 17, 2016.

A. No. There is no statutory or regulatory obligation for the Company or the other electric distribution utilities in New England to solve this problem. However, high wholesale electricity prices due to natural gas infrastructure constraints make electric supply less affordable. Our customers do not necessarily understand how and why electricity prices are high, the distinct contribution of wholesale markets and distribution service to their total electricity bill, or the impediments to electric generators executing long-term contracts necessary to finance new pipeline capacity. Nonetheless, our customers should reasonably expect the Company (and policymakers) to do everything in their power to address the excessive winter electricity prices caused by inadequate natural gas pipeline capacity. The fact that natural gas and electricity prices have been much lower in other parts of the country can put the Company's business customers that compete in national markets at a disadvantage, potentially harming the Rhode Island and New England economies.[47]

[47] Covering Governor Raimondo's remarks at an August 2015 luncheon hosted by the New England Council, The Herald News reported: "'Forget about competing against each other, Massachusetts and Rhode Island. We as a region need to compete with the Carolinas - North Carolina, South Carolina - Florida, Texas, Louisiana,' [Governor Raimondo] said in reference to energy prices putting pressure on businesses." Murphy, Matt, *Governor Gina Raimondo: Forget Mass., R.I.'s Real Competition Is Southern States*, The Herald News, August 7, 2015, available at http://www.heraldnews.com/article/20150807/NEWS/150807558.

Q. When did the issue of high natural gas prices begin to draw the attention of Rhode Island and other New England policymakers?

A. The impact that pipeline capacity constraints had on regional electric prices became very noticeable after the winter of 2011/2012.[48] Due to the nature of standard offer service procurement in Rhode Island and similar procurement in other New England states, customer bill impacts lagged the wholesale energy market price spikes. Policymakers began to study the phenomenon by assessing whether natural gas pipeline capacity constraints or other market forces were contributing to the issue. In December 2013, the New England Governors issued a collective statement (New England Governors' Statement) that acknowledged the contribution that both energy efficiency and new energy infrastructure, including natural gas pipelines and renewable generation, could make to the region's shared energy, environmental, and economic objectives.[49] The New England States Committee on Electricity (NESCOE) became actively engaged in studying the challenge, building upon initial 2012 and

[48] In a June 2012 study commissioned by ISO New England, ICF International described how "there is a growing concern about the adequacy of the regional natural gas infrastructure to serve electric generation demand under the traditional approach taken by most generators, whereby they choose to rely on interruptible pipeline transportation services" and concluded that "[i]n each of the scenarios and cases examining gas supply and demand under winter design day conditions, there is not enough gas supply capability remaining to meet the anticipated power sector gas demand after LDC firm demands are fully met." ICF International, Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs 1, 4(June 2012).

[49] "New England Governors' Commitment to Regional Cooperation on Energy Infrastructure Issues (December 2013), available at http://nescoe.com/resources/govs-stmt-infra-dec2013/. The New England Governors' Statement explained that "[t]o ensure a reliable, affordable and diverse energy system, we need investments in additional energy efficiency, renewable generation, natural gas pipelines, and electric transmission."

2013 regional gas-electric studies performed by Black & Veatch.[50,51] Several studies reached the same conclusion: New England needs more natural gas supply infrastructure. The question became how to accomplish this outcome given regulatory, market, siting, and other challenges. The Company, working with NESCOE, elected officials, and other electric distribution companies, became a leader in an intense effort to arrive at the current solution.

Q. Has the PUC reached a conclusion with respect to the shortage of pipeline capacity?

A. Yes. The PUC recognized the impact of natural gas pipeline capacity in a recent decision:

> Half of the electricity generated in New England is from gas-fired plants, and with ninety-five percent (95%) of proposed new generation coming from gas and wind resources, the trend is toward more, not less, natural gas. During periods of peak demand, i.e. the coldest days of winter, New England suffers from the inability to import needed natural gas from neighboring states like Pennsylvania, which are plentiful in natural gas. This constraint has led to

[50] Black & Veatch, Natural Gas Infrastructure and Electric Generation: A Review of Issues Facing New England (Prepared for The New England States Committee on Electricity, December 14, 2012).

[51] Black & Veatch, *New England Natural Gas Infrastructure and Electric Generation: Constraints and Solutions*, Prepared for The New England States Committee on Electricity, April 16, 2013.

increasingly high wholesale electricity prices.[52,53]

Q. Have other key New England energy industry stakeholders reached a similar conclusion with respect to the shortage of pipeline capacity?

A. Yes. At the request of the Massachusetts Department of Energy Resources (MA DOER), the MADPU opened an investigation on April 27, 2015, (D.P.U. 15-37) to examine the MADPU's authority to approve long-term natural gas pipeline contracts entered into by the Commonwealth's electric distribution companies. Although the MADPU's October 15, 2015, D.P.U. 15-37 Order focused on its authority to approve the contracts and related legal issues, it described the issue in some detail based on evidence that had been submitted by the MA DOER and other parties, and reached the following conclusion:

> On balance, the Department finds that DOER and other parties to this proceeding have provided sufficient information to support DOER's assessment of current New England wholesale market conditions and to arrive at the conclusion that increasing regional gas capacity will lead to lower

[52]The Narragansett Electric Company d/b/a National Grid's Proposed Standard Offer Service Rates for Residential and Commercial Groups (January through June 2015) and Industrial Group (January through March 2015), PUC Report and Order No. 21827, at 11-12 (Docket No. 4393) (February 23, 2015)., .

[53] The PUC's conclusion was echoed by Rhode Island's U.S. Senator Sheldon Whitehouse who, in January 2016, said "Rhode Island and a large part of Southern New England are on the wrong side of a couple of gas pipeline choke points, with the result that at certain times costs soar in Rhode Island because the choke point creates a supply-demand imbalance which causes prices to soar." Nesi, Ted, *Senator Whitehouse Backs Burrillville Power Plant*, WPRI, January 23, 2016, available at http://wpri.com/2016/01/22/sen-whitehouse-backs-burrillville-power-plant/.

wholesale gas and electricity prices.[54]

Similarly, in the "State of the Grid: 2016" presentation, Gordon van Welie, President and Chief Executive Officer of ISO New England ("ISO-NE"), explained that:

> The New England power system continues to be in a precarious position during extended periods of extreme cold. The region will continue to be in this position until the New England's [sic] natural gas infrastructure is expanded to meet the demand for gas. New England needs additional energy infrastructure. That includes natural gas infrastructure to meet growing demand for natural gas for both heating and power generation. [T]he price of wholesale power in New England is directly correlated to the price of natural gas. When generators can't get natural gas, prices spike.
>
> Booming production of natural gas from the Marcellus Shale, on New England's doorstep, has made low-priced natural gas available to the region, most of the time. When there's enough pipeline capacity to serve the region's power generators, New England's wholesale electricity prices can compete with the prices in regions where electricity is typically less costly. In winter, though, the pipelines serving New England are operating at full capacity just to meet heating demand. When that happens, we've experienced challenges to power system reliability as well as extreme price spikes.[55]

Q. Please describe the Company's efforts in more detail.

[54] D.P.U. 15-37 at 12.

[55] ISO-NE, *State of the Grid: 2016 – Remarks*, January 26, 2016, available at http://www.iso-ne.com/static-assets/documents/2016/01/20160126_remarks_2016stateofthegrid.pdf.

A. The Company worked closely with its peer utilities, NESCOE, state policymakers, and other stakeholders to explore multiple solutions to the regional gas capacity shortage. It became clear to the Company that the competitive wholesale energy markets would not solve this problem, and that no other entities were as uniquely positioned to address the regional challenge as the electric distribution companies. In collaboration with its peer utilities, the Company proposed a novel, "first-of-its-kind" construct under which electric distribution utilities would contract for incremental natural gas capacity to serve electricity generators on behalf of the utilities' customers. As New England's political leaders have grappled with the gas capacity shortage that has threatened electric reliability and increased their constituents' energy costs, the Company has been providing constructive input into the regional deliberations and moving the utility contracting model ahead through education and outreach efforts with state and federal officials (including the Federal Energy Regulatory Commission, FERC), stakeholder processes (e.g., NEPOOL), and a commitment to advance a workable approach to address the gas capacity shortage problem to deliver benefits to customers in a timely manner.[56]

[56] *See, e.g.*, Letter to NESCOE from Northeast Utilities, National Grid, and UIL Holdings, Re: Gas Capacity Infrastructure Expansion in New England (April 22, 2014) (on file with authors).

Q. Please describe the Company's proposed incentive for innovation related to the Proposed Agreement.

A. The Company is requesting an incentive equal to 2.75 percent of annual fixed contract payments under the Proposed Agreement. Company Witness Leary provides the proposed tariff language that defines the incentive calculation and explains how the incentive payments would be recovered from customers along with the costs of the Proposed Agreement. This is a modest amount relative to the projected benefits from the Proposed Agreement. Based on the projections from Black & Veatch, the proposed incentive would be equivalent to roughly 0.8 percent of the levelized net economic benefits to the Company's customers from the Proposed Agreement.[57] This level of incentive is the same percentage applied to long-term contracts for renewable energy under R.I. Gen. Laws §39-26.1-4 and is substantially less than the percentage of energy efficiency program expenditures available as a shareholder incentive. Moreover, this incentive is material enough to cause the Company to continue to look for innovative solutions that create benefits for customers, address Rhode Island's energy policy priorities, and advance the key objectives of utility service in the evolving utility business environment.

[57] Table 8 in the Black & Veatch report in this docket provides the projected levelized annual costs and net benefits for the Company's customers. 2.75 percent of $0.032 billion in levelized costs divided by $0.109 billion in levelized net benefits yields 0.8 percent of levelized net benefits.

Q. Is the proposed solution consistent with the principles for an incentive?

A. Yes. Most importantly, the Proposed Agreement addresses a failure of the competitive wholesale market to provide affordable and reliable supply. The Proposed Agreement provides direct economic benefits to customers that vastly exceed the proposed incentive, even before considering the reliability benefits from the Proposed Agreement. Lowering electricity costs provides other public benefits by supporting economic development and making electricity more affordable for low and moderate-income customers in Rhode Island and the rest of New England. The Company's efforts to address the regional gas capacity shortage make use of the utilities' unique position in the market relative to their regulators and customers. Finally, the proposed incentive fairly balances risk and return between customers and shareholders and will be easy to administer. No other New England stakeholder has put forth a realistic alternative proposal that can provide the level of customer benefit that the Proposed Agreement will yield. The Company believes that a 99.2 percent allocation of net benefits to customers, with the remaining small fraction allocated to the Company, is appropriate given the Company's proactive efforts to develop a novel construct and then see it through implementation in order to solve a competitive market failure, especially in this case where the solution brings such substantial direct economic benefits for customers.

Q. Is the approval of the requested incentive within the PUC's authority?

A. Yes. The Affordable Clean Energy Security Act (the ACES Act) specifically authorizes the PUC, in the context of reviewing long-term gas pipeline contracts proposed by electric distribution companies, to "[a]pprove any other proposed regulatory or ratemaking changes that reasonably advance the goals set forth herein."[58] As the Company's application in this proceeding demonstrates, the Proposed Agreement meets the ACES Act's stated purpose by providing net economic benefits to Rhode Island, enhancing electric system reliability, and delivering environmental net benefits.[59]

Q. Please describe the Company's request for recovery of the costs of the Proposed Agreement and the importance of fully assured cost recovery over the duration of the Proposed Agreement.

A. Company Witness Leary presents the Company's proposed tariff that would provide for complete and timely recovery of all of the costs associated with the Proposed Agreement. The Proposed Agreement constitutes a substantial, long-term financial obligation for the Company undertaken for the benefit of our customers. The

[58] R.I. Gen. Laws §39-31-7.

[59] R.I. Gen. Laws §39-31-2 establishes the purposes of the ACES Act, including "(1) Secure the future of the Rhode Island and New England economies, and their shared environment, by making coordinated, cost-effective, strategic investments in energy resources and infrastructure such that the New England states improve energy system reliability and security; enhance economic competitiveness by reducing energy costs to attract new investment and job growth opportunities; and protect the quality of life and environment for all residents and businesses."

Company emphasizes that the PUC's approval of the Proposed Agreement necessitates fully assured, complete, and timely recovery of all costs associated with the Proposed Agreement for its 20-year duration. As Witness Michael Vilbert from The Brattle Group explains in his pre-filed written testimony on behalf of the Company in this proceeding, anything less than such fully assured cost recovery can materially increase the Company's financial risk and its cost of capital, to the detriment of our customers.

V. Summary of Conclusions and Recommendations

Q. Please summarize your principal conclusions.

A. My principal conclusions are:

1) The current and future electric utility business environment requires electric distribution utilities to innovate with regard to technologies, business practices, customer offerings, and policies and regulation.
2) Incentives encourage innovation, particularly as compared to a traditional cost-of-service based regulatory framework. Providing a modest but meaningful financial incentive for innovation helps utility rate regulation better mirror the outcomes of a competitive market where firms earn higher returns from innovating and providing products and services that deliver more value for customers.
3) Rhode Island would be well served if the PUC were to facilitate innovation that is likely to provide a public benefit, including lowering the cost of energy.

4) The PUC has an extensive history of providing incentives related to a range of utility activities, with those incentives intended to foster and reward utility efforts that yield customer benefits.
5) National Grid contributed substantially to the development of an innovative solution to a major energy challenge facing Rhode Island and New England.
6) This solution, once implemented is projected to save the Company's customers approximately $110 million per year, on a levelized basis over the duration of the Proposed Agreement.

Q. Please summarize your recommendation.

A. In approving the Proposed Agreement, the PUC should also approve the Company's requested innovation incentive equal to 2.75 percent of the annual fixed contract payments under the Proposed Agreement.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

Testimony of
Michael J. Vilbert

DIRECT TESTIMONY

OF

MICHAEL J. VILBERT

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I. Introduction and Qualifications

Q. Please state your name and address for the record.

A. My name is Michael J. Vilbert. My business address is The Brattle Group, 201 Mission Street, Suite 2800, San Francisco, CA 94105.

Q. Please describe your job, experience and educational background.

A. I am a Principal of The Brattle Group, (Brattle), an economic, environmental and management consulting firm with offices in Cambridge, Washington, New York, San Francisco, London, Rome, Madrid, and Toronto. My work concentrates on financial and regulatory economics. I have worked in the areas of cost of capital, investment risk and related matters for many industries, regulated and unregulated alike, in many forums. I have testified or filed cost of capital testimony before the Arizona Corporation Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of West Virginia, the Public Utilities Commission of Ohio, the Tennessee Regulatory Authority, the Public Service Commission of Wisconsin,[1] the South Dakota Utilities Commission, the California Public Utilities Commission, the Michigan Public Service Commission, the Canadian National Energy Board, the Alberta Energy and Utilities Board, the Ontario Energy Board, and the Labrador & Newfoundland Board of Commissioners of Public Utilities. I hold a B.S. from the U.S. Air Force Academy and

[1] The appropriate compensation for imputed debt was the subject of one proceeding in Wisconsin in which Dr. Vilbert was involved.

a Ph.D. in finance from the Wharton School of Business at the University of Pennsylvania. Schedule MJV-1 of my testimony contains more information on my professional qualifications.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by The Narragansett Electric Company d/b/a National Grid (the Company) to describe how, absent fully assured cost recovery for the duration of the contract, the long-term financial obligations associated with the 20-year natural gas capacity contract at issue in this proceeding would impose increased financial risk on the Company and how that financial risk would increase the Company's cost of equity capital, which would ultimately be borne by its customers. My analysis underscores the importance of the Company's request for assurance of full cost recovery for all contract-related costs for the duration of the contract.

Q. Please summarize how you approached this task.

A. I approach this task from the perspective that the fixed payments inherent in signing long-term contracts are financial obligations similar in nature to interest and principal payments on debt and therefore, depending on the basis for cost recovery, could increase the Company's financial risk. I illustrate the potential magnitude of this increase in financial risk and its effect on the Company's cost of equity in several steps. First, I estimate the present value of the fixed contractual payments, and second, I show, for a

range of reasonable risk factors which are applied to the present value, what the magnitude of the financial risk might be. The risk factor depends on the regulatory and legislative assurance of cost recovery. Third, I determine the effect that an increase in financial risk would have on the Company's cost of equity unless the increased financial risk were offset. I understand that the Company is not seeking compensation for this increase in risk.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following schedules:

- Schedule MJV-1: Resume of Michael J. Vilbert
- Schedule MJV-2: Edison Electric Institute (EEI) article on the imputed debt methodology published by Standard & Poor's Ratings Services (S&P).

Q. How is your testimony organized?

A. Section II provides an overview of the conditions leading to the Company's application for approval of the long-term natural gas contract that will alleviate the natural gas pipeline capacity constraints into the New England market. Section III discusses why there is a potential risk transfer from the investors in new natural gas pipeline assets to the investors in the Company associated with taking on the obligation to make capacity

payments over a 20-year period.[2] The payments are equivalent to the payments on long-term debt, and consequently, may increase the Company's financial risk, depending on the degree to which full cost recovery is assured. Section IV reviews the S&P method of quantifying the amount of imputed debt that would result from the financial obligation represented by the contract payments. The calculation of the amount of imputed debt provides a method to quantify the potential financial risk imposed on the Company by the contract. Section V illustrates the potential impact of the increased financial risk on the cost of equity capital for the Company and reviews the recovery methods proposed for the contract costs. This section also discusses the overall regulatory and political context and their effect on the risk factor in the S&P imputed debt methodology. The greater the assurance of cost recovery, the lower is the applicable risk factor in the model. Section VI reviews the Company's decision not to request compensation for the increased financial because of the reliance on assurance of cost recovery. Section VII concludes the testimony.

[2] Contract payments are expected to begin in 2019 and extend through 2038.

II. Incremental Natural Gas Infrastructure in New England

Q. Why are the New England policymakers, utility regulators, and electric distribution companies (EDCs) considering incremental natural gas infrastructure to serve electric generators?

A. The Rhode Island Public Utilities Commission (PUC) recognized the impact of natural gas pipeline capacity in a recent decision:

> Half of the electricity generated in New England is from gas-fired plants, and with ninety-five percent (95%) of proposed new generation coming from gas and wind resources, the trend is toward more, not less, natural gas. During periods of peak demand, i.e. the coldest days of winter, New England suffers from the inability to import needed natural gas from neighboring states like Pennsylvania, which are plentiful in natural gas. This constraint has led to increasingly high wholesale electricity prices.[3]

Similarly, in its recent investigation of market conditions, the Massachusetts Department of Public Utilities (the Department) found sufficient evidence to arrive at the conclusion that increasing regional gas capacity will lead to lower wholesale gas and electricity prices.[4]

Specifically, the Department found that there is a "widespread conclusion that high winter electricity costs in Massachusetts and in New England in general are attributable

[3] The Narragansett Electric Company d/b/a National Grid's Proposed Standard Offer Service Rates for Residential and Commercial Groups (January through June 2015) and Industrial Group (January through March 2015), PUC Report and Order No. 21827 at 11-12 (Docket No. 4393) (February 23, 2015).

[4] D.P.U. 15-37, Order Determining Department Authority Under G.L.C. 164, §94A, October 2, 2015, (D.P.U. 15-37), at 12.

to natural gas capacity constraints."[5] Gas local distribution companies (gas LDCs) have long-term contracts with natural gas pipelines to serve their customers, so gas LDC customers in New England have faced less price volatility in recent years than have electric customers. Electric generators do not have such long-term contracts.[6] During recent winters in New England, when demand for natural gas was high, the spot price for natural gas in New England, which is the price paid by natural gas-fired electric generators without capacity contracts, increased dramatically due to a shortage of supply relative to demand.[7] See Figure 1 below. These higher gas costs increase the power costs that electric customers pay.[8]

[5] D.P.U. 15-37 at 2.

[6] This is noted in, for example, the Massachusetts Department of Energy Resources' (DOER) "Request to Open an Investigation into New, Incremental Natural Gas Delivery Capacity for Thermal Load and Electric Generation," April 2, 2015, in D.P.U. 15-37.

[7] A basis differential in gas prices is the difference in prices between Henry Hub and a specific location's price. A high basis differential is an indication of a shortage of supply relative to demand. According to data from SNL, the basis to Algonquin Citygate (Boston) was very large during the winters of 2013, 2014 and 2015 (see Figure 1). ICF International, New England Energy Market Outlook (2015) (prepared for Kinder Morgan). Figure 3, displays a similar observation.

[8] *See, e.g.*, D.P.U. 15-37 at 12.

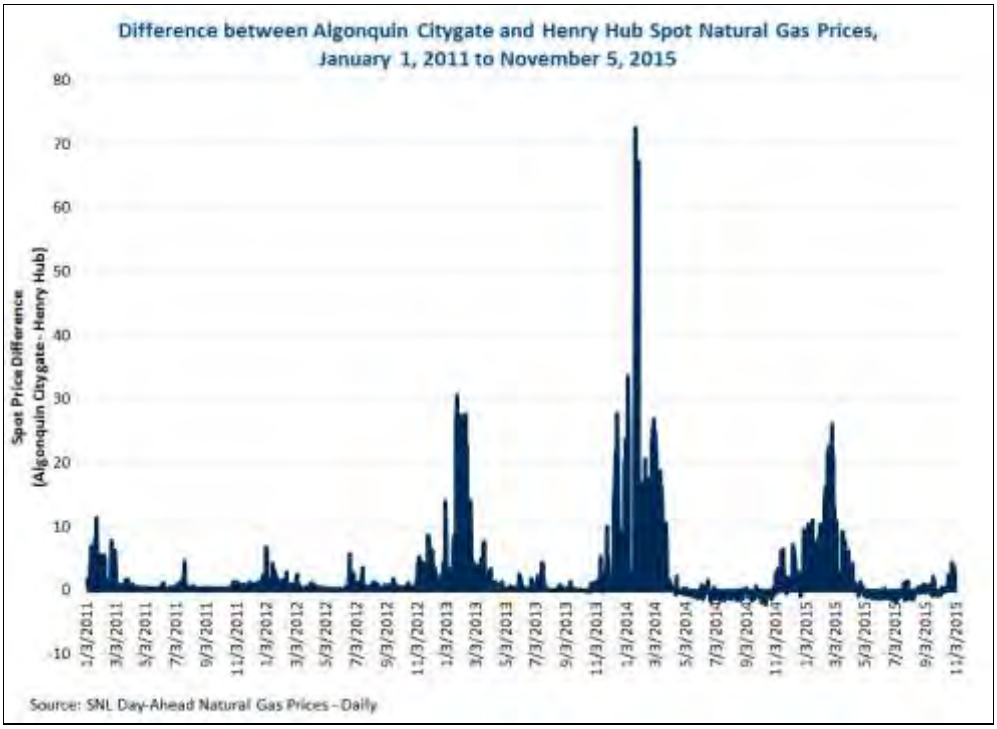

Figure 1

Q. Why aren't the constraints in natural gas pipeline capacity eliminated by the pipeline companies or indirectly by the electricity generators?

A. Company Witnesses Brennan and Allocca describe the Company's views on the current imbalance of supply and demand for natural gas infrastructure in New England. In addressing the natural gas pipeline capacity constraint as it pertains to Massachusetts, the Department in a recent order noted that:

> [the] Department finds in this Order that innovative solutions and a menu of options are required to alleviate capacity constraints and the associated downstream market price impact experienced by Massachusetts ratepayers.[9]

[9] D.P.U. 15-37 at 12.

Put differently, the Department found that pipeline capacity simply would not be expanded by the pipeline companies without new initiatives. This is because the pipeline companies will not construct new pipeline capacity without a demonstration of market demand through sufficient commitment by pipeline customers to sign long-term contracts.[10] Gas LDCs who contract for capacity and natural gas for their customers usually have the ability to pass fuel costs onto customers through fuel adjustment clauses.[11] Natural gas-fired electric generators, who sell their output into the wholesale electric market, are not assured of recovery of the cost of long-term natural gas contracts. Without assurance of cost recovery, the natural gas-fired electric generators are reluctant to sign long-term contracts required by the pipeline companies before they will construct new pipelines.

Q. Are you aware of any other EDCs elsewhere in the U.S. who have undertaken comparable agreements to secure additional long-term natural gas infrastructure to increase supply to electricity generators?

A. No. In my experience, this approach presently undertaken by the Company and its New England EDC peers is unique. Illustrating this point, the Department described the arrangement proposed by the Company's affiliates in Massachusetts as "innovative,"

[10] Before approving the construction of a pipeline, FERC requires that the proposed natural gas pipeline project demonstrate that the proposed facilities are required by the "public convenience and necessity." http://www ferc.gov/industries/gas.asp

[11] *See, e.g.*, Regulatory Research Associates, Adjustment Clauses and Rate Riders (March 2012).

and the proposals from New England EDCs appear to be the only example anywhere in the U.S. of "wires-only" EDCs (operating in restructured jurisdictions with organized electricity markets) procuring natural gas transportation infrastructure to serve electricity generators.

Q. Please briefly describe the gas infrastructure contract for which the Company seeks approval from the Commission?

A. Company Witnesses Brennan and Allocca describe the Proposed Agreement in detail. In short, the Company's Proposed Agreement is a 20-year contract for natural gas pipeline transportation capacity and storage services with gross annual contract costs to the Company of about [redacted].[12]

Q. Has the Company provided an estimate of the net benefits from the Proposed Agreements?

A. Yes. Witness Gary J. Wilmes from Black & Veatch Management Consulting LLC (Black & Veatch) on behalf of the Company summarizes the results of the benefit-cost analysis conducted for the Company.

[12] The annual contract costs are expected to [redacted].

Q. What did the Black & Veatch study find?

A. According to the economic modeling analysis conducted by Black & Veatch customer benefits are expected to exceed the cost of new pipeline capacity by a substantial margin. Black & Veatch found that the Proposed Agreement would provide *net* annual levelized economic benefits of approximately $110 million to the Company's customers in Rhode Island over the 20 years of the agreement.[13]

III. Risk Transfers in Long-Term Contracts

Q. What is the topic of this section of your testimony?

A. This section addresses why there is a transfer of risk as a result of signing long-term contracts like the Proposed Agreement and the impact of this risk transfer.

Q. How does the risk transfer referenced above occur?

A. If a pipeline has no long-term contracts, all risk associated with the recovery of the investment in the pipeline rests with the pipeline's investors. Signing long-term capacity contracts with creditworthy counterparties provides the pipeline investors with assurance of recovery of a portion of their investment through fixed periodic contract payments. In turn, the entities that sign the long-term contracts are obligated to make these payments and hence assume the financial risk inherent in making those payments.

[13] *See* Schedule GJW-3, Table 8 (Black & Veatch's Evaluation of Long-term Economic Benefits from Proposed Incremental Energy Infrastructure into New England).

Thus, part of the risk of recovery of the investment in the pipeline has been transferred from the pipeline's investors to the investors in the pipeline's counterparties in those long-term contracts.

Q. Please explain why the risk transfer from the pipeline to those who contract for capacity through signing long-term natural gas contracts is important.

A. Investing in a natural gas pipeline entails risk. A pipeline is expensive to build and is a very long-lived asset that cannot be easily relocated or repurposed. Moreover, it can be risky to operate if not properly maintained. Recovering the investment in the pipeline requires a reliable source of natural gas supply and an ongoing demand for natural gas in the delivery area.[14] As a result, natural gas pipelines are not generally constructed without the support of sufficient long-term contracts from pipeline customers.

Q. What is the effect of signing a long-term natural gas capacity contract on the Company?

A. Signing a long-term contract means that the Company has committed to pay a substantial portion of the cost of the pipeline investment over the term of the contract. In general, the contracts will not provide full cost recovery of the pipeline investment, but they will allow the pipeline to have assurance that a substantial portion of the

[14] For a discussion of the potential risks facing natural gas pipelines under North American regulations, *See, e.g.*, Paul R. Carpenter, A. Lawrence Kolbe, Steven H. Levine, and Bente Villadsen, *Shale Gas and Pipeline Risk*, Public Utilities Fortnightly, April 2012, at 20-25.

investment will be recovered. In effect, a portion of the risk of cost recovery is transferred from the pipeline companies' investors to the Company over the term of the contracts. The Company, in turn, is seeking assurances from the Commission that the Company can recover the contract costs before signing such contracts. Fundamentally, absent financial remuneration, the best possible outcome that the Company's investors can expect is to break even on cost recovery for the Proposed Agreement. With any deviation from full cost recovery over the 20-year term of the contracts, the Company may recover less than the full cost of the Proposed Agreement. If there is any possibility of less than full cost recovery over the entire term of the contracts, the Proposed Agreement has a negative expected value for the Company's investors—despite the hundreds of millions of dollars of projected net benefits for customers from the Proposed Agreement.

Q. Are you saying that the pipeline's investors have no risk during the period covered by the long-term contract?

A. No. The pipeline's investors continue to bear some of the risk, but a portion of the risk has been transferred to the Company through the long-term contract. Among the risks to the pipeline's investors is the risk that the Company may be unable to make the contract payments. This could happen in the unlikely event that the Company was to declare bankruptcy. At the end of the long-term contract, the pipeline must seek new or renewal

contracts for pipeline capacity. This risk remains with the pipeline even with a 20-year contract.

Q. If there were insufficient commitment to long-term contracts, is it likely that the pipeline would be constructed?

A. No. Absent sufficient indication of capacity demand through a willingness to sign long-term contracts, it is highly unlikely that the pipeline would be constructed because of the risk of not achieving full cost recovery. Of course, this is one reason that having the EDCs sign such contracts is being considered, and this is clear evidence that there is a transfer of risk from the pipeline investors to the entities that sign the long-term contracts.

Q. Is it important that the entities signing long-term contracts be creditworthy?

A. Yes. The pipeline's investors are relying upon the contract payments to recover their investment in the pipeline and to earn an appropriate rate of return. The strength of the balance sheets of the EDCs signing long-term contracts is critical for that reliance. If the EDCs are not creditworthy, the pipeline investors may be unwilling to proceed out of fear that the EDCs may default on their commitment. The stronger the credit rating of the EDCs signing the contracts, the more assured the pipeline will be of cost recovery.

Q. Can the Company avoid making the fixed contract payments?

A. No. The obligation to make the agreed upon contract payments is similar in nature to the requirement to make payments on debt. The interest and principal payments on debt cannot be avoided without a default or re-contracting. Similarly, the contract payments for the pipeline capacity cannot be avoided without a default, re-contracting or the expectation of being sued by the pipeline for payment. So, even if the Company faced challenges to timely recovery of the cost of the pipeline capacity from its customers, the contract payments could not be avoided.

Q. What are some regulatory mechanisms that have been used to address the risk transfer inherent in long-term capacity contracts and to compensate utilities for the risk they take on by entering into such contracts?

A. There are commonly two complementary approaches that can be adopted to address the risk transfer. First, in most cases the risk is reduced by providing for relatively assured recovery of the costs.[15] This has been done through, for example, fuel adjustment clauses that provide for recovery of costs associated with long-term contracts. Second, the financial risk has been compensated through an increase in the financial remuneration that the regulated entity receives. For example, the Wisconsin Public Service Commission increased the amount of equity included in the capital structure

[15] It is difficult to eliminate recovery risk completely, because a current regulatory decision cannot bind future regulators.

used for ratemaking purposes and thus provided financial compensation to Wisconsin Public Service for an estimated amount of imputed debt associated with long-term purchased power agreements (PPA).[16] Thus, the PUC can address the risk transferred to the Company under the Proposed Agreement by: (1) reducing the risk retained by the Company through appropriate cost recovery provisions and/or (2) providing financial compensation to the Company for any remaining financial risk.

IV. How to Evaluate the Amount of Risk Transferred

Q. How can the amount of risk transferred through signing long-term contracts be quantified?

A. The amount of risk transferred cannot be directly observed. Ideally, one might attempt to quantify the impact of the long-term contracts by calculating the difference in the estimated cost of equity for one group of publicly traded EDCs that have long-term pipeline contracts like the Proposed Agreement and the estimated cost of equity for an otherwise comparable group of EDCs that do not have such contracts. However, such companies are impossible to find for several reasons, including that these pipeline contracts proposed by the New England EDCs are unique. An alternative approach that can be applied is based on the fundamental relationship between financial leverage and risk to investors. This approach calculates a measure of increased financial leverage,

[16] *See, e.g.*, Public Service Commission of Wisconsin, Final Decision at 36-38 (Docket 6690-UR-122) (December 18, 2013) (referred to herein as the Wisconsin Decision).

referred to as imputed debt that results from long-term contract commitments, and translates that into the higher return that equity investors would require in light of the greater financial risk.

Q. Please describe this approach to measuring imputed debt and its impact on equity investors' required return?

A. As noted earlier, the financial obligation inherent in signing long-term contracts is similar in nature to the obligations of debt, but the financial obligation does not generally appear on the company's balance sheet. To assess how equity investors would likely view the effect of the long-term contracts on the EDCs' financial risk, one can employ a widely known and robust methodology for calculating the effective imputed debt associated with long-term contracts. S&P and the other credit rating entities recognize that the obligations represented by long-term contracts can have credit quality implications, and S&P has published its methodology for calculating imputed debt for electric utilities.[17] Although the published S&P methodology for calculating imputed debt was developed specifically for PPAs for certain utilities, it is a robust tool for assessing the financial risk of long-term contracts for natural gas pipeline capacity entered into by EDCs because the key issue in both cases is the impact of the fixed

[17] *See* Standard & Poor's Methodology for Imputing Debt for U.S. Utilities' Power Purchase Agreements, May 7, 2007, (S&P 2007 Report) and Standard & Poor's Key Credit Factors for the Regulated Utilities Industry, November 19, 2013 (S&P 2013 Report).

contractual payments on the effective financial leverage of the entity entering into such contracts.

S&P published its method of calculating the amount of imputed debt, and Brattle wrote an article for EEI applying S&P's method to calculate imputed debt and to demonstrate the options for addressing the increased financial risk imposed on utilities by long-term contracts (specifically, in the case of the article, PPAs).[18] Herein, I implement the same imputed debt methodology and approach for compensating utility investors for increased financial risk presented in the EEI article. The approach that my colleagues and I developed in the EEI article applies equally well to PPAs or long-term gas capacity contracts like the Proposed Agreement.

Q. Do you expect that the long-term contract payments associated with the Proposed Agreement will be required to appear on the Company's balance sheet?

A. No. While it is possible for long-term contracts to appear on a company's balance sheet, the contract would have to be considered a lease. Thus, the contract would need to convey the right to use property, plant or equipment for a stated period of time to the lessee (in this case, the Company). Even if deemed a lease, only capital leases are currently reflected on the balance sheet of the lessee, and the Proposed Agreement is

[18] Michael J. Vilbert, Bente Villadsen, and Joe Wharton, The Brattle Group, Understanding Debt Imputation Issues, June 2008 (prepared for the Edison Elec. Inst.) (the EEI article, attached as Schedule MJV-2).

unlikely to meet the criteria for being a capital lease.[19] Long-term contracts that are material but not capital leases are usually described in the notes to the financial statements.

Q. Please describe the S&P method for calculating the amount of imputed debt that results from signing long-term contracts.

A. S&P's method consists of two steps. First, calculate the present value (PV) of the fixed contract payments using a discount rate of seven percent.[20] Second, calculate the amount of imputed debt as the product of the risk factor and the PV of the fixed contract payments.[21]

Q. Why does S&P use a rate of seven percent for all imputed debt calculations?

A. To my knowledge, S&P has not stated why seven percent is the appropriate discount rate, but I believe that S&P may have decided to avoid potential controversy by using a constant discount rate for all utilities with long-term contract payments rather than trying to estimate the appropriate discount rate for each utility and PPA contract. In

[19] A lease is a capital lease if it meets any one of the following conditions: (i) the lease life exceeds 75 percent of the expected life of the asset; (ii) there is a transfer of ownership to the lessee at the end of the lease term; (iii) the lessee has an option to purchase the asset at a "bargain price" at the end of the lease term; or (iv) the present value of the lease payments, discounted at an appropriate discount rate exceeds 90 percent of the fair market value of the asset. Such leases are included on the balance sheet. *See* U.S. GAAP ASC 840-30-25-1 and ASC 840-10-25-1.

[20] S&P 2013 Report, at 14.

[21] S&P 2013 Report, at 14-1.5

principle, the correct discount rate would reflect the risk of the cash flows being evaluated but determining that discount rate would require analysis. Moreover, the appropriate discount rate would likely differ for different PPAs, and the rate would change as economic conditions and interest rates in the economy change. I follow S&P's lead and use seven percent as the discount rate in my analysis.[22]

Q. What is the risk factor?

A. The risk factor used by S&P represents an estimate of the risk of the recovery of the costs of the contracts from the utility's customers. S&P's risk factors range from 0 to 100 percent where "[r]isk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements."[23] The stronger the recovery mechanism, the smaller will be the risk factor. An independent power producer commonly faces a risk factor of 100 percent, while a regulated utility with a fuel adjustment clause commonly has a risk factor of 25 percent.[24] Thus, the firmer the regulatory or legislative assurance that a utility can recover the costs associated with a long-term contract, the lower the risk factor can be. For example, the Wisconsin Public Service Commission used a risk factor

[22] The higher the discount rate, the lower the amount of imputed debt. Notably, in S&P's stand-alone publication detailing the imputed debt methodology, S&P explained that "[w]e calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt." S&P 2007 Report, at 2. Currently, the market yield on A-rated utility debt is about 4 percent and thus is lower than the 7 percent used in the S&P 2013 Report.

[23] S&P 2007 Report, at 2-3.

[24] S&P 2007 Report, at 2-3.

of 25 percent for capacity contracts that were recovered through a fuel adjustment clause and a risk factor of 40 percent for the present value of other capacity contracts.[25] The risk factor reflects the recognition that some of the risk transferred from the pipeline to the EDC is alleviated by assurance of cost recovery by regulators or legislation. The more certain the recovery of costs from the EDC's customers, the lower the risk factor and therefore the lower the amount of imputed debt imposed on the EDC from the contract.

Q. Does the level of financial risk associated with the new long-term contracts depend on whether the rating agencies impute debt specifically related to the Proposed Agreement when evaluating the Company's credit quality?

A. No. The imputed debt methodology is a logical framework for assessing the increased financial risk associated with long-term, debt-like, off-balance-sheet obligations that utilities may carry. It is a theoretically sound framework developed by a highly reputable rating agency and one that is well known and understood by investors. The imputed debt methodology published by S&P, as explained in the article my colleagues and I wrote for EEI, can be used as the basis for measuring the increase in financial risk faced by a utility in relation to a long-term contract and the effect on the utility's cost of capital. The three major rating agencies—i.e., S&P, Moody's Investor Services, and

[25] Wisconsin Decision at 37.

Fitch Ratings—have different policies on whether or not to impute debt related to long-term contracts like PPAs, with S&P generally more likely to impute debt as a means of explicitly accounting for the financial risk associated with such long-term obligations. Whether or not one or more rating agencies impute debt related to the pipeline contracts in evaluating the credit quality of the EDCs who sign such contracts does not determine whether the imputed debt methodology is a robust one for assessing the impact of the contracts on the EDCs' financial risk.

Q. If the rating agencies do not explicitly impute debt related to the Proposed Agreement in their credit metrics for the Company, would that imply that there is no financial risk to the Company from the Proposed Agreement?

A. No. Keep in mind that the credit rating agencies are primarily concerned about the risk to investors in a company's debt. They are concerned about the risk to equity investors only to the extent that it affects the risk of full recovery for debt investors.

Q. Why might there still be a risk transfer even if the rating agencies do not explicitly impute debt related to the Proposed Agreement?

A. Although equity and debt investors share some common concerns, the risks of the two types of investments are different. Investors in a company's debt are concerned about default risk which is the risk that the promised interest and principal payments will not be made on time and in full. Equity investors are concerned about the market variability

of the return on their investment. Equity investors are "residual claimants" which means that they only receive a return *after* all other financial obligations of the firm have been met, including interest and principal repayment. In a sense, debt investors are only concerned about whether there is sufficient cash flow to make the promised debt payments irrespective of whether there is anything left for equity investors. Because debt payments as well as long-term contract payments are fixed, all variability in cash flow accrues to equity investors. Increasing the percentage and amount of additional fixed payment obligations increases the potential variability of returns to equity investors.

Q. Would you expect the credit rating agencies to impute debt related to the Proposed Agreement?

A. This question cannot be answered definitively at this time, but S&P's methodology is well known to investors and regulators. The Proposed Agreement has characteristics similar to PPA contracts and also has characteristics similar to leases for which S&P has imputed debt in the past. Specifically, the Company would commit to substantial fixed payments for the 20-year term of the contract.

Q. What factors are equity investors likely to consider in evaluating the degree to which the Proposed Agreement affects the Company's financial risk?

A. As the assurance of full cost recovery increases, the impact the Proposed Agreement will have on the Company's financial risk is reduced. In particular, the importance of legislative support is emphasized in S&P's imputed debt methodology, with S&P explaining that "we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles."[26]

Q. Can you provide an example of the type of legislative support you have in mind?

A. Yes. The legislative support for cost recovery that many states have provided for utility securitizations is such an example. During the period of deregulation of the electric generation portion of the electric industry, securitization was used to recover the costs stranded by the change in regulatory policy. The idea was that the cost to customers for recovery of the utility's stranded costs could be reduced if bonds could be issued bearing a low interest rate. In general, bonds with strong credit ratings have a lower rate of interest, and the highest credit rating is an AAA/Aaa rating. Achieving an AAA/Aaa rating for the securitized debt generally required that the revenues to make the principal and interest payments on the bonds be collected through a non-bypassable special charge to the utility's customers. In addition, the special charge would be automatically

[26] S&P 2007 Report at 4.

adjusted to insure recovery of the required bond payments. Further security for the bonds was provided by a legislative guarantee that the collection of the special charge would not be hindered by either the state or the public utility commission. The bonds would be issued by a bankruptcy remote Special Purpose Entity (SPE) whose sole purpose was to issue the bonds and make the required payments to investors.

In general, all of these provisions were required to achieve an AAA/Aaa credit rating. The implication is that achieving a risk factor of zero for recovery of the costs of the long-term natural gas pipeline capacity contract would require similar cost recovery guarantees, particularly specific legislative authorization of full cost recovery.

Q. Please describe the relevant context for the Company's proposed recovery of the cost of the Proposed Agreement?

A. The Company proposes to sign the Proposed Agreement in order to deliver net economic benefits to its customers, which Black & Veatch have estimated to be several hundred million dollars in present value over the life of the contract.[27] Nonetheless, the arrangement of EDCs securing pipeline capacity to serve electricity generators is a novel one without any history of consistent full cost recovery for the EDCs—not only in New England but in any restructured state in the U.S. Moreover, political support for new gas infrastructure has shifted with changing gubernatorial administrations in New

[27] *See* Testimony of Gary J. Wilmes.

England, and certain stakeholders either dismiss the need for new pipeline capacity or oppose the arrangement of EDCs contracting for the pipeline capacity.[28] The variation in political support for the Cape Wind project is a recent example from nearby Massachusetts that highlights how projects with initially strong political support can fall out of favor over time.[29] In general, it is important to recognize that it is difficult if not impossible for the current regulators to bind future regulatory policy. Equity investors would likely consider this entire context in evaluating whether full recovery of the Proposed Agreement's costs is guaranteed over the entire term of the contracts.

Q. Can you provide an example where long-term contract obligations substantially contributed to a utility's financial distress because of insufficient regulatory guarantees and a challenging political context?

A. Yes. In the early 1990's, Niagara Mohawk Power Company (NMPC) in New York was required to purchase electric power from independent power producers (IPPs) at a minimum of 6 cents/kwh. The requirement to purchase power was the result of a combination of the Public Utilities Regulatory Policy Act (PURPA) and New York's so-called ~~"~~Six-Cent law." In time, NMPC had been required to purchase power in excess

[28] *See, e.g,*. Paul J. Hibbard & Craig P. Aubuchon, Analysis Group, Inc., Power System Reliability in New England – Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas, November 2015 (prepared on behalf of the Massachusetts Attorney General).

[29] Support for Cape Wind was initially strong, in part because of the renewable and clean power aspects of the project but later declined because of the cost of the project as well as the aesthetics of the wind turbines off the coast of Cape Cod.

of its peak demand. Ultimately, the New York Public Service Commission (NY PSC) denied NMPC's request for rate relief to cover the burgeoning cost of its Six-Cent law contracts, resulting in a credit rating downgrade to BB+, a non-investment grade rating. NMPC's financial distress came about despite the fact that the NY PSC and the State of New York were partially, if not entirely, responsible for adopting the policies that required NMPC to enter into the contracts.

Q. What is the implication of NMPC's experience with the Six-Cent law?

A. Despite being required to sign long-term contracts for electric power by the State of New York, NMPC was unable to fully recover the costs of the contracts. The inability to recover the costs of these contracts led to a credit rating downgrade and financial distress for NMPC, including earning substantially below its authorized rate of return. This is an example of the risk associated with long-term financial obligations when circumstances and regulators change. Notably, NMPC's severe financial distress and the negative impacts on equity investors are not from long ago and far away. Rather, NMPC's Six-Cent law experience happened within the past two decades, in the U.S. Northeast, to a utility subsequently acquired by the Company's own parent, National Grid plc.

Q. Are there additional risks that investors would likely consider?

A. Yes. Given the lack of precedent in Rhode Island governing the procurement of gas capacity contracts by an EDC, legal challenges to state regulators' approvals of any gas capacity contracts are possible. While the Company has sought to limit its exposure to the risk of litigation in contract provisions, it may not be possible to fully insulate against the risk that legal challenges will upend regulators' initial decisions on contract approvals and cost recovery without affecting the Company's contract payment obligations. Investors may see risk in the possibility that the regulatory decisions that approved the contracts and their cost recovery could be overturned by the courts. Looking out over the next two decades during which the Proposed Agreement will be in effect, regulatory and economic conditions may change in ways not always anticipated. It is unwise to believe that they will not or could not.

V. Illustration of Potential Impact of Proposed Agreement on the Company's Cost of Capital

Q. Please describe how you quantified the potential impact of the Proposed Agreement on the Company's financial risk and cost of capital.

A. I first calculated a level of imputed debt corresponding to the Proposed Agreement using the aforementioned S&P methodology for a range of reasonable risk factors. With these levels of imputed debt, I then calculated the effect on the Company's cost of equity from

having greater financial leverage from having both actual and imputed debt in its capital structure.

Q. What is the range of risk factors related to the Proposed Agreement that you used in your analysis?

A. For the lower bound, I assume that the PUC will provide a degree of assurance of full cost recovery for the duration of the Proposed Agreement that would support a zero or near-zero risk factor. I consider that the Company's proposed cost recovery mechanism is similar in nature to the recovery for PPA contracts that are recovered through fuel adjustment mechanism and such contracts generally receive a 25 percent risk factor from S&P. Specifically, a risk factor of 25 percent is consistent with the risk factor S&P uses in cases where the "regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs"[30] and with what, for example, the Wisconsin Public Service Commission determined appropriate for PPAs recovered through a fuel adjustment clause.[31] As such, when I evaluated the potential effects of the Proposed Agreement on the Company's cost of capital, I look at risk factors of zero, 5 percent and 25 percent.[32]

[30] Standard & Poor, Key Credit Factors For The Regulated Utilities Industry, at 14 (November 19, 2013).

[31] Wisconsin Decision at 37.

[32] At a 0 percent risk factor, the imputed debt analysis yields no impact on the Company's cost of capital. A 5 percent risk factors is evaluated as a near-zero risk factor.

Q. How can the potential effect of the Proposed Agreement on the Company's cost of capital be considered?

A. The methods are explained in detail in the article my colleagues and I wrote for EEI, which is included as Schedule MJV-2, but in the interest of brevity, the methods are summarized here. First, the financial risk inherent in the estimated amount of imputed debt can be estimated and recognized through a higher required return on equity. Second, the impact of the long-term contracts could be estimated as the adjustment to the equity ratio that is needed in the regulatory capital structure to ensure the EDC's overall weighted-average return is the same before and after signing the long-term contracts. This could be accomplished by substituting equity for currently outstanding debt so that the regulatory capital structure without consideration of imputed debt has more equity and less debt than before the contract.

Q. Please describe how the amount of imputed debt is estimated.

A. First, I determine the present value of 20 years of capacity payments of approximately [redacted] per year using a discount rate of 7 percent. The present value in 2016 of the 20 years of contract payments is roughly [redacted]. Second, I illustrate the size of the imputed debt at risk factors of 5 percent and 25 percent.

Q. Once the magnitude of imputed debt is calculated, how is the impact on the Company's cost of capital determined?

A. Having determined the amount of imputed debt, I can use that amount to determine how large the financial remuneration would need to be to ensure that the imputed debt does not put the Company in an unfavorable position for attracting equity capital relative to investments in comparable companies without such imputed debt. Following the same approach that was described in detail in the EEI article, I add the amount of imputed debt to the Company's total (regulatory) capitalization as additional debt and then ensure that the weighted-average cost of capital on the invested capital (including imputed debt) is the same as it would have been without the addition of imputed debt. This requires an increase in the allowed ROE because the percentage of equity in the capital structure is less when imputed debt is recognized. This increase in the allowed ROE is necessary because of the fact that a company's after-tax weighted-average cost of capital (ATWACC)[33] is constant for changes in capital structure within a broad middle range of capital structures for the companies in an industry.[34]

[33] We refer to the ATWACC to distinguish it from the regulatory weighted-average cost of capital (the WACC) which is the weighted average of the *after-tax* cost of equity and the *pre-tax* cost of debt. For the ATWACC, the cost of equity and the cost of debt are both after-tax values.

[34] For a complete discussion of this topic, *see* The Brattle Group, The Effect of Debt on the Cost of Equity in a Regulatory Setting, January 2005 (prepared for the Edison Elec. Inst.).

Q. What are the key assumptions in your calculations?

A. Table 1 shows the key assumptions used. Rate base information, the regulatory capital structure and the cost of each component of the capital structure were obtained from the Company's most recent electric earnings report.[35] The present value of the Company's capacity payments under the Proposed Agreement is about [redacted]. I estimate the present value of the capacity payments as of the beginning of 2016 even though the contract payments are not expected to begin until 2019.[36]

[35] *See* The Narragansett Electric Company's Electric Earnings Report for the twelve-month period ended December 31, 2015 (Docket No. 4323) (submitted May 2, 2016).

[36] The present value of the contract payments would be larger in 2019 but the rate base is also expected to be larger. To maintain consistency, I use the 2016 present value with the most recent information on the rate base.

Table 1: Key Assumptions and Illustrative Imputed Debt[37]

Assumptions ($ in millions)	NECO
Capacity Payment, 2019	[redacted]
Capacity Payment, 2020	
Capacity Payment, 2021	
Capacity Payment, 2022-38	
Contract Length (years)	20
Discount Rate	7.00%
Present Value of Contract, as of 2016	[redacted]
Rate Base	$655
Debt %	50.71%
Preferred %	0.15%
Equity %	49.14%
Cost of Debt	4.90%
Cost of Preferred	4.50%
Cost of Equity	9.50%
Tax Rate	35.0%
After-Tax Weighted Average Cost of Capital	6.29%

Q. What is the amount of imputed debt and increase in equity return required to compensate for the increase in financial risk?

A. Table 2 shows a range for the imputed debt of about [redacted] corresponding to a risk factor range of 5 percent to 25 percent. At a risk factor of zero, there would be no imputed debt. Table 2 also shows the increase in the return on equity

[37] The contract payments are based on the costs reported in the Black & Veatch study sponsored by Witness Gary J. Wilmes. The rate base, cost of capital, and capital structure assumptions are from the Company's calendar year 2015 Electric Earnings Report in Docket No. 4323.

necessary to compensate for the increased financial risk. At risk factors of 5 percent and 25 percent, the Proposed Agreement would require an increase in the Company's before-tax dollar return on equity by about [redacted], respectively, on a levelized basis over the 20 years of the contract. On an after-tax basis, the required increase in levelized equity return is about [redacted] dollars annually during the contract life at risk factors of 5 percent and 25 percent, respectively.[38]

Table 2: Range of Imputed Debt Values ($ million)[39]

[1] Risk Factor	0%	5%	25%
[2] Imputed Debt	$0.00	[redacted]	
[3] Additional Return (Before-Tax), Levelized	$0.00		
[4] Additional Return (After-Tax), Levelized	$0.00		

Q. Please explain the concept of keeping the ATWACC constant in more detail.

A. Investors in a regulated company expect to earn a rate of return on their invested capital equal to the market-determined ATWACC. If the ATWACC is kept constant, the

[38] The levelized values reported are for compensation coinciding with the 20-year contract payments beginning in 2019.

[39] Imputed debt is equal to the present value of contract payments shown in Table 1 multiplied by the risk factor. The additional return required to maintain a constant ATWACC for each year from 2017 through 2038 is calculated following the methodology detailed in Schedule MJV-2 (and illustrated in Table 4 in Schedule MJV-2), and levelized over the 20-year contract period at a discount rate of 7 percent.

regulatory capital structure of the utility can be changed, but the cost to customers will be unchanged. Investors will be fairly compensated at the new capital structure. Signing long-term contracts can impose imputed debt on the utility which effectively changes the regulatory capital structure, i.e., there is now a higher percentage of debt (actual and imputed) in the capital structure than before signing the contracts. Restoring investors (debt and equity investors) to their previous expected level of compensation requires changing the allowed return on equity or restoring the capital structure to the ratios of debt and equity in place prior to inclusion of imputed debt.[40]

V. The Company's Request for Cost Recovery and Implications for Financial Remuneration

Q. Please describe the concept of financial remuneration linked to utilities' long-term contract obligations?

A. I understand that in Rhode Island legislation provides for "financial remuneration and incentives" in the context of certain long-term renewable energy contracts executed by the Company. Specifically, the statute explains that the purpose of such remuneration is to "compensate the electric distribution company for accepting the financial obligation of the long-term contracts."[41] This explanation mirrors the findings of my analysis

[40] I am implicitly assuming that the required return on the outstanding debt does not change so that restoring the ATWACC requires an adjustment to the allowed ROE.

[41] R.I. Gen. Laws § 39-26.1-4.

above that long-term contracts, as debt-like financial obligations, can increase an EDC's financial risk and its cost of capital. In this context, financial remuneration is monetary compensation provided to EDC shareholders to address the increase in their cost of capital resulting from long-term contract obligations.

Q. Is the Company requesting financial remuneration based on financial risk created by the Proposed Agreement?

A. No. The Company is not requesting any financial remuneration based on the potential effect of the long-term contract on its financial risk and cost of capital. Rather, the Company requests the PUC's assurance of full recovery of all costs related to the Proposed Agreement over the duration of the contract. That is, the Company requests that the PUC provide for a cost recovery mechanism and supportive regulatory context sufficient to warrant a zero or very nearly zero percent risk factor.

Q. Please describe the importance of assurance from the PUC of full cost recovery for the duration of the Proposed Agreement.

A. I have demonstrated above that the Proposed Agreement could substantially increase the Company's financial risk and cost of equity capital if investors perceive a non-zero risk related to cost recovery. As shown above, even at a very low risk factor (i.e., 5 percent) the impact on the Company's effective financial leverage and its cost of equity is material—specifically an annual increase of about [redacted] in before-tax equity

return over the 20 years of the contract. The reason that the required financial offset for the increased financial risk is relatively large even at low risk factors is because the present value of the contract payments is nearly as large as the Company's rate base. The present value of the contract payments is [redacted] compared to a rate base of about $655 million.

Q. Is providing a financial incentive for innovation a substitute for compensation for financial risk?

A. No. Compensation for financial risk is simply recognition that there is a risk transfer associated with signing long-term contracts for new natural gas pipeline capacity. In a sense, the compensation requested for financial risk merely restores the Company's investors' risk-return tradeoff to where it was prior to signing the contracts.

VI. Conclusion

Q. What do you conclude from your analysis of the potential financial risk and cost of capital implications of the Proposed Agreement?

A. I summarize my conclusions as follows:

- Long-term contracts like the Proposed Agreement constitute a significant transfer of risk from investors in pipeline companies to their counterparties, in this case the Company.
- The Proposed Agreement creates long-term, debt-like financial obligations that, like actual long-term debt, can increase the Company's financial risk and affect its cost of equity capital.

- The imputed debt methodology published by S&P provides a robust framework for quantifying the potential for increased financial risk from the Proposed Agreement and the effect on the Company's cost of equity capital.
- Investors will likely consider the first-of-a-kind nature of the Proposed Agreement, the political controversy in New England over the proposal for new natural gas infrastructure, and other factors related to the prospects for full cost recovery over the duration of the Proposed Agreement.
- Using non-zero risk factors, the magnitude of the Proposed Agreement's costs increases the Company's financial risk and its cost of equity capital—a cost which is ultimately borne by customers.
- As such, it is imperative that the Commission provide the most rigorous possible assurance of full cost recovery for the duration of the Proposed Agreement, so that a zero or near-zero risk-factor is appropriate.
- In expectation of such assurance, the Company is not seeking any financial remuneration based on financial risk imposed by the Proposed Agreement.

Q. Does this conclude your testimony?

A. Yes.

Schedule MJV-1
Curriculum Vitae

APPENDIX A:

QUALIFICATIONS OF MICHAEL J. VILBERT

Dr. Michael J. Vilbert is Office Director of The Brattle Group's San Francisco office and has 20 years of experience as an economic consultant. He is an expert in cost of capital, financial planning and valuation who has advised clients on these matters in the context of a wide variety of investment and regulatory decisions. In the area of regulatory economics, he has testified or submitted testimony on the cost of capital for regulated companies in the water, electric, natural gas and petroleum industries in the U.S. and Canada. His testimony has addressed the effect of regulatory policies such as decoupling or must-run generation on a regulated company's cost of capital and the appropriate way to estimate the cost of capital for companies organized as Master Limited Partnerships. He analyzed issues associated with situations imposing asymmetric risk on utilities, the prudence of purchased power contracts, the economics of energy conservation programs, the appropriate incentives for investment in electric transmission assets and the effect of long-term purchased power agreements on the financial risk of a company. He has served as a neutral arbitrator in a contract dispute and analyzed the effectiveness of a company's electric power supply auction. He has also estimated economic damages and analyzed the business purpose and economic substance of tax related transactions, valued assets in arbitration for purchase at the end of the contract, estimated the stranded costs of resulting from the deregulation of electric generation and from the municipalization of an electric utility's distribution assets and addressed the appropriate regulatory accounting for depreciation and goodwill.

He received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania, an MBA from the University of Utah, an M.S. from the Fletcher School of Law and Diplomacy, Tufts University, and a B.S. degree from the United States Air Force Academy. He joined The Brattle Group in 1994 after a career as an Air Force officer, where he served as a fighter pilot, intelligence officer, and professor of finance at the Air Force Academy.

REPRESENTATIVE CONSULTING EXPERIENCE

- Dr. Vilbert served as the consulting expert in several cases for the U.S. Department of Justice and the Internal Revenue Service regarding the business purpose and economic substance of a series of tax related transactions. These projects required the analysis of a complex series of financial transactions including the review of voluminous documentary evidence and required expertise in financial theory, financial market as well as

accounting and financial statement analysis.

- In a securities fraud case, Dr. Vilbert designed and created a model to value the private placement stock of a drug store chain as if there had been full disclosure of the actual financial condition of the firm. He analyzed key financial data and security analysts'= reports regarding the future of the industry in order to recreate pro forma balance sheet and income statements under a variety of scenarios designed to establish the value of the firm.

- For pharmaceutical companies rebutting price-fixing claims in antitrust litigation, Dr. Vilbert was a member of a team that prepared a comprehensive analysis of industry profitability. The analysis replicated, tested and critiqued the major recent analyses of drug costs, risks and returns. The analyses helped develop expert witness testimony to rebut allegations of excess profits.

- For an independent electric power producer, Dr. Vilbert created a model that analyzed the reasonableness of rates and costs filed by a natural gas pipeline. The model not only duplicated the pipeline=s rates, but it also allowed simulation of a variety of Awhat if@ scenarios associated with cost recovery under alternative time patterns and joint cost allocations. Results of the analysis were adopted by the intervenor group for negotiation with the pipeline.

- For the CFO of an electric utility, Dr. Vilbert developed the valuation model used to support a stranded cost estimation filing. The case involved a conflict between two utilities over the responsibility for out-of-market costs associated with a power purchase contract between them. In addition, he advised and analyzed cost recovery mechanisms that would allow full recovery of the stranded costs while providing a rate reduction for the company=s rate payers.

- Dr. Vilbert has testified as well as assisted in the preparation of testimony and the development of estimation models in numerous cost-of-capital cases for natural gas pipeline, water utility and electric utility clients before the Federal Energy Regulatory Commission (AFERC@) and state regulatory commissions. These have spanned standard estimation techniques (e.g., Discounted Cash Flow and Risk Positioning models). He has also developed and applied more advanced models specific to the industries or lines of business in question, e.g., based on the structure and risk characteristics of cash flows, or based on multi-factor models that better characterize regulated industries.

- Dr. Vilbert has valued several large, residual oil-fired generating stations to evaluate the possible conversion to natural gas or other fuels. In these analyses, the expected pre- and post-conversion station values were computed using a range of market electricity and fuel cost conditions.

- For a major western electric utility, Dr. Vilbert helped prepare testimony that analyzed the prudence of QF contract enforcement. The testimony demonstrated that the utility had not been compensated in its allowed cost of capital for major disallowances stemming from QF contract management.

- Dr. Vilbert analyzed the economic need for a major natural gas pipeline expansion to the Midwest. This involved evaluating forecasts of natural gas use in various regions of the United States and the effect of additional supplies on the pattern of natural gas pipeline use. The analysis was used to justify the expansion before the FERC and the National Energy Board of Canada.

- For a Public Utility Commission in the Northeast, Dr. Vilbert analyzed the auction of an electric utility=s purchase power agreements to determine whether the outcome of the auction was in the ratepayers= interest. The work involved the analysis of the auction procedures as well as the benefits to ratepayers of transferring risk of the PPA payments to the buyer.

- Dr. Vilbert led a team tasked to determine whether bridge tolls were "just and reasonable" for a non-profit port authority. Determination of the cost of service for the authority required estimation of the value of the authority's assets using the trended original cost methodology as well as evaluation of the operations and maintenance budgets. Investment costs, bridge traffic information and inflation indices covering a 75 year period were utilized to estimate the value of four bridges and a passenger transit line valued in excess of $1 billion.

- Dr. Vilbert helped a recently privatized railroad in Brazil develop an estimate of its revenue requirements, including a determination of the railroad=s cost of capital. He also helped evaluate alternative rate structures designed to provide economic incentives to shippers as well as to the railroad for improved service. This involved the explanation and analysis of the contribution margin of numerous shipper products, improved cost analysis and evaluation of bottlenecks in the system.

- For a utility in the Southeast, Dr. Vilbert quantified the company=s stranded costs under several legislative electric restructuring scenarios. This involved the evaluation of all of the company=s fossil and nuclear generating units, its contracts with Qualifying Facilities and the prudence of those QF contracts. He provided analysis concerning the impact of securitizing the company=s stranded costs as a means of reducing the cost to the ratepayers and several alternative designs for recovering stranded costs.

- For a recently privatized electric utility in Australia, Dr. Vilbert evaluated the proposed regulatory scheme of the Australian Competition and Consumer Commission for the company=s electric transmission system. The evaluation highlighted the elements of the

proposed regulation which would impose uncompensated asymmetric risks on the company and the need to either eliminate the asymmetry in risk or provide additional compensation so that the company could expect to earn its cost of capital.

- For an electric utility in the Southwest, Dr. Vilbert helped design and create a model to estimate the stranded costs of the company=s portfolio of Qualifying Facilities and Power Purchase contracts. This exercise was complicated by the many variations in the provisions of the contracts that required modeling in order to capture the effect of changes in either the performance of the plants or in the estimated market price of electricity.

- Dr. Vilbert helped prepare the testimony responding to a FERC request for further comments on the appropriate return on equity for electric transmission facilities. In addition, Dr. Vilbert was a member of the team that made a presentation to the FERC staff on the expected risks of the unbundled electric transmission line of business.

- Dr. Vilbert and Mr. Frank C. Graves, also of The Brattle Group, prepared testimony evaluating an innovative Canadian stranded cost recovery procedure involving the auctioning of the output of the province=s electric generation plants instead of the plants themselves. The evaluation required the analysis of the terms and conditions of the long-term contracts specifying the revenue requirements of the plants for their entire forecasted remaining economic life and required an estimate of the cost of capital for the plant owners under this new stranded cost recovery concept.

- Dr. Vilbert served as the neutral arbitrator for the valuation of a petroleum products tanker. The valuation required analysis of the Jones Act tanker market and the supply and demand balance of the available U.S. constructed tanker fleet.

- Dr. Vilbert evaluated the appropriate Abareboat@ charter rate for an oil drilling platform for the renewal period following the end of a long-term lease. The evaluation required analysis of the market for oil drilling platforms around the world including trends in construction and labor costs and the demand for platforms in varying geographical environments.

- Dr. Vilbert and Dr. Villadsen, also of The Brattle Group, evaluated the offer to purchase the assets of Pentex Alaska Natural Gas Company, LLC on behalf of the Western Finance Group for presentation to the Board of the Alaska Industrial Development and Export Authority. The report compared the proposed purchase price with selected trading and transaction multiples of comparable companies.

PRESENTATIONS

"Moving Toward Value in Utility Compensation – Shareholder Value Concept," with A. Lawrence Kolbe, California PUC Workshop, June 13, 2016.

"Natural Gas Pipeline FERC ROE," INGAA Rate of Return Seminar, with Mike Tolleth, March 23, 2016.

"The Cost of Capital for Alabama Power Company," Public Service Commission public meeting, July 17, 2013.

"An Empirical Study of the Impact of Decoupling on the Cost of Capital," Center for Research in Regulated Industries, Shawnee on Delaware, PA, May 17, 2013.

"Point – Counterpoint: The Regulatory Compact and Pipeline Competition," with (Jonathan Lesser, Continental Economics), Energy Bar Association, Western Meeting, February 22, 2013

"Introduction to Retail Rates," presented to California Water Services Company, 18-19 November 2010.

"Impact of the Ongoing Economic Crisis on the Cost of Capital of the U.S. Utility Sector", National Association of Water Companies: New York Chapter, Albany, NY, May 21, 2009.

"Impact of the Ongoing Economic Crisis on the Cost of Capital of the U.S. Utility Sector", New York Public Service Commission, Albany, NY, April 20, 2009.

ACurrent Issues in Explaining the Cost of Capital to Utility Commissions@ Cost of Capital Seminar, Philadelphia, PA, 2008.

ARevisiting the Development of Proxy Groups and Relative Risk Analysis,@ Society of Utility and Regulatory Financial Analysts: 39th Financial Forum, April 2007.

ACurrent Issues in Estimating the Cost of Capital,@ *EEI Electric Rates Advanced Course*, Madison, WI, 2006, 2007, 2008, 2009, 2010 and 2011.

ACurrent Issues in Cost of Capital,@ with Bente Villadsen, *EEI Electric Rates Advanced Course*, Madison, WI, 2005.

ACost of Capital - Explaining to the Commission - Different ROEs for Different Parts of the Business,@ *EEI Economic Regulation & Competition Analysts Meeting*, May 2, 2005.

ACost of Capital Estimation: Issues and Answers,@ *MidAmerican Regulatory Finance Conference*, Des Moines, IA, April 7, 2005.

AUtility Distribution Cost of Capital,@ *EEI Electric Rates Advanced Course*, Madison, WI, July 2004.

ANot Your Father=s Rate of Return Methodology,@ *Utility Commissioners/Wall Street Dialogue*, NY, May 2004.

AIssues for Cost of Capital Estimation,@ with Bente Villadsen, *Edison Electric Institute Cost of Capital Conference*, Chicago, IL, February 2004.

AUtility Distribution Cost of Capital,@ *EEI Electric Rates Advanced Course*, Bloomington, IN, 2002, 2003.

ARTICLES

"The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation," prepared for The Energy Foundation by Michael J. Vilbert, Joseph B. Wharton, Charles Gibbons, Melanie Rosenberg, and Yang Wei Neo, March 20, 2014.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, Bente Villadsen, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the Australian Energy Regulator and the Economic Regulation Authority, Western Australia, February 2013.

"Survey of Cost of Capital Practices in Canada," (with Bente Villadsen and Toby Brown), prepared for British Columbia Utilities Commission, May 2012.

"Economic Impact on City of Portland of Allocation of Remediation Costs of Portland Harbor Superfund Site," with Professor David Sunding, March 2012.

"The Impact of Decoupling on the Cost of Capital – An Empirical Study," Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg, and Toby Brown, Discussion Paper, *The Brattle Group*, March 2011.

"Review of Regulatory Cost of Capital Methodologies," (with Bente Villadsen and Matthew Aharonian), Canadian Transportation Agency, September 2010.

"Understanding Debt Imputation Issues,@ by Michael J. Vilbert, Bente Villadsen and Joseph B. Wharton, *Edison Electric Institute*, August 2008.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," by A. Lawrence Kolbe, Michael J. Vilbert and Bente Villadsen, *Public Utilities Fortnightly*, August 2005.

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," by A. Lawrence Kolbe, Michael J. Vilbert, Bente Villadsen and The Brattle Group, *Edison Electric Institute,* April 2005.

"Flaws in the Proposed IRS Rule to Reinstate Amortization of Deferred Tax Balances Associated with Generation Assets Reorganized in Industry Restructuring," by Frank C. Graves and Michael J. Vilbert, white paper for *Edison Electric Institute* (EEI) to the IRS, July 25, 2003.

TESTIMONY

Prepared direct testimony and supporting exhibits before the Federal Energy Regulatory Commission, Docket No. RP16-440-000, on behalf of ANR Pipeline Company, regarding the appropriate ROE to allow for its regulated natural gas pipeline assets, January 2016.

Pre-filed direct testimony before the Massachusetts Department of Public Utilities on behalf of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid regarding the risk transfer inherent in signing long-term contracts for natural gas pipeline capacity, Docket No. D.P.U. 16-05, January 2016.

Direct testimony before the Michigan Public Service Commission on behalf of the DTE Electric Company (Case No. U-18014) on the cost of capital for DTE Electric Company's regulated electric assets, January 2016.

Rebuttal testimony before the Public Utility Commission of Texas on behalf of Ovation Acquisition I, L.L.C., Ovation Acquisition II, L.L.C., and Shary Holdings, L.L.C. concerning the adequacy of Oncor Electric Distribution Company's (Oncor) liquidity, access to capital and financial risk with regard to the proposed restructuring of Oncor, PUC Docket No. 451888, December, 2015.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the DTE Gas Company (Case No. U-17799) on the cost of capital for DTE Gas Company's natural gas distribution assets, December 2015 and May 2016.

Prepared direct testimony before the Federal Energy Regulatory Commission, Docket No. ER15-2594-000, on behalf of South Central MCN, LLC, regarding the appropriate ROE to include in the transmission rate formula (Formula Rate) to establish an annual transmission revenue requirement (ATRR) for transmission service over facilities that SCMCN will own in the Southwest Power Pool, Inc. (SPP) region, September 2015.

"Report on Gas LDC multiples," with Bente Villadsen, *Alaska Industrial Development and Export Authority*, May 2015.

Direct and reply testimony before the Regulatory Commission of Alaska on behalf of Cook Inlet Natural Gas Storage Alaska, LLC, Docket No. U-15-016 on the appropriate allocation of the

proceeds from the sale of excess Found Native Gas discovered incidental to the construction of the storage facility, April 2015 and July 2015.

Direct testimony before the Michigan Public Service Commission on behalf of the Detroit Edison Electric Company (Case No. U-17767) on the cost of capital for DTE's electric utility assets, December 2014.

Direct and rebuttal testimony before the Washington Utilities and Transportation Commission on behalf of Puget Sound Energy, Inc. Docket Nos. UE-130137 and UG-130138 (consolidated) remand proceeding with regard to the effect of decoupling on the cost of capital, November 2014 and December 2014.

Initial and Reply Statement of Position before the Public Utilities Commission of Hawaii In the Matter of Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2013-0141, with Dr. Toby Brown and Dr. Joseph B. Wharton, May 2014 and September 2014.

Direct and rebuttal testimony before the Pennsylvania Public Utility Commission on behalf of Metropolitan Edison Company (Docket No. R-2014-2428745), Pennsylvania Electric Company (Docket No. R-2014-2428743), Pennsylvania Power Company (Docket No. R-2014-2428744), and West Penn Power Company (Docket No. R-2014-2428742) regarding the appropriate cost of common equity for the companies, September 2014 and December 2014.

Direct and rebuttal testimony before the Public Service Commission of West Virginia in the Matter of the Application of Monongahela Power Company and The Potomac Edison Company, Case No. 14-0702-E-42T for approval of a general change in rates and tariffs, June 2014 and October 2014.

Direct testimony before the Public Utilities Commission of Ohio in the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2012 Under the Electric Security Plans of Ohio on behalf of the Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 14-0828-EL-UNC, May 2014.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER14-1332-000, on behalf of DATC Path 15, LLC, regarding the appropriate ROE to include in the Submission of Revisions to Appendix I in TO Tariff Reflecting Updated TRR to be Effective February, 2014.

Direct testimony, rebuttal testimony and sur-surrebuttal testimony before the Arkansas Public Service Commission regarding the appropriate ROE to allow In the Matter of the Application of SourceGas Arkansas Inc., Docket No. 13-079-U for Approval of a General Change in Rates, and Tariffs, September 2013, March 2014, and April 2014.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER13-2412-000, on behalf of Trans Bay Cable LLC, regarding the appropriate ROE to include in the Submission of Revisions to Appendix I of the Trans Bay Transmission Owner Tariff to be Effective 11/23/2013, September 2013.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER13-2412-000, on behalf of Trans Bay Cable LLC, regarding the appropriate ROE to include in the Submission of Revisions to Appendix I of the Trans Bay Transmission Owner Tariff to be Effective 11/23/2013, September 2013.
Presentation on behalf of Alabama Power Company with regard to the appropriate cost of capital for the Rate Stabilization and Equalization mechanism, Dockets 18117 and 18416, July 2013.

Direct testimony before the Public Utilities Commission of Ohio in the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2012 Under the Electric Security Plans of Ohio on behalf of the Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 13-1147-EL-UNC, May 2013.

Expert Report, with A. Lawrence Kolbe and Bente Villadsen, on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of the behalf of oil pipeline in arbitration, April 2013.

Direct and Rebuttal testimony before the Public Utilities Commission of the State of Colorado on behalf of Rocky Mountain Natural Gas LLC regarding the cost of capital for an intrastate natural gas pipeline, Docket No. 13AL-143G, with Advice Letter No. 77, January 2013 and October 2013.

Rebuttal Testimony before the Public Utilities Commission of the State of California on behalf of Southern California Edison regarding Application 12-04-015 of Southern California Edison Company (U 338-E) For Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2013 and to Reset the Annual Cost of Capital Adjustment Mechanism , August 2012.

Direct testimony and supporting exhibits on behalf of Transcontinental Gas Pipeline Company, LLC, before the Federal Energy Regulatory Commission, on the Cost of Capital for Interstate Natural Gas Pipeline assets, Docket No. RP12-993-000, August 2012.
Direct Testimony before the North Carolina Utilities Commission on behalf of Cardinal Pipeline Company LLC, regarding the cost of capital for an intrastate natural gas pipeline, Docket G-39, Sub 28, August 2012.

Joint Rebuttal Testimony before the California Public Utility Commission on behalf of California American Water Company, regarding Application of California-American Water Company (U210W) for Authorization to increase its Revenues for Water Service, Application 10-07-007, and In the Matter of the Application of California-American Water Company

(U210W) for an Order Authorizing and Imposing a Moratorium on New Water Service Connections in its Larkfield District, Application 11-09-016, August 2012.

Direct testimony before the Public Utilities Commission of Ohio, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2011 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 12-1544-EL-UNC, May 2012.

Deposition testimony in *Tahoe City Public Utility District, Plaintiff vs. Case No. SCV 27283 Tahoe Park Water Company, Lake Forest Water Company, Defendants*, May 2012.

Deposition testimony in *Primex Farms, LLC, Plaintiff, v. Roll International Corporation, Westside Mutual Water Company, LLC, Paramount Farming Company, LLC, Defendants*, April 2012.

Direct and rebuttal testimony before the Michigan Public Service Commission, Case No. U-16999, on behalf of Michigan Consolidated Gas Company, regarding cost of service for natural gas distribution assets, April 2012 and October 2012.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. PA10-13-000, on behalf of ITC Holdings Corp. regarding a rehearing for FERC Staff, Office of Enforcement, Division of Audits, Report on the appropriate accounting for goodwill for the acquisition of ITC Midwest assets from Interstate Power and Light Company, February 2012.

Rebuttal testimony before the Florida Public Service Commission, Docket No. 110138-EL, on behalf of Gulf Power, a Southern Company, on the method to adjust the return on equity for differences in financial risk, November 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER12-296-000, on behalf of Public Service Electric and Gas Company on the Cost of Capital and for Incentive Rate Treatment for the Northeast Grid Reliability Transmission Project, October 2011.

Rebuttal Evidence before the National Energy Board in the matter of AltaGas Utilities Inc., 2010-2012 GRA Phase I, Application No. 1606694; Proceeding I.D. 904, October, 2011.

Report before the Arbitrator on behalf of Canadian National Railway Company in the matter of a Submission by Tolko Marketing and Sales LTD for Final Offer Arbitration of the Freight Rates and Conditions Associated with Respect to the Movement of Lumber by Canadian National Railway Company from High Level, Alberta to Various Destinations in the Vancouver, British Columbia Area, October, 2011.

Written direct and reply evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. NB7, as amended, and the Regulations made thereunder; and

in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part I and Part IV of the *National Energy Board Act*, for determining the overall fair return on capital in the business and services restructuring and Mainline 2012 – 2013 toll application, RH-003-2011, September 2011 and May 2012.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. PA10-13-000, on behalf of ITC Holdings Corp. in response to FERC Staff, Office of Enforcement, Division of Audits, Draft Report on the appropriate accounting for goodwill for the acquisition of ITC Midwest assets from Interstate Power and Light Company, July 2011.

Initial testimony before the Public Utilities Commission of Ohio, Case No. 11-4553-EL-UNC, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2010 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, July 2011.
Rebuttal testimony before the Public Utilities Commission of the State of California, Docket No. A.10-09-018, on behalf of California American Water Company, on Application of California American Water Company (U210W) for Authorization to Implement the Carmel River Reroute and San Clemente Dam Removal Project and to Recover the Costs Associated with the Project in Rates, June 2011.

Direct and rebuttal testimony before the Public Utilities Commission of the State of California, Docket No. A.11-05-001, on behalf of California Water Service Company, on the Cost of Capital for Water Distribution Assets, April 2011 and September 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER11-013-000, on behalf of the Atlantic Wind Connection Companies, on the Cost of Capital and Cost of Capital incentive adders for Electric Transmission Assets, December 2010.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. RP11-1566-000, on behalf Tennessee Gas Pipeline Company, on the Cost of Capital for Natural Gas Transmission Assets, November 2010.

Direct and rebuttal testimony before the Michigan Public Service Commission, In the matter of the application of The Detroit Edison Company, for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority, Case No. U-16472, October 2010 and April 2011.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission, Docket No. RP10-1398-000, on behalf of El Paso Natural Gas Company, on the Cost of Capital for Natural Gas Transmission Assets, September 2010 and September 2011.

Direct testimony before the Public Utilities Commission of Ohio, Case No. 10-1265-EL-UNC, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2009

Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, September 2010.

Direct testimony before the Michigan Public Service Commission, Case No. U-16400, on behalf of Michigan Consolidated Gas Company, regarding cost of service for natural gas distribution assets, July 15, 2010.

Direct testimony before the Oklahoma Corporation Commission, Cause No. PUD 201000050, on behalf of Public Service Company of Oklahoma, regarding cost of service for a regulated electric utility, June 2010.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER10-516-000, on behalf of South Caroline Gas and Electric Company, on the Cost of Capital for Electric Transmission Assets, December 2009.

Direct and Rebuttal Testimony before the California Public Utilities Commission regarding cost of service for San Joaquin Valley crude oil pipeline on behalf of Chevron Products Company, Docket Nos. A.08-09-024, C.08-03-021, C.09-02-007 and C.09-03-027, December 2009 and April 2010.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER10-159-000, on behalf of Public Service Electric and Gas Company, on the incentive Cost of Capital for the Branchburg-Roseland-Hudson 500 kV Line electric transmission project ("BRH Project"), October 2009.

Rebuttal testimony before the Florida Public Service Commission in re: Petition for Increase in Rates by Progress Energy Florida, Inc., Docket No. 090079-EI, August 2009.

Direct and rebuttal testimony before the State of New Jersey Board of Public Utilities in the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 14 Electric and B.P.U.N.J No. 14 Gas Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Approval of a Gas Weather Normalization Clause; a Pension Expense Tracker and for other Appropriate Relief BPU Docket No. GR09050422, June 2009 and December 2009.

Direct and rebuttal testimony before the Public Service Commission of Wisconsin, Docket No. 6680-UR-117, on behalf of Wisconsin Power and Light Company, on the cost of capital for electric and natural gas distribution assets, May 2009 and September 2009.

Written evidence before the Régie de l'Énergie on behalf of Gaz Métro Limited Partnership, Cause Tarifaire 2010, R-3690-2009, on the Cost of Capital for natural gas transmission assets, May 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-681-000, on behalf of Green Power Express, LLP, on the Cost of Capital for Electric Transmission Assets, February 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-548-000, on behalf of ITC Great Plains, LLC, on the Cost of Capital for Electric Transmission Assets, January 2009.

Written and Reply Evidence before the Alberta Utilities Commission in the matter of the Alberta Utilities Commission Act, S.A. 2007, c. A-37.2, as amended, and the regulations made thereunder; and IN THE MATTER OF the Gas Utilities Act, R.S.A. 2000, c. G-5, as amended, and the regulations made thereunder; and IN THE MATTER OF the Public Utilities Act, R.S.A. 2000, c. P-45, as amended, and the regulations made thereunder; and IN THE MATTER OF Alberta Utilities Commission 2009 Generic Cost of Capital Hearing, Application No. 1578571/Proceeding No. 85. 2009 Generic Cost of Capital Proceeding on behalf of AltaGas Utilities Inc., November 2008 and May 2009.

Written Evidence before the Alberta Utilities Commission in the matter of the Alberta Utilities Commission Act, S.A. 2007, c. A-37.2, as amended, and the regulations made thereunder; and IN THE MATTER OF the Gas Utilities Act, R.S.A. 2000, c. G-5, as amended, and the regulations made thereunder; and IN THE MATTER OF the Public Utilities Act, R.S.A. 2000, c. P-45, as amended, and the regulations made thereunder; and IN THE MATTER OF Alberta Utilities Commission 2009 Generic Cost of Capital Hearing, Application No. 1578571/Proceeding No. 85. 2009 Generic Cost of Capital Proceeding on behalf of NGTL, November 2008.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, Case No. 08-1783-G-PC, on behalf of Dominion Hope Gas Company concerning the Cost of Capital for Gas Local Distribution Company assets, November 2008 and May 2009.

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Schedule MJV-2
Imputed Debt Methodology

EDISON ELECTRIC INSTITUTE

WHITE PAPER

UNDERSTANDING DEBT IMPUTATION ISSUES

BY

THE BRATTLE GROUP

FOR

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EXECUTIVE SUMMARY

This white paper explores the issue of **debt imputation**. It is written for EEI members and regulatory staff, to understand the issue, and review options for addressing it in the rate making process.

Section I, *Introduction*, defines "imputed debt" as a measure of the financial risk shifted to a utility when it enters into a purchased power agreement ("PPA"). Use of PPAs can undermine the utility's credit worthiness, if no financial adjustment is made to its capital structure.

Section II, *Wholesale Market Developments Increase the Importance of Imputed Debt*, explains that the use of PPAs was spurred by PURPA and the Energy Policy Act of 1992. With a few exceptions, the original concept of a fully competitive wholesale market (i.e., in which all generation is owned by independent power producers - IPP), has given way to a hybrid wholesale market in which generation is owned both by regulated utilities and IPPs.

Section III, *How is Imputed Debt Calculated?*, reviews Standard & Poor's (S&P) updated methodology for calculating the debt equivalence of PPAs and imputing it onto a utility's balance sheet and income statement for the purpose of assessing credit worthiness. The debt equivalence value is calculated as the present value of the fixed (capacity) portion of annual payment, discounted at the utility's average cost of debt, and multiplied by a risk factor. The risk factor is intended to reflect the probability that PPA costs will be fully recovered in rates and varies depending on state-specific legislative and/or regulatory policy. Greater certainty of recovery is reflected in a lower risk factor which results in a smaller amount of equivalent debt per contract. Imputed interest expense, calculated as the equivalent debt times the embedded debt cost, is added to the utility's interest expense. An annual amount of depreciation is also estimated as the difference between the capacity payment and the imputed interest for the year. Imputed debt, imputed interest expense and imputed depreciation affect the three key ratios S&P uses to assess credit worthiness (i.e., debt/total capital, funds from operations ("FFO")/average total debt, and FFO/interest expense).

Section IV, *Is Debt Equivalence a Real Problem?,* demonstrates that imputed debt is a problem

whose potential severity should be of concern to regulatory authorities. Like debt, PPAs increase the utility's financial risk by obligating future cash flow. Fixed payment obligations, like interest payments and the payments for a PPA, reduce financial flexibility and increase the probability that the utility will default on its obligations. For proof that PPAs transfer risk to utilities, we need only examine the reciprocal effect that PPAs have on the suppliers (the counterparties to PPAs). According to S&P, PPAs reduce supplier risk. This can only be true if supplier risk is being transferred to the utility and its customers via the terms of the PPA. For policy makers, debt equivalence should be of concern because it can affect credit ratings by either impeding upgrades and/or triggering down grades. Weaker credit ratings, in turn, can increase borrowing costs and/or restrict borrowing capacity, both of which harm rate payers.

Section V, *How Big A Problem is Imputed Debt?*, shows that for utilities whose credit ratings are marginally investment-grade, imputed debt can be a big problem. For such utilities, imputation of PPA-related debt equivalence could push their credit below investment-grade status. For the seven electric utilities whose data S&P publishes, average debt to equity was 58% before imputation and 63% after. Even for utilities with a business risk profile of "Excellent" or "Strong", a 58% ratio corresponds to an "aggressive" financial risk indicator and a low BBB- to high BBB credit rating, while a 63% ratio corresponds to a "highly leveraged" financial risk indicator and a BB- to BB rating.

Section VI, *Mitigation of the Impact of Imputed Debt*, describes three options for addressing debt imputation. These are summarized in Table ES-1.

Table ES-1: Options for Addressing Imputed Debt	
Method	**Considerations**
1. INCREASED EQUITY - Increase equity, decrease debt to restore pre-PPA capital structure	• Mitigates PPA financial risk • Does not completely restore FFO/interest, FFO/debt ratios • Expensive to use for each PPA • Incurs cost to issue new equity
2. INCREASED ROE - Increase allowed ROE so that pre-PPA ATWACC = post-PPA ATWACC	• Compensates shareholders for increased risk • Does not fully restore any ratios • Not sufficient for utilities with low credit ratings
3. RATIO RESTORATION - Impute new equity sufficient to restore selected ratio to pre-PPA level, collect this via an adder to the PPA payment	• Compensates shareholders for increased risk • Mitigates financial risk • Can be applied for each PPA • Helps utilities with low credit better than methods # 1 and 2 • More expensive than methods # 1 and 2 • Requires choice of which ratio to restore

Section VII, *Conclusions*, suggests five overall conclusions for policy makers, as follows: (1) Long-term PPAs transfer financial risk from the seller to the buyer; (2) Policy makers should be particularly sensitive to PPA-related risk transfer in situations where the utility's credit rating is minimally investment-grade; (3) Regulatory policies which provide assurance of PPA cost recovery can effectively mitigate the impact of imputed debt on the credit rating of purchasing utilities; (4) There is no perfect solution to the problem of PPA-related risk transfer and imputed debt; and (5) In competitive procurement situations, it is important that imputed debt be addressed in a competitively-neutral way.

Appendix A, *Treatment of Imputed Debt in Certain States*, surveys recent precedent involving PPAs and imputed debt. Recent state decisions are summarized in Table A.

Table A: Recent State Precedent		
CA	Has retreated from an earlier policy that allowed IPP bids to be adjusted to account for risk transfer. Now only considers debt equivalence after-the-fact in the utilities' costs of capital.	*Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's Long-Term Procurement Plans*, Decision 07-12-052, December 20, 2007.
DE	Allowed Delmarva to assign a cost adder to bid prices based on imputed equity equal to 30% of the NPV of capacity payments, and a portion of the energy payment if the Company concludes that energy payments will be imputed as debt by rating agencies.	Order No. 7081, 11/21/06
FL	Allowed FPL to increase its equity thickness to offset PPA-related imputed debt. Also requires utilities to include the cost of incremental equity in comparing PPAs to other resource options.	*Order Approving Stipulation and Settlement*, Docket No. 990067-EI, Order No. PSC-99-0519-AS-EI, 3/17/99. See also 70 F.A.C. Rule 25-22.081, paragraph 7.71 Order No. PSC-99-1713-TRF-EG, Docket No. 990249-ET, 9/2/99. (??)
NV	Promulgated rules that allow PPA adders tied to the cost of offsetting equity. To date, no adders have been approved.	NRS 704.7821(7) (b), issued pursuant to Assembly Bill No. 3, passed June 2005.
NM	Denied a PPA adder tied to the cost of offsetting equity. Apparently, the commission found insufficient evidence that the utility's credit rating would fall below investment-grade as the result of imputation.	*Final Order on Exceptions*, Case No. 06-00340-UT, 12/18/06
WI	Allowed WI Public Service Corp. to add new equity to offset imputed debt from long term PPAs and operating leases.	*Final Decision*, 6690-UR-118, January 15, 2008.

I. INTRODUCTION

With the growth and importance of competitive wholesale markets, many regulated electric utilities enter into long-term purchased power agreements ("PPAs") to meet the power supply needs of their customers in a least cost and reliable manner.[1] Regulated utilities have traditionally passed (or attempted to pass) all purchased power costs through to ratepayers on a dollar-for-dollar basis without any extra compensation accruing to the utility. However, full recovery is contingent on approval by the utility's regulatory body, including any regulatory lag.[2] The financial community and the rating agencies recognize that there are different regulatory risks involved in the different state regulatory approaches to the recovery of purchased power (and fuel) costs.[3] This means that signing a long-term PPA increases the financial risk of the purchasing utility commensurate with the size and length of the fixed-cost obligations in the contract. The amount of financial risk also depends on the likelihood of full recovery of the costs of the contract, which in turn depends on the supportiveness of the regulatory and legislative climate.

The financial risk inherent in signing a long-term PPA is measured by the credit rating agencies

[1] The authors are aware of the current controversies about the functioning of the U.S. wholesale power markets but believe that the issues discussed here will continue to be important in whichever direction state and national competitive policy moves.

[2] In this context, regulatory lag refers to the delay between the time costs are incurred and the time those costs are recovered in rates. If there is a substantial delay in recovery, the utility would not be fully compensated for the cost of the PPAs unless the PPA balances receive a carrying cost. In other words, the utility would lose the time value of money.

[3] For example, S&P's, "Fuel and Purchased Power Cost Recovery in the Wake of Volatile Gas and Power Markets – U.S. Electric Utilities to Watch", Report, March 22, 2006 and , S&P's, "Request For Comments: Imputing Debt To Purchased Power Obligations," November 1, 2006 and Fitch Ratings, *Are Power Contracts Debt Equivalents?,* July 2006.

and is known as "imputed debt" or "debt equivalence".[4] (This paper will use the term "imputed debt" for ease of exposition). One credit rating agency, Standard & Poor's (S&P), has clearly stated its view for many years that long-term PPAs impose financial risk on the utility and has developed and publicized a standard procedure for calculating imputed debt and its impact on the financial ratios used to measure a utility's creditworthiness.[5] If nothing were done, the imputed debt resulting from a large portfolio of PPAs may lead to a credit rating downgrade. In addition, the weakened credit ratings (i.e., increased financial risk) would increase the purchaser's cost of equity and debt capital assessed by financial markets.

In light of the continuing importance of long-term PPAs, this paper reviews and illustrates the financial risk of concern to the credit rating agencies. In particular, the paper addresses the issue of whether the financial risk from long-term PPAs is a real concern, and if so, how big a problem it is likely to be. If the problem is real and large enough to be of concern, what can regulators do to mitigate its effects? Below, the paper discusses several alternative ways to mitigate the adverse effects of imputed debt on the purchasing utility. The goal of any mitigation effort should be to treat shareholders and rate payers fairly, but mitigation will also benefit ratepayers and shareholders by neutralizing the negative effects from PPAs, including the weakening of the company's credit metrics and the increased cost of capital.

[4] Credit rating agencies have generally treated long-term PPA contracts differently from short-term power contracts. In the past, credit rating agencies did not believe that short-term contracts (in particular those signed in retail access states for Provider of Last Resort ("POLR") service, which are generally three-month to three-year contracts and are rebid periodically to keep prices closer to the spot market), carried the same negative financial impact as a long-term PPAs. However, S&P recently announced that it is will impute debt from most such "evergreen" contracts going forward. See, *Imputed Debt Calculation for U.S. Utilities' Power Purchase Agreements*, S&P RatingsDirect, March 30, 2007. S&P excludes PPAs in which the utility merely acts as a conduit for delivery of power. See *Standard & Poor's Encyclopedia Of Analytical Adjustments for Corporate Entities*, July 9, 2007 p. 39.

[5] Periodically S&P has revised its procedures for calculating imputed debt. This paper reflects S&P's current policy.

The rest of this paper is organized as follows: *Section II* briefly describes the development of the wholesale generation market and the coming generation "build out". *Section III* describes the credit rating agencies' views and illustrates the calculation of imputed debt based upon the method published by S&P and its effect on a utility's credit ratios. *Section IV* addresses the issue of whether imputed debt is a problem that should be of concern to regulators, and *Section V* illustrates how large the problem could be given the increase in PPA type contracts. *Section VI* describes the approaches that a regulatory agency might adopt to mitigate the effects of imputed debt on the financial ratios of a utility should it chose to do so, and *Section VII* provides concluding remarks. *Appendix A* contains a discussion of the current treatment of imputed debt in the states of California, Delaware, Florida, Nevada, New Mexico and Wisconsin. The appendix reports how these states have chosen to deal with the issue at this time.

II. WHOLESALE MARKET DEVELOPMENTS INCREASE THE IMPORTANCE OF IMPUTED DEBT

Long-term wholesale PPAs have been a source of supply for regulated utilities for many years, but before the 1980's, most utilities met their obligation to serve through their own generation resources. Growth in long-term PPAs was spurred by PURPA[6] policies in the 1980s and became wide reaching after the Energy Policy Act of 1992 began the process of providing open access to the FERC-regulated transmission grid. Exempt wholesale generator ("EWG") is a category of generators that is permitted to sell electricity only in the wholesale market.[7] Long-term contracting for supply from EWGs by regulated utilities became a standard part of wholesale power markets. In the early 1990s, S&P as well as some financial analysts recognized that there

[6] The Public Utility Regulatory Policies Act of 1978

[7] See U.S. Code, Title 42, Chapter 149, Subchapter XII, Part D, Section 16451 (6).

is a risk transfer from the seller to the buyer inherent in long-term PPAs resulting from PURPA and the growth of the role of EWGs in the wholesale power market.[8] Over the last twenty years, independent power producers ("IPPs") have become major builders of power plants, owners of existing generation resources, and potential low-cost developers of new resources. Many states now require that a utility proposing to build its own plant demonstrate that the proposed plant is in the ratepayers' interest by being lower in expected future revenue requirements than competitive bids for comparable supply from IPPs.

The original 1990's concept of a fully competitive wholesale power market envisioned that eventually all electric generation plants (outside the public power sector) would be owned by IPPs (some of whom would possibly be affiliated with regulated distribution utilities), selling under long-term contracts, short-term contracts, or in the spot market.[9] A corollary of that vision was that all new electric generation assets would be built with private investment in the form of independent merchant plants or plants with contracts from retail marketers or large customers. There would be little or no role for plants built under cost-of-service regulation.

In fact, the history of the development of a competitive wholesale market has not been smooth and includes the California energy crisis (with eight FERC Settlements and $3-5 billion in

[8] S&P first published its criteria for evaluating long-term PPAs in 1990, updated them in 1993, and most recently in early 2007. See " 'Buy Versus Build': Debt Aspects of Purchased-Power Agreements," *Utilities & Perspectives*, May 12, 2003, p. 2. See also "Imputed Debt Calculation for U.S. Utilities' Power Purchase Agreements," *S&P RatingsDirect*, March 30, 2007, "Purchased Power - Hidden Cost or Benefits?", *The Electricity Journal*, September 1994, pp. 74-83, by A. L. Kolbe, S. Johnson, J.P. Pfeifenberger and D. M. Weinstein, and "A Simplified Procedure for Costing the Financial Risks of Purchased Power Contracts," *The Electricity Journal*, April 1997, pp. 70-75 by William B. Tye and Marvin A. Hawthorne.

[9] "Keeping up with retail access? Developments in U.S. Restructuring and Resource Procurement for Regulated Retail Service," *The Energy Journal*, December 2004, by J. Pfeifenberger, A. Schumacher and J. Wharton. The authors note that states in the U.S. can be divided into three groups: the retail access states share this vision, the traditional regulation states do not share this vision, and the transition states which started toward retail competition and stopped (e.g., California) or did partial retail access for only large customers (Nevada and Oregon). The third group and possibly the second procure long-term resources for their portfolios using PPAs or both PPAs and utility-owned generation plants.

refunds) and the heightened concerns about market power abuse and the need for its mitigation. Moreover, there has not been the full development of a competitive retail market for all customers in most retail access states during the transition periods. Texas and some other states continue to pursue the original vision of wholesale competition, generation investment by independent producers, and price rationing of scarce supplies should a shortage come to pass. However, policy makers in many states have questioned the efficacy of actual, or potential, shortage premiums in spot prices as effective and reasonable long-range signals for new generation investment and resource adequacy. The majority of states never adopted retail access and some of those that did are reviewing the policy in light of recent developments.[10]

Fitch Ratings ("Fitch") has come to be skeptical about the amount of new generation that will be built by IPPs without long-term contracts with regulated utilities. In a 2005 report, Fitch concluded that:[11]

> . . . states are unlikely to test the fourth alternative of competitive [wholesale] markets, allowing the competitive market to work and waiting to see the result. . . . Evidently the public is unwilling to accept the volatility associated with a purely competitive wholesale market. It would appear that competition is politically acceptable when it lowers prices, but not when it raises them. [Emphasis added]

A "hybrid wholesale market" model has now emerged where, over the long term, policy makers will encourage a balance of new generation plants that are owned and operated (and sometimes built) by regulated utilities and those that are owned and operated by IPPs with or without long-term contracts. California is prominent in pursuing the hybrid market structure.[12] Long-term contracts will continue to play a major role in the hybrid wholesale markets, so imputed debt will

[10] See discussion of Delaware in the Appendix for a development in the direction.

[11] Fitch Ratings, "Stimulating Generation Additions in Deregulated States," *Corporate Finance*, Nov. 4, 2005.

[12] See CPUC Decision 06-07-029, *Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation*, July 20, 2006.

remain as an important issue in assessing a utility's financial strength.[13]

III. HOW IS IMPUTED DEBT CALCULATED?

Imputed debt, or debt equivalence, is a term used by credit rating agencies and financial analysts to describe and quantify the financial risk inherent in the fixed financial obligation resulting from signing long-term contracts, such as PPAs or operating leases. Under current FASB standards, these obligations are not reported on the company's balance sheet although the accompanying notes do disclose these arrangements.[14] However, these contracts have debt-like characteristics because they commit the utility to pay periodically a fixed amount to an outside party. Because these obligations have features similar to debt, they are treated as such to some degree by the credit rating agencies. S&P has developed and publicized a standard procedure for calculating the amount of imputed debt resulting from signing a long-term PPA contract and for determining its impact on a utility's creditworthiness. Other credit rating agencies, such as Moody's or Fitch Ratings, have been less forthcoming in how they evaluate the effect of a long-term PPA on a utility's credit rating. Consequently, this paper relies primarily on S&P's published materials to illustrate the calculation of imputed debt and its impact on a utility's financial ratios.[15]

Another way to view the risk characteristics of imputed debt is to recognize that building and operating an electric generating plant entails substantial risk. This is true whether the plant is built by a utility or by an IPP. Frequently, the only way an IPP developer can secure financing to

[13] As is reflected in Appendix A, utilities' dependence on long-term PPA's is also increasing because of the impact of renewable resource portfolio standards.

[14] Recent financial accounting standards appear to be moving in the direction of greater scrutiny of PPA contracts that has the potential for some contracts to be classified as capital leases which would require them to be reported on the utility's balance sheet.

[15] Below, the other two credit rating agencies, Moody's and Fitch, are briefly discussed in comparison on some points.

construct a power plant is by first contracting with a credit-worthy regulated utility. The fixed, contractual PPA payments serve as the basis for the developer to obtain financing at reasonable rates. If a utility builds a plant, the debt and equity used to finance construction of the plant would appear on the regulatory books of the utility, but not if the same financial commitment is made through a PPA. The concept of imputed debt simply recognizes that there is a risk transfer from the developer to the regulated utility inherent in the commitment to make the PPA payments and attempts to recognize the underlying economics of the transaction. Without recognition of the increased financial risk from the PPA, signing a PPA would have the illogical result of seeming to make the risk of investing in electric generating plants disappear. Moreover, all else equal, electric power plants proposed by IPPs might be incorrectly chosen as least expensive in a head-to-head competition with a regulated utility if the risk transfer were not recognized.[16] Thus, the calculation of imputed debt recognizes that the mechanism of a PPA does not eliminate risk, but merely transfers the risk to the utility and its ratepayers. The division of the risk transfer between the utility and its ratepayers depends upon the regulatory mechanisms in place for recovery of the costs of the PPA as measured by S&P using its so-called "risk factor" which is described below.

A. STANDARD & POOR'S IMPUTED DEBT METHODOLOGY

In the electric industry, S&P imputes debt for PPAs, operating leases, and the unfunded portion of post-retirement obligations. S&P is specific about its calculations. To understand how

[16] There is not universal agreement on this point. For example, The Electric Power Supply Association ("EPSA") believes that acknowledging the risk of imputed debt risks tilting the competition between IPPs and regulated utilities in favor of utilities if construction risk and other risks accepted by IPPs are not recognized. See for example, "Impacts of Credit Requirements, Cost of Capital and Debt Equivalency Issues on Power Supply Acquisition (Remarks by EPSA President and CEO John E. Shelk at the *Western Power Supply Forum* - May 9, 2006). The authors believe that an accurate judgment in the build-versus-buy decision requires consideration of *all* of the risks including construction risk and imputed debt.

imputed debt is assessed, it is helpful to review S&P's explicit approach as it has been defined in publications over the years. The calculation of imputed debt for PPAs parallels the treatment of operating leases, which is discussed first.

For operating leases,[17] S&P calculates the present value of future minimum lease payments using the utility's average embedded interest rate. The resulting amount is added to the utility's reported long-term debt for purposes of calculating the utility's financial ratios.[18] In addition, an implicit (or imputed) interest expense is calculated as the average net present value of the contract payments multiplied times the utility's average interest rate. This implicit interest is added to the reported interest expense for the purpose of calculating ratios. An imputed depreciation amount is also determined as the average of the year-one minimum lease payment in the current and previous year minus the implicit interest expense.[19] This amount is added to the reported depreciation expense.[20]

Fitch Ratings also calculates adjusted ratios for operating leases and uses one of two methods to value off-balance sheet lease obligations.[21] One method relies on a multiple of the minimum annual lease obligation (typically 8 *times* the annual obligation). A second method calculates the

[17] Under current accounting standards, capital leases are recognized on a company's balance sheet while operating leases are not. A lease is classified as a capital lease if it satisfies one of four criteria: (1) ownership of the asset is transferred to the lessee, (2) the lease contains a bargain purchase option - - i.e., the lessee can purchase the asset at below fair market value, (3) the lease term is equal to 75% or more of the asset's economic life, or (4) the present value of the minimum lease payments equals or exceeds 90% of the fair value of the leased property. Leases that do not meet any of these criteria are operating leases.

[18] This amount is also added to assets, to reflect the implicit value the utility has from using the asset, when calculating ratios that involve assets.

[19] To ensure that expenses properly reflect the imputed debt amount rather than the reported amount, the average of the current and previous year's minimum lease payment minus the implicit interest expense is added to the reported expenses. This is simply to avoid double-counting of any amount.

[20] Moody's Investor Service appears to be using a similar approach. S&P's and Moody's use analytical models to convert leases using present value of minimum lease payments. Moody's capitalizes full notional value of 'essential' or 'core' assets, 1st Annual ELA/SEC Meeting, September 8, 2005.

[21] Fitch Ratings, *Corporate Finance*, "Operating Leases: Updated Implications for Lessees' Credit", December 20, 2006.

present value ("PV") of non-cancellable future lease obligations. When enough information is available to calculate both estimates of the lease obligations, Fitch Ratings takes both into account and uses the adjusted figures in calculating leverage and coverage ratios, using the adjusted debt amount and including the total lease expense in the interest expense.[22] Fitch states that the adjustment is significant for about half the entities they follow. This paper focuses on imputed debt arising from PPAs; therefore, the treatment of operating leases and unfunded pension liabilities is not discussed further.

S&P's method for calculating imputed debt begins by determining the PV of the fixed payment (capacity) portion of the PPAs, using the utility's average embedded cost of debt as the discount rate. "If capacity payments are not specified, S&P will use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied times the number of kilowatts under contract."[23]

S&P next determines a so-called "risk-factor" which is a company-specific measure of the likelihood of full recovery of the costs of the PPA. S&P determines the risk factor based upon characteristics of the company and its regulatory environment. Risk factors vary between 0 and 100 percent, but they are typically in the range of 25 to 50 percent. For rate-regulated utilities, the risk factor depends primarily on the regulatory environment and especially on the mechanism used to recover capacity costs. As a benchmark, S&P states the risk factor "will generally be 25% for capacity payments that are recovered through fuel adjustment clauses and 50% for

[22] Fitch Ratings discusses a third method which is primarily applied to entities in bankruptcy or reorganization. In this case Fitch Ratings looks at the liquidation value.

[23] See "Standard & Poor's Methodology for Imputing Debt for U.S. Utilities' Power Purchase Agreements," S&P *Commentary Report*, May 7, 2007, p. 5.

capacity payments that are recovered in base rates."[24,25] Unregulated energy companies that enter into a tolling arrangement are generally assigned a risk factor of 100%.[26] The risk factor multiplied by the PV of the fixed capacity payments equals the amount of imputed debt that is added to the utility's reported long-term debt for the purpose of calculating financial ratios.

Imputed interest expense is calculated by multiplying the calculated amount of imputed debt by an interest rate. S&P changed its methodology to use the utility's average embedded cost of debt as the discount rate instead of a standard 10 percent.[27] The imputed interest expense is added to the utility's interest expense for the purpose of computing ratios. Finally, S&P determines imputed depreciation as the risk factor times the capacity payment minus the imputed interest expense. Example 1 below illustrates the process.

Example 1:
Assume that Utility ABC enters into a 20-year PPA that has annual capacity payments of $39.2 million. Utility ABC has embedded cost of debt of 6.7%. Finally assume that Utility ABC has been assigned a risk factor of 25% from S&P.

Using a discount factor of 6.7%, the PV of the 20-annuity would be about $425 million. In the first year, S&P imputes debt of about $106 million ($425 million x 25%) and an interest expense of approximately $7 million ($106 million x 6.7%). Finally, S&P imputed depreciation would be about $2.7 million ($39.2 x 25% -$7 million of interest expense) in the first year.

[24] "Request for Comments: Imputing Debt to Purchased Power Obligations," Standard & Poor's, November 1, 2006.

[25] S&P believes that vertically integrated, regulated electric utilities with a fuel adjustment clause have moderate risk and recently adjusted the risk factor for such utilities downward to 25% (from 30%). In jurisdictions with true-up mechanism but no pure fuel adjustment clause, vertically integrated electric utilities generally are assigned a risk factor between 25% and 50%. In jurisdictions where recovery of PPA-related capacity costs is guaranteed by a legislative mechanism, the timeliness of the mechanism affects the risk actor which may be as low as 0%. See "Request for Comments: Imputing Debt to Purchased Power Obligations," Standard & Poor's, November 1, 2006. Merchant generators are assigned a higher risk factor than vertically integrated regulated utilities, and tolling contracts are assigned a risk factor of 100%. See "Imputed Debt Calculations for U.S. Utilities' Power Purchase Agreements," Standard & Poor's, March 30, 2007.

[26] See, *Standard & Poor's Encyclopedia of Analytical Adjustments for Corporate Entities*, July 9, 2007.

[27] See, "Imputed Debt Calculations for U.S. Utilities' Power Purchase Agreements," Standard & Poor's, March 30, 2007.

B. FINANCIAL RATIOS CONSIDERED BY S&P

The calculation of imputed debt and imputed interest expense results in an *adjusted balance sheet* and an *adjusted income statement* that are then used to calculate the utility's financial ratios. Currently, S&P relies primarily on three ratios plus qualitative factors to evaluate a utility's credit worthiness or default risk. The three key ratios[28] are

(1) FFO interest coverage = FFO / (interest expense).

(2) Funds from Operations (FFO) to average total debt,[29] and

(3) Debt to total capital.

In the past, S&P also considered the Earnings before Interest and Taxes (EBIT) interest coverage ratio, but this ratio has been de-emphasized.

While other credit rating agencies have been less forthcoming about their methodology, all have publications that indicate that they take debt equivalence seriously. For example, "policy dictates that operating leases be capitalized"[30], and Moody's explicitly includes "operating lease adjustment," "under-funded pension liabilities" and "other debt-like items" in their adjusted debt amount.[31] Both Moody's and Fitch discuss the impact of PPAs in their publications regarding electric utilities although both seem to generally be less concerned about the impact of PPAs than S&P.[32] Both Moody's and Fitch's consider the regulatory treatment a key element in evaluating PPAs. In addition, it is noteworthy that utilities generally have comparable ratings

[28] A detailed description of each ratio can be found in S&P's *Corporate Ratings Criteria 2007.2008.*

[29] Average total debt is usually calculated as the average debt over the past 12 months.

[30] Fitch Global Power Methodology and Criteria: *Debt-like obligations and contracts other than funded debt*, April 2004.

[31] Moody's Investor Service, *Ratings Methodology: Global Regulated Electric Utilities*, March 2005.

[32] See, for example, Moody's Investor Service, *Ratings Methodology: Global Regulated Electric Utilities*, March 2005, and Fitch Ratings, *Are Power Contracts Debt Equivalents?*, July 2006. *U.S. Utility Financial Peer Studies: Investor-Owned & Public Power Utilities*, June 2005. Standard & Poor's, *Fuel And*

from the different rating agencies, and utilities frequently furnish the same non-public information regarding their PPAs to all credit rating agencies.

IV. IS DEBT EQUIVALENCE A REAL PROBLEM?

A key concept in finance is that financial risk increases with leverage (i.e., the use of debt), and as a company increases its financial leverage, its cost of equity also increases. Therefore, a company's financial risk depends on the manner in which the company finances its operations. The more debt the company has in its capital structure, the greater its financial risk. If a utility builds a power plant, an asset appears on its balance sheet along with the associated sources of financings, either equity, debt, or both. If a utility enters into a capital lease, an asset and an offsetting long-term liability appear on its balance sheet. Similarly, if a utility enters into a long-term operating lease or PPA, it has made a commitment to make fixed payments as if it had incurred a debt obligation, but no debt appears on its balance sheet.[33] The addition of a PPA (or portfolio of PPAs) and the associated fixed payments create a debt-like obligation and increases the utility's financial risk just as would the addition of debt to the utility's capital structure. The PPA payments decrease the utility's financial flexibility and increase the variability of the return on the utility's equity. S&P merely recognizes the underlying economics of the situation by adding a "debt equivalent" amount when it assesses the utility's financial strength.

Additional evidence of an increase in financial risk by the buyer of PPAs is the reduction of risk for the seller. Electric generating plants built by IPPs without long-term PPAs are considered to

Purchased Power Cost Recovery In The Wake of Volatile Gas And Power Markets - - U.S. Electric Utilities To Watch, March 22, 2006,

[33] The asset from the regulator's promise to allow the recovery of the PPA costs does not appear on the balance sheet either, but the PPA payments represent a contractual obligation the utility cannot avoid while recovery of the PPA costs is uncertain. It is precisely the contrast between the commitment to make the PPA payments and the uncertainty of full cost recovery that is creating the increased financial risk.

be of high risk (as discussed by Fitch, reported in Section II above). Signing a long-term contract with a credit-worthy utility considerably lowers the risk premium the plant's investors would have to pay to finance the project. In fact, having a long-term contract in place is often the only way a potential power plant builder can finance the investment. Fitch recognizes this:[34]

> The traditional method for independent generators was to rely on the strength of a PPA with a creditworthy off-takers (usually a utility) to help finance the construction cost of a new power plant. Take or pay contracts or firm capacity payments under the PPA would allow the developer to raise debt financing for the project, either using single asset project financing or under a portfolio financing approach. In general, power developers of this type have lower credit rating than those of the power purchaser. These developers can raise financing on more favorable terms if they can take advantage of the credit enhancement that comes from contractual cash flows from credit worthy counterparties.

Clearly, if the PPA seller has less risk, the PPA buyer and its customers have more. Risk has been transferred to the utility and its customers. The distribution of the transferred risk between the utility and its customers depends upon the strength of the cost recovery mechanisms in place. The more uncertain is full recovery of the costs of the PPA, the more risk the utility bears.

Although the use of leverage through fixed-cost capital, operating leases, or PPAs can be advantageous and reduce costs, it also increases financial risk due to the fixed contractual obligations associated with the leverage. PPAs, like debt, create a fixed obligation that revenues must support before any earnings can be made available to common shareholders. The credit rating agencies (S&P, Moody's and Fitch) have noted that the commitment to pay for these contract costs increases the financial risk of the utilities involved. Although the rating agencies' specific concern is that the risk of default on the utility's debt could be adversely affected by the requirement to make payments on the PPAs, the increased financial risk affects the risk (and

[34] Fitch Rating, "Stimulating Generation Additions in Deregulated States," *Corporate Finance*, Nov. 4, 2005, p. 2.

required return) of the utility's equity capital as well. Investors' recognition of the presence of imputed debt affects the terms and costs under which the utility can raise debt and equity capital.[35] Therefore, it is essential that regulators also consider the presence of such obligations. Because S&P (and possibly the other rating agencies) determine the risk factor for a utility based in part on the regulatory treatment of purchased-power costs in the jurisdiction in which the utility operates, legislative and regulatory policy directly affect the magnitude of the imputed debt.[36] The additional leverage from PPAs influences the utility's cost of equity, the terms under which it can raise debt, and possibly the terms under which it can sign additional PPAs. At the margin, if a utility is not deemed creditworthy, it may not be able to raise debt or sign PPAs under reasonable terms.

In a recent publication, S&P illustrated how the regulatory environment and fuel/purchased power interact. Rating the regulatory recovery mechanism from "Historically Challenged" through "No or Weak Fuel Adjustment" to "Rate Freeze" and operating risk from Low to High, S&P indicated that entities with High Operating Risk in a "Rate Freeze" environment are at high risk for cash flow volatility and thus credit risk. The study identified six utilities as being at "considerable risk."[37]

The higher the level of purchased power and imputed debt, the greater the potential impact on adjusted utility financial ratios and ratings. The S&P adjustments to existing debt and the

[35] One indication that investors consider the presence of off-balance sheet obligations such as imputed debt to be important is that Generally Accepted Accounting Principles ("GAAP") currently require companies to disclose information about upcoming operating lease payments as well as the funding status of pension obligations.

[36] Fitch Ratings and Moody's also consider the likelihood of cost recovery. See, Fitch Ratings, *Global Power Methodology and Criteria: Debt-Like Obligations and Contracts Other Than Funded Debt*, April 2004 and Moody's, *Ratings Methodology: Global Regulated Utilities*, March 2005.

[37] Standard & Poor's Credit Ratings, *Fuel and Purchased Power Cost Recovery in the Wake of Volatile Gas and Power Markets- - U.S. Electric Utilities to Watch*, March 22, 2006.

resulting calculation of key ratios can have the following effects on a utility:

a. Consideration of the cost of imputed debt affects integrated resource planning in the buy-versus-build decisions.
b. For some utilities, it may impede credit rating upgrades or lead to debt rating downgrades that would, in turn, lead to
    1. Restricted borrowing capacity and/or higher costs of capital for utilities and customers;
    2. Restrictive prepayment terms with fuel and purchased power counterparties; and
    3. An overall decrease in market value as utility common equity share price and debt price may be ultimately impacted.

Because all of the above affect the utility's financing and operating decisions, it is important to recognize and to mitigate the potential adverse effects of imputed debt. In particular, the risk transfer from power generators to utilities through long-term PPAs must be acknowledged and taken into account in regulatory proceedings.

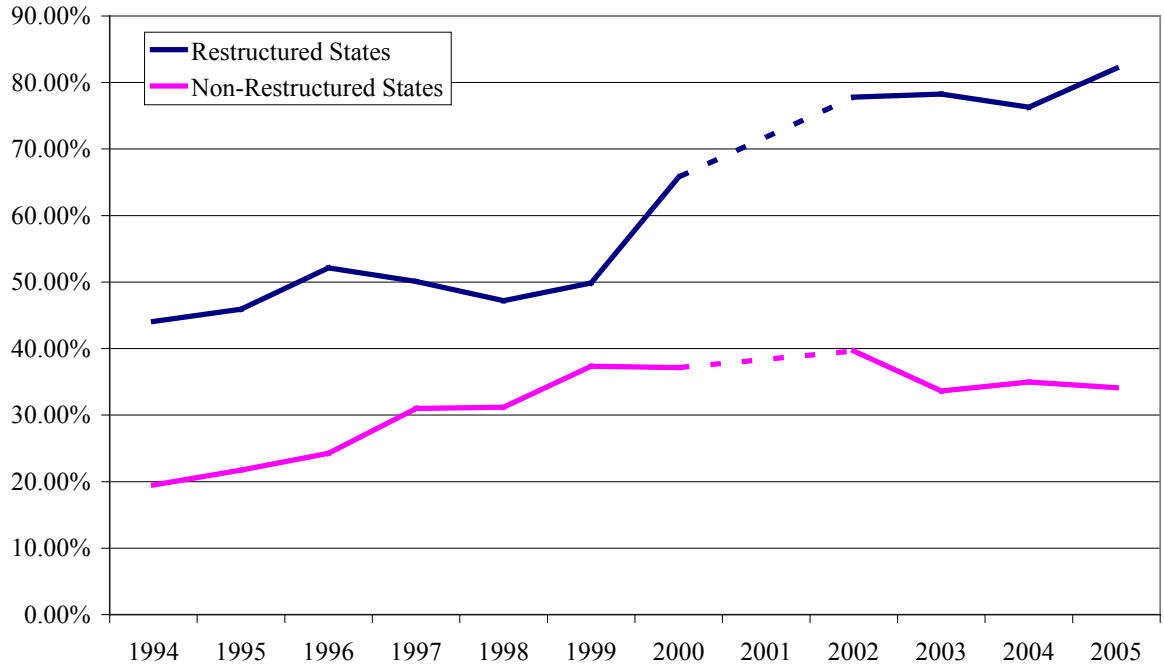
V. HOW BIG A PROBLEM IS IMPUTED DEBT?

Long-term wholesale power purchase contracts have been a source of supply for regulated utilities for many years, but before the 1980's most traditionally regulated utilities planned to meet their obligation to serve through their own generation resources. Growth in long-term PPAs was spurred by PURPA policies in the 1980s and became wide reaching after the Energy Policy Act of 1992 began the process of opening access to the FERC-regulated transmission grid. Over the last twenty years, IPPs have become major builders of power plants, owners of existing generation resources, and potentially low-cost new resources although the progress in this regard has been neither as smooth nor extensive as originally envisioned.

Regardless, the percentage of the power that utilities procure through PPAs has increased, particularly in jurisdictions where utilities have divested generation assets or where jurisdictions

have levied a requirement that a specified portion of a utility's power supply be from "renewable" energy resources. Currently 24 states and the District of Columbia have adopted renewable energy standards requiring that a fraction of the state's electricity be supplied by renewable energy resources.[38] California recently advanced its goal of having 20 percent of its energy supply from renewable resources to 2010 from 2017, and it also increased the goal for 2020 to 33 percent from renewable energy sources. The vast majority, if not all, renewable resources are expected to be developed under long-term, fixed-price PPAs. See Appendix A for a review of recent state precedent on this issue.

Purchases as a Percentage of Sales to Ultimate Customers



Source: Velocity Suite. Data for 2001 data was not included due to significant outliers.

The graph above clearly shows that the percentage of sales to ultimate customers from PPAs has increased over time. In addition, S&P recently published tables that show how S&P adjusts a

[38] Edison Electric Institute as of June 7, 2007.

utility's financial ratios to account for off-balance sheet liabilities.[39] For the seven companies for which S&P provides data in the report, the average book debt-to-capital ratio was about 58 percent prior to S&P's adjustments and about 63 percent after S&P's adjustments. In other words, the average debt-to-capital ratio used by S&P to evaluate the companies' credit rating is five percentage points higher than prior to S&P's adjustments. Depending on the business risk profile of the utility in question, this increase in the debt ratio could result in the utility's ratios being consistent with a lower credit rating.

For example, if a utility currently has an "Aggressive" financial risk indicator based upon its financial ratios, a change from a 58 percent to debt-to-capital to one with 63 percent places the utility in the "Highly Leveraged" financial risk indicator category for that ratio. Even if the utility had one of the two highest S&P business risk profiles of "Excellent" or "Strong", the change from "Aggressive" to "Highly Leveraged" changes the utility's likely credit rating from a low BBB to a low BB.[40] Other combinations of changes in financial ratios that could result in a change in the financial risk indicator could have similar effects. Of course, the rating agencies all caution against relying strictly on ratios to estimate the company's likely credit rating, but because a credit downgrade (particularly one from BBB to BB) would materially affect the terms and costs under which the utility could raise capital, it is important for ratepayers, the company and the regulator to be aware of the issue - imputed debt can be a big problem.

[39] Credit FAQ: "S&P Introduces Reconciliation Tables to Show Analytical Adjustments to Global Utilities' Financial Statements," *S&P Credit Ratings, Utilities,* October 11, 2006. This document was prepared prior to S&P's adoption of its most recent practices for determining imputed debt.

[40] See "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix", Standard & Poor's, *Ratings Direct,* November 30, 2007.

VI. MITIGATION OF THE IMPACT OF IMPUTED DEBT

Imputed debt increases a utility's financial risk and weakens its financial ratios. If the credit ratios weaken enough, the utility's credit rating may be downgraded or may be prevented from being upgraded. The increased cost of debt from a credit rating downgrade would be clear evidence of the adverse impact of imputed debt, but if there were no credit downgrade, is there any effect from imputed debt?

Yes. Debt holders and equity holders will require a higher return to compensate for the increased risk of default and increased financial risk.[41] Debt ratings are discrete, but the range of ratios for any particular rating is continuous. As a company's ratios weaken, the utility's credit strength approaches the next lower credit rating. If the ratios are allowed to continue to deteriorate, the credit rating will ultimately be downgraded. Moreover, the utility's credit ratios are known to the market. As the ratios weaken (strengthen), debt costs will increase (decrease) commensurately even though the credit rating has not yet been affected. The same logic applies to the cost of equity as acknowledged by, for example, the California PUC.[42] As financial risk increases, investors will require a higher expected rate of return on the company's stock. The increased cost of debt and equity from imputed debt cannot be avoided because the market will require compensation one way or another.[43]

[41] Even though both the cost of debt and the cost of equity increase, the overall after-tax weighted-average cost of capital ("ATWACC") will remain constant unless the increase in financial risk is sufficiently large to move the company into financial distress. Companies in financial distress frequently have a higher cost of capital than would be possible if the company had an investment grade credit rating.

[42] See, for example, California PUC, *Decision 04-12-048, Interim Decision*, ("CA D.04-12-048"), Rulemaking 01-10-024, Dec. 14, 2004, p. 83. See Appendix A for further explanations.

[43] From a theoretical point of view, this statement is not generally controversial, but it is difficult to substantiate empirically. The problem is that estimating the cost of capital is difficult. All estimation methods are subject to estimation error so distinguishing the effect of imputed debt on the cost of capital from other factors is hard. A full explanation of the reasons is beyond the scope of this paper.

Recognition by the regulator of the increased financial risk resulting from signing long-term or Evergreen PPAs[44] leads to the question of "what the regulator can and should do to mitigate the effect of imputed debt on the utility and rate payers?"

One task for regulators is to ensure that decisions regarding whether the utility should build a generator or sign a PPA are not unfairly weighted in favor of a PPA by ignoring the risk transfer to the utility. Ignoring the increased financial risk inherent in signing a long-term (or an evergreen) PPA would risk skewing the competition in favor of the PPA.

A. METHODS TO MITIGATE THE NEGATIVE FINANCIAL EFFECTS OF LONG-TERM PPAS

The overall goals of mitigating the negative effects of imputed debt should be to insure that investors, bondholders and equity holders, are treated fairly, while at the same time ensuring that the utility's customers are not overcharged. Although these goals are not controversial, the implementation of mechanisms that achieve them requires balancing the needs of investors and customers.

One method by which regulators can reduce the amount of imputed debt that results from a PPA is by adopting automatic cost recovery options that may influence S&P (and perhaps the other credit rating agencies) to reduce the risk factor assigned to the utility. For example, if the utility's risk factor were reduced from 50 percent to 25 percent, the amount of imputed debt would be reduced by 50 percent (i.e., 25/50). In other words, the regulator can reduce or perhaps eliminate the financial risk imposed on a utility from PPAs by adopting measures that decrease the level of uncertainty regarding full recovery of the costs of the PPA.

[44] As noted earlier, a series of short-term PPA contracts is termed "evergreen" when it is expected that the contracts will be replaced with an equivalent contract on a continuous basis as one contract expires.

The remainder of the discussion focuses on mitigating the effects of imputed debt from having signed a long-term PPA. Focusing on the increased financial risk or the weakened credit ratios suggests that there are two broad approaches to mitigation.[45] The first is to compensate the utility for the increase in financial risk, and the second is to restore one or more of the weakened financial ratios to its preexisting level prior to entering into the PPA.

Compensating for financial risk is the simplest (and generally the least expensive) way is to mitigate the effect of imputed debt, and this method is usually appropriate for utilities that have an investment grade credit rating. For non-investment grade utilities (or utilities that may suffer an imminent credit downgrade without mitigation) additional compensation based upon restoring some of the company's credit ratios may be appropriate. Regardless of the method chosen, it is essential that the utility's credit rating not be allowed to be adversely affected by signing long-term PPAs, because this would clearly increase the cost of the utility's debt (and its equity). The remainder of this section discusses the two broad approaches to mitigating the effects of imputed debt.

1. Mitigation Focused on the Increased Financial Risk

This first broad approach is best viewed a being part of a general rate proceeding. If a utility's credit rating is currently investment grade and not in danger of becoming non-investment grade, mitigation of financial risk is sufficient. To understand this approach, keep in mind that the return on equity (or ROE) investors require is a function of both the business risk and the financial risk of the utility in question. Imputed debt increases the financial risk of the company

[45] The credit rating agencies have taken no position on whether or how mitigation for the increased financial risk from PPAs could be provided. Some states such as Wisconsin, Colorado and Florida have essentially adopted mitigation in the form of an increase in the allowed regulatory equity ratio.

and thereby increases the required return on equity. There are two basic ways to compensate for the increased financial risk: the company can substitute equity for debt to restore the adjusted balance sheet (the balance sheet including imputed debt) to its pre-contract ratios of debt and equity, or the allowed ROE for the entire existing equity rate base can be increased. These two methods are discussed in more detail below.

a) Increase the Amount of Equity in the Rate Base

Signing a long-term PPA is equivalent in some ways to financing a new investment completely with debt. As a result, the ratio of debt to equity in the company's "adjusted" balance sheet is increased. For example, consider a utility's whose rate base consists of 45 percent equity and 55 percent debt before a contract was signed, and after signing the contract, whose adjusted balance sheet consists of 41 percent equity and 59 percent debt. In other words, the imputed debt from the PPA increased the adjusted debt ratio by four percentage points.[46] An obvious solution is to add enough real equity and reduce real debt to restore the *adjusted* capital structure to its pre-contract ratio of debt and equity.

To implement this approach, the utility would first calculate the total amount of imputed debt from its PPAs.[47] The utility could then issue an amount of equity and reduce an equivalent

[46] In S&P's publication, *S&P Introduces Reconciliation Tables to Show Analytical Adjustments to Global Utilities' Financial Statements, op. cit.*, the average "S&P adjusted" capital structure included approximately five percent more debt than did the non-adjusted capital structure.

[47] If the amount of imputed debt were expected to vary substantially over time, it may be more appropriate to estimate an average or levelized amount of imputed debt, so that the amount of compensating equity would not have to change each year.

amount of actual debt that restores the adjusted capital structure to the level before any debt was imputed or to a level that is deemed appropriate for the utility in question.[48]

For this approach to work, the regulator must allow an increase in the equity component of the rate base without simultaneously reducing the allowed ROE. The regulatory capital structure (with no recognition of imputed debt) now has a higher percentage of equity than it did before signing the PPA. The allowed rate of return on the adjusted rate base must be sufficient to compensate the utility's investors for the financial risk they carry from the "on the books" debt as well as the "off the books" (i.e., imputed) debt. The mitigation benefit would be eliminated if the allowed rate of return were reduced as soon as additional equity was issued by the utility. This approach restores the utility's debt ratio and its EBIT interest coverage ratio but will not restore its FFO/interest ratio and FFO/average debt ratio exactly.[49] The following example illustrates this point using S&P's calculation for imputed debt, depreciation[50] and interest expense.

Example 2: Recall Utility ABC had entered into a PPA with an amount of imputed debt of $106 million under S&P'S methodology. Assume that Utility ABC had a $1,000 million rate base consisting of 45 percent equity ($450 million) and 55 percent debt ($550 million).

[48] A variation on this method is to establish a hypothetical capital structure and allow a return on the hypothetical equity component that compensates for the increased financial risk. This will be discussed in the second broad method.

[49] In general, the FFO/Interest ratio will be over or under restored depending upon the starting values of the ratio.

[50] In the examples, average imputed depreciation (equivalent to straight line depreciation) is used. This is a simplification because in the S&P method imputed depreciation expense varies each year which makes the calculations more complicated.

Table 1

Regulatory Capital Structure Without Imputed Debt		
Debt	$550	55%
Equity	$450	45%
Total	$1,000	100%
Adjusted Regulatory Capital Structure Reflecting Imputed Debt		
Debt	$656	59%
Equity	$450	41%
Total	$1,106	100%

As shown in Table 1, the "adjusted" rate base ($1,106 million) consists of $450 million in equity but now $656 million in debt with an equity ratio of 41 percent and a debt ratio of 59 percent. To restore the adjusted rate base to its pre-contract values would require that the utility issue $47 million in equity and recall $47 million in debt resulting in an adjusted balance sheet of $608 million debt and $498 million in equity. See Table 2. Further, assume that the utility has a debt cost of 6.70%, cost of equity of 10.5%, and a tax rate of 40%. Then the After-Tax Weighted Cost of Capital can be determined with and without debt imputation as the equity-weighted cost of equity plus the debt-weighted after-tax cost of debt. See Table 2.

Table 2

Restored Capital Structure to Pre-Contract Level (with imputed debt)				
			Rate	**ATWACC**
Debt	$608	55%	6.70%	2.21%
Equity	$498	45%	10.50%	4.73%
Total	$1,106	100%		6.94%
Restored Capital Structure (without imputed debt)				
			Rate	**ATWACC**
Debt	$502	50%	6.70%	2.02%
Equity	$498	50%	10.50%	5.23%
Total	$1,000	100%		**7.25%**

As can be seen in Table 3, the additional equity fully restores the Debt to Total Capital ratio and the EBIT Interest Coverage ratios, but the other ratios are not fully restored.

Table 3

Ratios Before and After PPA

	Before PPA	With PPA and No Mitigation	With PPA and Mitigation
Debt to Total Capital	55%	59%	55%
FFO to Total Debt	0.27	0.23	0.26
FFO Interest Coverage	5.0	4.5	4.9
Adj. EBIT Interest Coverage	3.14	2.8	3.14

While the approach of issuing compensating equity is financially sound, it cannot easily be implemented on a contract by contract basis, because the cost of issuing small amounts of equity would be prohibitive. This method is best viewed as a means to mitigate a portfolio of PPAs in the context of a general rate case.

b) Increase the Allowed Return on Equity

The second method to mitigate the increased financial risk from imputed debt is to increase the allowed ROE. The increased return also mitigates some of the adverse impact on the utility's financial ratios, but does not fully restore any ratio. The question is how much to increase the allowed ROE? The answer to this question is relatively easy to estimate and is based upon the fact that a company's after-tax weighted-average cost of capital or ATWACC is constant for changes in capital structure within a broad middle range of capital structures for the companies in an industry.[51] Consider the following equation to calculate the ATWACC:[52]

$$ATWACC = r_D \times (1 - T_C) \times D + r_E \times E \qquad (1)$$

Where r_D = market cost of debt,

[51] For a complete discussion of this topic see "The Effect of Debt on the Cost of Equity in a Regulatory Setting," prepared by *The Brattle Group* for the Edison Electric Institute, January 2005.

[52] Note that this equation assumes that only debt and equity are in the capital structure, but one can add preferred equity to the equation if appropriate.

r_E = market cost of equity,
T_C = corporate income tax rate,
D = percentage of debt in the capital structure, and
E = percentage of equity in the capital structure.

The cost of equity consistent with the ATWACC, the market cost of debt and equity, the marginal corporate income tax rate and the amount of debt and equity in the capital structure can be determined by solving the equation above for r_E.

The change in the return on equity necessary to compensate for the increase financial risk from the PPA can be determined by first, calculating the pre-contract ATWACC based upon the pre-contract allowed rate of ROE, debt costs and tax rate, and then calculating the new allowed ROE that results in the same pre-contract ATWACC *after* the amount of imputed debt is added to the capital structure. This method results in exactly the same revenue requirement as the first method, but none of the utility's ratios would be fully restored to their pre-contract values because there is no reduction in interest expense from substituting equity for debt. This method recognizes the increased financial risk as if the utility had financed its investment completely with debt.[53]

Example 3

Recall Utility ABC had a capital structure consisting of $550 million debt and $450 million equity for a rate base of $1,000 million prior to entering into a PPA with an amount of imputed debt of $106 million (using S&P's methodology). As in Example 2, assume that Utility ABC prior to entering into the PPA had an allowed return on equity of 10.50% and an embedded cost of debt of 6.7 percent. As shown in Table 2 above the pre-contract ATWACC for Utility ABC was 6.94%. Table 4 illustrates how much the allowed return on equity should be increased to compensate the utility for the financial risk represented by the PPA.

[53] A depreciation expense equal to the annual capacity payment minus the imputed interest expense is added to the numerator in the FFO ratios. Therefore, the impact on these ratios has been moderated with S&P's recently revision of its imputed debt methodology.

Table 4

Regulatory Capital Structure Without Imputed Debt

	Dollar	Percent	Cost	**ATWACC**
Debt	$550	55%	6.70%	2.21%
Equity	$450	45%	10.50%	4.73%
Total	$1,000	100%		6.94%

Adjusted Regulatory Capital Structure
Reflecting Imputed Debt and Constant ATWACC

Debt	$656	59%	6.70%	2.38%
Equity	$450	41%	**11.19%**	4.55%
Total	$1,106	100%		6.94%

Regulatory Capital Structure Without Imputed Debt at Higher ROE

Debt	$550	55%	6.70%	2.21%
Equity	$450	45%	**11.19%**	5.03%
Total	$1,000	100%		**7.25%**

Notice that the ATWACC is identical in Table 2 and Table 4 (calculations 1 and 2), but the cost of equity has increased from 10.50% to 11.19%. Notice also the increase in the overall revenue requirement is $5.17 million for both. The increase in dollar return on equity is (11.19% - 10.50%) multiplied by $450 or $3.10 million after tax which result in $5.17 million before tax ($3.10/ (1-tax rate)) assuming a marginal income tax rate of 40 percent.

Increasing the allowed return on equity does not fully restore any of the financial ratios as can be seen in Table 5 below, but increased equity return is compensation for the increased financial risk. The advantage of this method is that the cost of issuing new equity is avoided.

Table 5

Ratios Before and After PPA

	Before PPA	**With PPA and No Mitigation**	**With PPA and Mitigation**
Debt to Total Capital	55%	59%	59%
FFO to Total Debt	0.27	0.23	0.24
FFO Interest Coverage	5.0	4.5	4.5
Adj. EBIT Interest Coverage	3.1	2.8	2.9

2. Mitigation Focused On Restoring Financial Ratios

The second broad approach focuses on (partially) restoring some of the financial ratios to their

pre-contract values. Because this approach is, in general, more expensive for rate payers than the first approach, it is only appropriate for a utility that does not have an investment grade credit rating or which is in danger of a downgrade to a non-investment grade rating if the negative effects of signing long-term PPAs are not addressed.

The distinguishing feature of the second approach is that mitigation is achieved by allowing a return on an amount of "imputed equity" that is calculated to offset the negative effects of imputed debt. The amount of imputed equity necessary can be targeted at compensating for any of the financial ratios. Unfortunately, there is no one solution that will restore all of the ratios that S&P relies on or the three ratios most heavily relied upon because calculation of the ratios relies upon different parts of the balance sheet and income statement. Therefore, the second approach requires a decision on which ratio should be restored or alternatively on what hypothetical capital structure to allow a return.

Because this method focuses on the utility's financial ratios, it can be applied as a "contract adder" on a contract by contract basis. Unlike the case in which new equity is issued or the appropriate ROE for the entire rate base is adjusted, the second method allows an equity return on an amount of imputed equity so there are no additional transactions costs with this method other than the process of approving the PPA and the determining the associated amount of imputed equity. Nor is it necessary to have a general rate case because the equity return on the imputed equity is simply the most recent commission-allowed ROE.

The "Financial Ratio Method," or ratio restoration, is designed to provide sufficient additional equity return to restore the utility's financial ratios to their pre-contract values over time. As mentioned above, S&P focuses on three financial ratios when evaluating the impact of imputed

debt.[54] Restoring each particular ratio requires a different amount of imputed equity. Although the EBIT interest coverage ratio is not currently among S&P's key financial ratios, it is the easiest (least expensive) ratio to restore to its preexisting value. Restoring the EBIT ratio will also partially restore the other three ratios. Assuming that the additional earnings are invested in additional assets that are recognized in the rate base, over time the other three ratios will also improve although they need not ever be fully restored. In general, the most expensive ratio to restore is the FFO/debt ratio.

One way to view this approach is to convert the PPA and its resulting imputed debt into a "mini-firm". The PPA generates the imputed debt and depreciation. The task is to determine an amount of imputed equity on which to earn an equity return that will restore the target ratio. Because the present value of future contract payments declines over the life of the contract, so does the amount of imputed debt. Therefore, the amount of imputed debt declines as well.

Implementing the financial ratio method requires the following steps:

- First, calculate the amount of compensating equity return that restores the target ratio when imputed interest expense and imputed depreciation are considered. The return earned on the compensating equity is assumed to be the same as the utility's allowed rate of ROE rate base from the most recent rate case.

- Second, calculate an adder to the cost customers pay per MWh (rate) for the contract(s).

Example 4: Continuing the previous example, assume that the utility expects to receive about 1.4 million MWh per year from the PPA contract. It is possible to calculate the additional cost per MWh for each year the contract is in effect to restore the EBIT interest expense ratio. This is done in Table 6 below.

[54] S&P has de-emphasized the EBIT ratio. See S&P's Research: "New Business Profile Scores Assigned for U.S. Utility and Power Companies: Financial Guidelines Revised," June 2, 2004.

Table 6

Year	Present Value of Capacity Payment	Imputed Debt	Compensating Hypothetical Equity	Compensating Before-Tax Equity Return	Contract Adder ($/MWh)
1	$425.1	$106.29	$87.0	$15.2	$10.9
2	$414.4	$103.61	$84.8	$14.8	$10.6
3	$403.0	$100.75	$82.4	$14.4	$10.3
4	$390.8	$97.70	$79.9	$14.0	$10.0
5	$377.8	$94.45	$77.3	$13.5	$9.7
6	$363.9	$90.97	$74.4	$13.0	$9.3
7	$349.1	$87.27	$71.4	$12.5	$8.9
8	$333.3	$83.32	$68.2	$11.9	$8.5
9	$316.4	$79.10	$64.7	$11.3	$8.1
10	$298.4	$74.60	$61.0	$10.7	$7.6
11	$279.2	$69.80	$57.1	$10.0	$7.1
12	$258.7	$64.67	$52.9	$9.3	$6.6
13	$236.8	$59.21	$48.4	$8.5	$6.1
14	$213.5	$53.37	$43.7	$7.6	$5.5
15	$188.6	$47.15	$38.6	$6.8	$4.8
16	$162.0	$40.51	$33.1	$5.8	$4.1
17	$133.7	$33.42	$27.3	$4.8	$3.4
18	$103.4	$25.86	$21.2	$3.7	$2.6
19	$71.2	$17.79	$14.6	$2.5	$1.8
20	$36.7	$9.18	$7.5	$1.3	$0.9

In the table, the imputed debt in each year is the present value of the remaining future capacity payments multiplied by 25%. The compensating equity is calculated as Utility ABC's regulatory equity to debt percentage multiplied by the imputed debt. Compensating equity return is calculated as the after-tax cost of equity (10.5%) divided by (1 – tax rate) or (1 – 40%). Finally, the contract adder is calculated as the compensating equity return divided by the expected MWh per year.

As noted above this method restores the EBIT interest coverage ratio but it does not fully restore other ratios. Of course, as each year passes, the amount of imputed debt for a contract declines because there are fewer future contract payments, so the dollar amount of compensation also declines. This happens even though the formula to calculate the amount of mitigation is unchanged. Depending on the individual utility's circumstances, it may make sense to levelize the adder, so that the same dollar amount is added to the cost of electricity each and every year during which the contract is in effect. This method can be adjusted to focus on any of the other

financial ratios. The required compensation will be greater depending upon which ratio is the focus of the compensation.

Example 4 Continued: Table 7 below shows the amount of compensating equity that is needed to restore each of the four ratios in the first year. Because this method envisions using imputed equity, the debt ratio is never affected.

Table 7

Equity Required to Restore Ratios

	S&P Metholodogy
Debt to Total Capital	na
FFO to Total Debt	$220
FFO Interest Coverage	$220
EBIT Interest Coverage	$87

The EBIT Interest Coverage ratio requires the least compensation to restore. The reason that the two FFO ratios require the same amount of imputed equity is that the calculations assume imputed depreciation is recovered straight line as opposed to S&P's method for ease of exposition.

B. COMPARISON OF MITIGATION METHODS

The advantage of the method utilizing imputed equity to offset imputed debt is that it can be applied on a contract-by contract basis between rate cases and does not require the utility to issue additional equity. Restoring the three main financial ratios is generally more costly than compensating for financial risk, but hypothetical equity can restore any particular financial ratio. For a utility with a non-investment grade credit rating, restoring the financial ratios will help prevent a credit downgrade more than simply compensating for financial risk. However, both methods compensate the utility for the risk inherent in PPAs and improve its financial ratios relative to doing nothing. Focusing solely on the increased financial risk is less costly to consumers than is the financial ratio method, but it also takes longer to restore the company's other financial ratios to their pre-contract levels.

VII. CONCLUSION

(1) Long-term purchase power agreements (PPAs) transfer financial risk from the seller to the buyer. This is because PPAs obligate the buyer's future cash flow, just like a debt service obligation.

(2) Policy makers should be particularly sensitive to PPA-related risk transfer in situations where the utility's credit rating is minimally investment-grade. For such utilities, entering into PPAs without addressing debt imputation could trigger credit downgrades which push the utility below investment-grade - with consequences that are far more harmful to customers than downgrades to levels that are still investment-grade. The risk transfer from PPAs must still be considered for utilities which are strongly investment-grade although the consequences of a credit rating downgrade are not likely to be as severe.

(3) Regulatory policies which provide assurance of PPA cost recovery can effectively mitigate the impact of imputed debt on the credit rating of purchasing utilities. S&P's methodology, in particular, applies a risk factor to the debt calculation which is intended to reflect the probability that PPA costs will be fully recovered in rates. The greater the probability, the smaller the risk factor, and the smaller the amount of imputed debt from a particular set of contracts.

(4) There is no perfect solution to the problem of PPA-related risk transfer and imputed debt. There are at least three possible approaches to addressing the problem. Unfortunately, none simultaneously maximizes the protection of credit worthiness, while minimizing the cost to consumers.

(5) In competitive procurement situations, it is important that imputed debt be addressed in a competitively neutral way. Imputed debt should not be used to exclude merchant generators from the market, but neither should it be ignored. Adjustments should be based on the true

costs involved (e.g., by increasing bid prices by no more than is required to restore interest coverage ratios to pre-PPA levels).

APPENDIX A

TREATMENT OF IMPUTED DEBT IN CERTAIN STATES

This appendix discusses selected states where policy makers, i.e., legislatures or regulatory commissions, have looked at the issue of imputed debt, or debt equivalence, for long-term purchased power contracts. One application is in cost of capital hearings and deals with the impact of imputed debt on the financial strength of the utility, its regulatory capital structure, and the allowed return on equity. A second application is the mitigation of increased financial risk with a cost adder to the price upon signing specific long-term PPAs. A third area is in the evaluation of "buy versus build" situations[55] comparing the competitive bids of independent power producers and regulated utilities for new generation in states with hybrid generation markets.[56] Policy makers analyzing imputed debt generally recognize that credit rating agencies, especially S&P, calculate imputed debt and adjust critical financial ratios accordingly. The policy outcomes are varied, with some states providing for explicit mitigation of imputed debt,

[55] A buy-versus-build situation occurs when a competitive procurement proceeding is held and the decision on which is the lowest cost alternative (i.e., lowest present value of future revenue requirements) includes making a choice between the lowest cost power purchase option in comparison with the utility's best self-build option. The utility's self-build option will include its proposed capital structure, which will help determine its final cost. The new generation addition would normally mirror that of the utility as a whole and leave the utility's financial risk profile unchanged. If, purely hypothetically, the utility were to use 100 percent debt financing with no additional equity and equity return, the utility's financial risk would go up, as measured by the S&P financial ratios. As a general proposition (before looking at the specifics of a given situation), the signing of the long-term PPA has the effect of increasing debt equivalence without increasing return (mediated through the imputed debt calculus discussed above). Therefore, in comparing that PPA alternative with self-build options at allowed capital structure, the mitigation of cost of imputed debt to the utility needs to be added to the contract the utility signs to make the comparison "apples to apples." See Standard & Poor's *Utilities & Perspectives*, "'Buy Versus Build': Debt Aspects of Purchased-Power Agreements," May 2003 and, for an opposing view, Electric Power Supply Association, *Electric Utility Resource Planning - The Role of Competitive Procurement and Debt Equivalency*, prepared by GF Energy LLC, July 2005.

[56] A hybrid generation market, which, as discussed below, California has become and Delaware could now become under new law, is where resource procurement for new supplies is accomplished with open bidding among independent power producers and regulated, cost-of-service utilities.

and some states choosing not to mitigate in the cases reviewed. States discussed here (California, Delaware, Florida, Nevada, New Mexico, and Wisconsin) have all considered how and whether to address imputed debt.[57] Brief summaries of these states' treatments are provided below. There is first an indicative discussion of the reasons why many states have not addressed imputed debt.

States for which Imputed Debt is not Currently an Issue

Although S&P applies its imputed debt methodology to all utilities issuing debt, state regulatory commissions or legislatures are not likely to consider imputed debt to be a material policy issue if the state's utilities do not have significant existing or prospective long-term PPAs. States in this situation include primarily those with a traditional industry structure where utilities own and continue to build all generation necessary to meet their obligation to serve. Additionally, in "retail access" states, of which there are currently seventeen, the utilities' first obligation is to provide reliable, low-cost transmission and delivery service, and, in many such states, to purchase a substantial amount of electric power to meet their obligations as Provider of Last Resort ("POLR"). Most of the POLR contracts have historically been for short terms, generally three years or less.[58] Before S&P changed its methodology, such shorter term contracts generated little or no imputed debt. This has changed, and S&P now treats short-term contracts in an "evergreen" manner, i.e., assuming they will be renewed indefinitely and therefore warrant

[57] This discussion is not intended to be exhaustive. It omits discussion of several states where the discussion has begun, but where the authors are not aware of the final outcome, including OR, LA. UT is also omitted.

[58] Note: the term "state" is always used in these discussions to include the District of Columbia (DC), for convenience of exposition. The seventeen "retail access" states are: CT, DE, DC, ME, MD, MA, MI, NH, NJ, NY, OH, OR, PA, RI, TX, VA. The situation in DE may be changing, as discussed below.

imputed debt treatment. Policy makers in retail access states are now likely to be asked to address the resulting effect of imputed debt on the credit ratings of the states' utilities.[59]

Moreover, heavy reliance on short-term contracts for power procurement does not appear to be a viable long-term policy for all of the retail access states for two reasons. First, the higher level of electric price volatility may be unacceptable to ratepayers and regulators, as experienced in the recent period of natural gas price inflation and the resulting higher electric prices. Second, short-term contracts and spot market sales do not appear to provide strong enough incentives for investment in adequate new generation. Fitch Ratings stated its view position on short-term contracts: ". . . the one-to-three-year term of such supply agreements is, in Fitch's view, too short to provide a financial foundation on which to fund the construction of new independent power generation."[60]

In contrast, there is little question that long-term contracts signed under regulatory guidance by financially sound utilities can be used to finance new power plants. Fitch also predicts that retail access states within regional transmission organizations (RTOs) may have to become more active and may well move toward hybrid market structures, with long-term procurement processes more akin to what are found in California. Moreover, the authors of this report conclude that the Fitch analysis recognizes the transfer of risk from the power producer to the purchasing utility by the signing of a long-term purchased power contract. This risk transfer is related to the risk that S&P identifies in its calculation of imputed debt for the contract buyer.

California

[59] Standard & Poor's, "Imputed Debt Calculation for U.S. Utilities' Power Purchase Agreements," March 30, 2007.

[60] Fitch Ratings,"Stimulating Generation Additions in Deregulated States," *Op. Cit.*, November 4, 2005, at p. 2. This was discussed above in Section II.

The Public Utilities Commission of California (CPUC) revised its policy in December, 2007 so that utilities are no longer allowed to adjust (increase) independent power producers' (IPP) bid prices by using a 20% risk factor in comparing them to self-build options. The Commission continues to consider debt equivalence in determining utilities' costs of capital.[61] For the 2005 test year, the CPUC approved a 4% increase in Southern California Edison's preferred equity ratio and a corresponding decline in SCE's long-term debt ratio (all measured on a ratemaking basis). More recently, the Commission has rejected attempts by San Diego Gas & Electric to establish an automatic mechanism to increase SDG&E's equity ratio to offset the FIN(46) effects of PPAs.

The CPUC previously had recognized that debt equivalence is a real economic cost that can impact a utility's credit rating and cost of borrowing, and had allowed the use of a 20% debt equivalence factor in comparing PPAs to self build options. The Commission changed its policy out of concern that explicitly recognizing the cost of PPA risk transfer "…creates a disparity between the treatment of PPAs and utility-owned projects in the procurement process…" because no such adder is applied to self-build options.

In effect, the policy in California now is to ignore PPA risk transfer during procurement decision making and address its consequences after the fact: "We recognize that at some point, DE *may* reach a point where it can affect the utilities' credit rating and cost of capital, and it is not disputed in this proceeding that the potential effect of DE on credit ratings, if any, is an appropriate topic for the utilities' cost of capital proceedings." However, all three large California electric utilities have applied for rehearing of this decision, so it is possible that the Commission may revise its policy once again.

Delaware

[61] CPUC, *Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison Company's, and*

Delaware has been among the states pursuing a policy of retail competition, but had the misfortune to end its capped-price transition period on May 1, 2006, after the recent inflation in electric prices. Apparently, the majority of residential and small commercial customers were forced to move to a higher priced "Standard Offer Service," which was procured through short-term auctions and that reflected the volatility that is inherent in a short-term strategy.

The General Assembly passed a revision to the restructuring legislation entitled "The Electric Utilities Retail Supply Act of 2006." The Act provides that all regulated electric distribution companies will henceforth be designated as the standard offer service supplier and returning customer service supplier in their respective territories. Moreover, the distribution companies now are given new opportunities and responsibilities to enter into long-term and short-term supply contracts, to own and operate generation facilities, to build generation and transmission facilities, to make investments in demand-side resources and to take any other Commission approved action to diversify their retail load supply. This has ushered in the issue of imputed debt in an essential way.

On August 1, 2006, in response to Commission directives, Delmarva Power and Light (Delmarva) filed a draft RFP. There has been a substantial amount of discussion about the terms and conditions of the RFP, particular in three areas: imputed debt cost factors in bid evaluation, credit and operational security requirements, and variable interest entity treatment under FASB Interpretation No. 46.[62] Delmarva has proposed that in order to account for the effect of imputed debt on its balance sheet and credit rating, there would be a cost adjustment added to each long-

San Diego Gas & Electric Company's Long-Term Procurement Plans, Decision 07-12-052, December 20, 2007.

[62] See New Energy Opportunities, Inc et al., *Analysis and Recommendations Regarding Delmarva Power and Light Company's RFP*, September 18, 2006, "Section viii. Imputed Debt Offset" and Concentric Energy

term bid. This adjustment would be based on an S&P calculation of imputed debt.

Delmarva argued that where a bid is compared with Delmarva's self-build option, the NPV of revenue requirements would generally include the impact of additional debt and equity in proportion to Delmarva's allowed capital structure and debt and equity costs from the most recent rate decision. The need to maintain the appropriate equity thickness is built into the cost structure of the self-build options. The cost adder puts contracts on a comparable footing in terms of mitigating the degradation in Delmarva's financial ratios.

On November 21, 2006, the Delaware Public Service Commission issued Order No. 7081, which found that Delmarva's (DP&L) imputed debt adjustment should be used in their RFP. The Order says[63]

> 145. We believe that the RFP should provide that DP&L will be permitted to assess the incremental equity amount to be equal to 30% of the net present value of the bid's capacity payment, and that a portion of the energy price may also be included if DP&L concludes that a portion of the bid's energy component would be imputed as debt by rating agencies in their assessment of DP&L's creditworthiness.

Florida

The Florida Commission first addressed imputed debt in 1999 by approving a stipulation and settlement that explicitly mitigated the impact of imputed debt. The settlement did so by setting the level of equity that Florida Power & Light (FP&L) was allowed in its capital structure for surveillance reporting requirements and all regulatory purposes, on a basis that was adjusted for

Advisors, *An Assessment of the Risks of the Independent Consultant's Proposed Modifications to Delmarva's RFP for New Generation Resources*, Oct. 30, 2006.

[63] Delaware PSC, PSC Docket No. 06-2111, Order No. 7081, Nov. 21, 2006, p. 4.

imputed debt.[64] This policy of having an explicit equity adjustment in the capital structure was continued with the approval of subsequent orders, including that in 2005, where in Paragraph 15 states:[65]

> For surveillance reporting requirements and all regulatory purposes, FPL's ROE will be calculated upon an adjusted equity ratio, as follows. FPL's adjusted equity ratio will be capped at 55.83% as included in FPL's projected 1998 Rate of Return Report fro surveillance purposes. The adjusted equity ratio equals the common equity divided by the sum of common equity, preferred equity, debt and off-balance sheet obligations. The amount used for the off-balance sheet obligations will be calculated per the Standard & Poor's methodology. [Emphasis added]

Thus, the Florida Commission mitigates the financial impact of imputed debt by increasing the utility's equity "thickness." The approach is based directly on the S&P methodology for calculating imputed debt. The Commission explicitly recognized the effect that purchased power contracts have on the utility's financial ratios as calculated by S&P. The Commission approved the 1999 settlement that capped FPL's adjusted equity ratio at 55.83 percent — which at that time equated to a ratio of 65.7 percent based on the regulatory books absent imputed debt.[66] Thus, to offset the greater financial leverage associated with its imputed debt, FP&L was allowed to increase its actual equity ratio as long as the "adjusted equity ratio" (i.e., the equity ratio calculated to include imputed debt) did not exceed 55.83 percent.

The Florida Commission also considered imputed debt in its approach to making long-term resource planning decisions. The Florida Commission requires its utilities to account for the

[64] Florida Public Service Commission, *Order Approving Stipulation and Settlement,* Docket No. 990067-EI, Order No. PSC-99-0519-AS-EI, issued on March 17, 1999.

[65] Florida PSC, *Order Approving Stipulation and Settlement*, Docket No. 050045-EI, Docket No. 050188-EI, Order No. PSC-05-0902-S-EI, Issued Sept. 14, 2005; and *Stipulation and Settlement*, Same Dockets, dated Aug. 22, 2005, Paragraph 15.

costs that purchased power contracts impose on utilities through imputed debt.[67] To do this, FP&L employs an equity adjustment to calculate the additional costs associated with the amount of imputed debt based on S&P's imputed debt calculation for the specific contract under discussion. This cost is added to the cost of the contract for making comparisons with other resource options. The 1999 order approved the use of a 10 percent risk factor, noting that this was the factor then assigned by S&P.[68] However, in 2004 the Florida Commission increased the risk factor to 30 percent, explaining that six months earlier S&P had issued a report stating that it now applied a 30 percent risk factor in the determination of the consolidated credit profile of the FPL Group.[69]

Nevada

In 2001, Nevada adopted what was at the time one of the country's more aggressive renewable portfolio standards ("RPS"). The law requires that 15 percent of all electricity generated in Nevada be derived from new sources of renewable energy by the year 2013. This required that the state's utilities, Nevada Power Corp and Sierra Pacific Power Corp, sign a substantial number of new, long-term contracts for renewable power. Early progress was modest, in part because these utilities were emerging from a period of financial distress with below investment grade bond ratings, stemming from the western energy crisis.

In June 2005, the Nevada legislature passed Assembly Bill 3 ("AB3") that modified Nevada's RPS. The new law increased the target percentages for energy from renewable resources, now requiring that by 2015, 20 percent of all electric power be from renewable energy resources. At

[66] Order No. PSC-99-1713-TRF-EG, Docket No. 990249-ET, September 2, 1999, p. 9. See also Provision 4 of *Stipulation and Settlement*, Before the Florida Public Service Commission, Docket No. 990067-EI, March 10, 1999.

[67] F.A.C. Rule 25-22.081, paragraph 7.

[68] Order No. PSC-99-1713-TRF-EG, Docket No. 990249-ET, September 2, 1999, p. 9.

the same time, the legislature recognized that the goal of significantly increasing the number of renewable energy contracts signed would be difficult without proactively addressing the issue of imputed debt. The utilities were concurrently engaged in strong efforts to regain an investment grade bond rating. AB3 addresses imputed debt directly by requiring the following:[70]

7. The Commission shall adopt regulations that establish:

> (a) Standards for the determination of just and reasonable terms and conditions for the renewable energy contracts and energy efficiency contracts that a provider [of electric service] must enter into to comply with its portfolio standard.
>
> *(b)* ***Methods to classify the financial impact of each long-term renewable energy contract and energy efficiency contract as an additional imputed debt of a utility provider. The regulations must allow the utility provider to propose an amount to be added to the cost of the contract, at the time the contract is approved by the Commission, equal to a compensating component in the capital structure of the utility provider. In evaluating any proposal made by a utility provider pursuant to this paragraph, the Commission shall consider the effect that the proposal will have on the rate***. [Emphasis added]

The Public Utility Commission of Nevada (PUCN) implemented this requirement in a set of rules, NRS 704.7821(7) (b).

In May 2006, Sierra Pacific Power Company (SPPC) filed for the approval of a renewable contract negotiated to partially meet the renewal portfolio standard. The filing included the request for mitigation of imputed debt through a cost adder, which followed SPPC's interpretation of the AB3. However, SPPC withdrew the request for mitigation of imputed debt of the contract in late summer of 2006, reserving the right to re-file. Therefore, at this time, there has been no test of whether the PUCN would approve any particular cost adder on a renewable contract as imputed debt mitigation based upon their interpretation of the 2005 law.

New Mexico

[69] Florida PSC, Order No. PSC-04-0249-TRF-EQ, issued on March 5, 2004, in Docket No. 031093-EQ

The New Mexico Renewable Energy Act (REA), at NMSA 1978, § 62-16-4(D), requires New Mexico's investor-owned electric utilities to file a procurement plan each year that includes the cost of any new renewable energy resource required to comply with the RPS. The 2007 Plan of Public Service of New Mexico (PNM) requested that the New Mexico Public Regulation Commission (NM Commission) approve both the "Biomass PPA," a long-term purchased power agreement for renewable energy from a biomass plant, and the recovery of the costs of the Biomass PPA.[71] In addition to the costs for capacity and energy, PNM sought approval to mitigate the financial impacts of imputed debt through the approval of an adder, which would be later collected in rates when the biomass plant was built and renewable power began to be supplied.

The statutory language on cost recovery for renewable energy, in NMSA 1978, § 62-16-6, states:

> A public utility that procures or generates renewable energy shall recover, through the rate-making process, the reasonable costs of complying with the renewable portfolio standard. Costs that are consistent with commission approval of procurement plans . . . shall be deemed to be reasonable.

PNM's proposal analyzed the Biomass PPA's imputed debt impacts in terms of the S&P methodology, which was used to determine the degree to which the three key financial ratios would be degraded (Funds from Operations (FFO) interest coverage; the FFO to Debt ratio; and the Total Debt to Total Capital ratio). The mitigation requested was a cost adder equal to the net return on a "compensating equity adjustment." This is the amount of equity that, if PNM were to issue and use to retire real debt, would restore PNM's debt-to-capital ratio to its pre-Biomass PPA level. The concept and formula used were generally the same as used in the state of Florida

[70] See State of Nevada, Assembly Bill No. 3 – Committee of the Whole, Section 29.7 (b), p. 21. http://www.leg.state.nv.us/22ndSpecial/bills/AB/AB3_EN.pdf.

[71] Public Service Company of New Mexico, Notice of Filing of "Renewable Energy Portfolio Procurement Plan for 2007," Case No. 06-00340-UT, August 16, 2006.

to make imputed debt adjustments discussed above.

However, the Commission approved only the energy and capacity costs of the Biomass Contract and denied approval of the cost of imputed debt in the context of this proceeding, which covered renewable plan and contract approval.[72] No party contested the fact that signing the Biomass contract would degrade PNM's financial ratios, other things equal. The Commission appears to have reasoned that the degradation of financial ratios in the degree indicated is not sufficient without evidence that a bond downgrade was likely to follow. Although PNM had an S&P rating of BBB/Negative, the Company did not contend that signing this long-term Biomass contract alone would be likely to change its credit ranking. The Commission also appeared to determine that the degraded financial ratios were also insufficient evidence that the cost of capital would increase, and therefore, rejected the cost adder sought. In accordance with the Recommended Decision of the Hearing Examiner, PNM was left with the opportunity to raise the issue of the financial impact resulting from the Biomass contract (and possibly other off balance sheets obligations) in another docket. The Recommended Decision states "While we deny PNM's request in this case concerning imputed debt, PNM will have a full and fair opportunity to present this matter in its next rate case."[73]

[72] New Mexico Public Regulation Commission, *Final Order on Exceptions*, Case No. 06-00340-UT, Dec. 18, 2006. There are many other issues discussed.

[73] Lee Huffman, *Recommended Decision of the Hearing Examiner*, NMURC Case No. 06-00340-UT, Nov. 29, 2007, p. 20.

Wisconsin

Wisconsin sets a common equity ratio target based on what they call a "Financial Capital Structure" that includes off balance sheet items (including imputed debt on PPA's) that supports, in their view, a given rating. This then sets the amount of equity that will be included in the "Regulatory Capital Structure" in setting rates. The effect is to allow the company to carry a thicker equity ratio and have it considered within the ratemaking process. In WPSC's last case its financial equity target was 52%. This ratio is intended to support a credit rating between an A and an AA, and translated into a regulatory equity target ratio (close to GAAP) of 57.46%. The difference (5.46%) represents equity that has been added to offset imputed debt associated with purchase power and operating lease commitments.[74]

[74] PSC of Wisconsin, *Final Decision*, 6690-UR-118, January 15, 2008

Testimony of
Jeremy J. Newberger

DIRECT TESTIMONY

OF

JEREMY J. NEWBERGER

Introduction and Qualifications

Q. Please state your name and business address.

A. My name is Jeremy J. Newberger. My business address is 40 Sylvan Road, Waltham, Massachusetts.

Q. By whom are you employed and in what capacity?

A. I am employed by the National Grid USA Service Company (Service Company), which provides services to The Narragansett Electric Company d/b/a National Grid (National Grid or the Company). I am Manager for Energy Efficiency Policy and Evaluation in the Service Company's Rhode Island Strategic Business Policy and Evaluation Group.

Q. Please describe your education and professional background.

I received a Bachelor of Science degree in Thermomechanical Engineering and Energy Conversion from the University of Illinois at Chicago and I received a Master of Science degree in Technology and Policy from the Massachusetts Institute of Technology. Since 2011, I have been in my current position with management oversight of Rhode Island energy efficiency planning, stakeholder and regulatory relations, evaluation and reporting. I also coordinate the regional avoided energy supply component (AESC) study and manage the Company's participation for Massachusetts and Rhode Island with energy efficiency and Combined Heat and

Power in ISO-NE's forward capacity market. I have been at National Grid and its predecessor companies since 1994. Prior to my current position, I was the Manager of Energy Efficiency Policy and Regulatory Affairs for New England. Through this position and others at National Grid, I have had various responsibilities in the areas of energy efficiency evaluation, cost effectiveness modeling, avoided costs, energy efficiency program design, transmission market developments and targeted energy efficiency. Before working at National Grid, I held positions at Sieben Energy Associates, an energy efficiency consulting firm in Chicago, Pacific Gas and Electric Company in San Francisco, and Energy Investment, Inc., an energy engineering consulting firm in Boston.

Q. Have you previously testified in any formal hearings before regulatory bodies?

A. Yes, I have previously testified before the Rhode Island Public Utilities Commission (PUC) on matters related to energy efficiency for the past ten years, most recently in Docket No. 4580 regarding the Company's Energy Efficiency Program Plan for 2016. I have also testified before the New Hampshire Public Utilities and Massachusetts Department of Public Utilities on behalf of Company affiliates and the California Energy Commission on behalf of the Pacific Gas and Electric Company. I am also the Company's representative to the Executive Committee of the Rhode Island Energy Efficiency and Resources Management Council.

Q. What is the purpose of your testimony?

A. The Company administers aggressive energy efficiency programs pursuant to Rhode Island law. My testimony will describe the role that these Energy Efficiency programs play in the evaluation of the resource alternatives for the development of natural gas transportation and storage capacity.

Q. Is the Company sponsoring other witnesses to support this filing?

A. Yes. The joint testimony of Messrs. Timothy Brennan and John E. Allocca, Director in the Regulatory Strategy and Integrated Analytics Group and Director of Gas Contracting and Compliance, respectively, provides an overview of the Company's filing requesting approval of a resource contract with the Algonquin Gas Transmission Company for the proposed "Access Northeast" project. Messrs. Brennan and Allocca's testimony provides a listing of the testimonies offered in support of the proposed contract.

Q. Please describe the Energy Efficiency programs administered by the Company in Rhode Island.

A. National Grid currently operates comprehensive energy efficiency programs targeting the residential, low-income, and commercial and industrial (C&I) customer sectors. These programs are currently operated pursuant to the 2015-17 Least Cost Procurement Plan approved by the PUC in 2014 in Docket No. 4522, and by the 2016

Energy Efficiency Program Plan approved in Docket No. 4580. The Company's energy efficiency programs have been ranked first in the country for utility-sponsored energy efficiency programs by the American Council for an Energy-Efficient Economy (ACEEE) in 2014, and 2015, receiving the maximum score[1]. Since 2009, National Grid has invested approximately $430 million, saving customers 1,000,000 MWh of electricity, 157 MW of peak electric load, and 18 million therms of natural gas. National Grid has a consistent and successful track record of contributing to the achievement of Rhode Island's ambitious efficiency goals and in cooperating with all stakeholders in the development of these programs in the process.

Q. Please describe how Rhode Island's energy efficiency targets are determined.

A. In Rhode Island, Energy Efficiency Plans are developed in three-year cycles. Each cycle begins with a proposal of targets by the Rhode Island Energy Efficiency and Resources Management Council (EERMC). The EERMC was formed by the "The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006" to "evaluate and make recommendations, including, but not limited to, plans and programs, with regard to the optimization of energy efficiency, energy conservation, energy resource development; and the development of a plan for least-cost

[1] The 2015 State Energy Efficiency Scorecard, October 2015, Report U1509, American Council for an Energy-Efficient Economy, Washington, DC.

procurement for Rhode Island."[2] The EERMC includes a wide range of stakeholders, including environmental, business, municipal, low income, and other interests. The EERMC's approach to setting targets has begun with Opportunities Reports for electricity, natural gas, and other resources. These reports were developed in 2010-12 and were designed to cover a ten year period. The reports helped inform the 2012-14 targets. Subsequent application of the findings of these reports has involved the EERMC making adjustments for market conditions, new technologies, and evaluation reports. Once the targets are approved by the PUC, the Company designs its three-year and annual energy efficiency plans to meet those targets. The most recent proposal and approval of targets, for 2015-17, may be found in PUC Docket No. 4443.

Q. Could the Rhode Island energy efficiency programs be more ambitious?

A. No. The PUC and the statute governing these efforts require that:

> "[l]east-cost procurement shall comprise system reliability and energy efficiency and conservation procurement as provided for in this section and supply procurement as provided for in § 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical and natural gas energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible."[3]

Therefore, the Company's energy efficiency plans could not be more ambitious. The "prudency" provision has been variably interpreted to govern both the aggressiveness

[2] R.I. Gen. Laws § 42-140.1-3

[3] R.I. Gen. Laws § 39-1-27.7

of program expansion as well as the rate and bill impacts of energy efficiency budgets. The process designed by The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 is intended to provide exactly this kind of review and oversight. The EERMC, the PUC, the Company, and the Company's customers are all motivated to achieve maximum value. Rhode Island is consistently a top performing state with respect to delivering Energy Efficiency opportunities and the programs could not be more ambitious.

Q. Are you aware of any case where energy efficiency and pipeline capacity were evaluated as alternatives to one another?

A. Yes. While I am not aware of any such cases in Rhode Island, I understand that energy efficiency and pipeline capacity were evaluated as alternatives to one another in Massachusetts proceedings involving the Company's affiliates, Boston Gas Company and Colonial Gas Company. In D.P.U. 13-157 and D.P.U. 15-34, the Massachusetts Department of Public Utilities (MADPU) approved precedent agreements filed by Boston Gas Company and Colonial Gas Company, each d/b/a National Grid (referred to hereinafter as Boston Gas and Colonial Gas, respectively) for additional pipeline capacity. The MADPU's Orders in D.P.U. 13-157 and D.P.U. 15-34 each made two findings: 1) Boston Gas Company and Colonial Gas Company's energy efficiency efforts were already consistent with achieving all cost effective

energy efficiency;[4] and 2) "[a]lthough savings from gas energy efficiency programs are reliable and verifiable, unlike gas supply resources, gas energy efficiency and demand response resources are not dispatchable resources on which LDCs can rely to meet design day or design season customer demand."[5]

Q. Are electric energy efficiency resources subject to the same non-dispatchable constraint as gas energy efficiency?

A. Yes, electric energy efficiency resources, with the exception of Combined Heat and Power, are predominantly non-dispatchable. Moreover Combined Heat and Power resources, if dispatched, are predominantly fired by natural gas, so dispatching Combined Heat and Power resources to alleviate a gas pipeline constraint is simply reducing consumption by one gas-fired electric generation resource, and increasing it at another.

[4] *See* Boston Gas Company and Colonial Gas Company each d/b/a National Grid, D.P.U. 13-157 at 23 (2014) (*citing* D.P.U. 12-103 at 161*). See also* Boston Gas Company d/b/a National Grid, D.P.U. 15-34 at 37 (2015) (*citing* D.P.U. 12-103 at 161).

[5] *See* D.P.U. 13-157 at 23 (2014).

Q. Given the need for natural gas expansion and the requirements of the Company's RFP in this proceeding for a regional scale solution on the order of 0.5 to 2.0 BCF, does incremental energy efficiency have the ability to meet this level of response?

A. 0.5-2.0 BCF is substantially larger than National Grid's already-aggressive Rhode Island's energy efficiency programs. 0.5 BCF is roughly equivalent to 2,500 MW. National Grid's entire load in the state is on the order of 1,400 – 1,500 MW, so an amount of load reduction necessary to displace the equivalent load served by expanded pipeline capacity is unreasonable. Even reducing the amount of incremental capacity through energy efficiency is unlikely. In the past three years, annual MW reduction has averaged 31 MW. Thus, even to reduce capacity by 10% would require eight times the average load reduction. Recognizing that the Rhode Island's programs are the most aggressive and most successful in the country, I can confidently say that there is no practical path to achieving that amount of load reduction in any period that could materially affect the identified need for additional pipeline capacity.

Q. Does this conclude your testimony?

A. Yes, it does.

Testimony of
Ann E. Leary

DIRECT TESTIMONY

OF

ANN E. LEARY

Table of Contents

I. Introduction and Qualifications

Q. Ms. Leary, please state your full name and business address.

A. My name is Ann E. Leary. My business address is 40 Sylvan Road, Waltham MA 02451.

Q. Please state your business position and responsibilities.

A. I am the Manager of New England Gas Pricing in the Regulation and Pricing department of the National Grid USA Service Company, Inc. (Service Company). My responsibilities include the design, implementation, and administration of rates and tariffs for the gas operations of The Narragansett Electric Company d/b/a National Grid (Narragansett or the Company) as well as Narragansett's gas distribution affiliates in Massachusetts, Boston Gas Company and Colonial Gas Company, each d/b/a National Grid.

Q. Please summarize your educational background and your professional experience.

A. I received a Bachelor of Science in Mechanical Engineering from Cornell University in 1983.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I have testified in several ratemaking and regulatory proceedings before the Rhode Island Public Utilities Commission (PUC), including the Company's Gas Cost Recovery (GCR) Filings, Docket Nos. 4576, 4520, 4436, and 4346. I also submitted pre-filed testimony in the Company's 2012 Rate Case Filing, Docket No. 4323. I have also testified extensively in New Hampshire and Massachusetts.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the proposed Capacity Cost Recovery Provision tariff (Proposed Tariff) for the Company's electric business which will allow the Company to recover all incremental costs associated with the procurement of gas capacity as described in the pre-filed testimony of Company witnesses Mr. Timothy Brennan and Mr. John Allocca as well as the Innovation Incentive as described in the pre-filed testimony of Company witness Mr. Michael Calviou.

Q. Could you please describe how your testimony is organized?

A. Yes. My testimony will include:

(1) a description of the Proposed Tariff, which is provided in Schedule AEL-1;

(2) a calculation of illustrative factors provided by and pursuant to the Proposed Tariff based on estimated annual levelized costs of the Company's proposal, provided in Schedule AEL-2;

(3) illustrative bill impacts resulting from the illustrative factors, premised on estimated annual levelized costs and benefits, provided in Schedule AEL-3; and

(4) illustrative winter bill impacts of the illustrative factors, premised on estimated annual levelized costs and winter levelized benefits, provided in Schedule AEL-4.

II. Proposed Tariff

Q. Could you please describe the key provisions in the Proposed Tariff?

A. Yes. The Proposed Tariff provides for the recovery of the various incremental costs the Company expects it will be incurring associated with the Proposed Agreement[1] under the structure described by Mr. Brennan and Mr. Allocca as well as an annual Innovation Incentive as described by Mr. Calviou. The Proposed Tariff[2] provides for concurrent recovery of estimated net costs through the Capacity Cost Recovery (CCR) Factor, the costs and revenue being subject to full reconciliation to actual costs and revenue, with the difference, including interest calculated at the same rate as paid on customer deposits, reflected in the Prior Period Cost Reconciliation (PPCR) Factor.

[1] Terms not defined herein are defined in the pre-filed testimony of Mr. Brennan and Mr. Allocca.

[2] The proposed Tariff is pursuant to the provisions of Rhode Island General Laws Chapter 39-31, the Affordable Clean Energy Security Act RI.

The Proposed Tariff also provides that these two proposed factors would be assessed to all retail delivery service customers based on kWh deliveries.

Q. Does the Proposed Tariff align with the provisions of Rhode Island General Laws Chapter 39-31, the Affordable Clean Energy Security Act RI ?

A. Yes, the Proposed Tariff reflects the recovery allowed pursuant to § 39-31-7 which grants the PUC the authority to approve a rate recovery mechanism for costs associated with natural gas pipeline contracts.

Q. How is the Company proposing that the incremental costs it will incur under this arrangement be recovered?

A. The Company is proposing concurrent recovery of the incremental costs, including the costs incurred directly under the contract, credits received for the release of capacity and/or sale of gas supply, the cost of a capacity manager, and incremental administrative costs, along with an Innovation Incentive, for which it is requesting PUC approval as presented in this filing. Since the underlying nature of the costs which the Company expects to incur is fixed as set forth in the Proposed Agreement and as described in the pre-filed direct testimony of Mr. Brennan and Mr. Allocca, the Company proposes to estimate the various costs and Innovation Incentive it will incur for the upcoming year. The Company will increase the total costs by the uncollectible percentage approved by the PUC in the Company's most recent electric rate case. The total estimated net costs would form the basis for a proposed CCR Factor and would

be subject to a full reconciliation of actual costs to revenue billed through the CCR Factor. The Company is proposing to accrue interest monthly on any over- or under-recovery of actual costs at the same rate as that paid on customer deposits,[3] and would submit an annual filing presenting the year's reconciliation balance and propose a factor for the recovery or refund of the reconciliation balance, which would be through the PPCR Factor.

Q. What is the Company proposing for the timing of filings which would propose the CCR Factor?

A. For the Company's first filing of a CCR Factor, the Company would propose a filing at least 45 days before any of the contracts which the PUC approves take effect, proposing a CCR Factor as defined in the Proposed Tariff. The Company would likely propose an effective date on the first day of the calendar month in which any of the contracts take effect, and the CCR Factor would be implemented for usage on and after that date.

The Company is proposing that filings proposing CCR Factors would be submitted to the PUC for its review and approval no later than November 15 of each year, proposing a CCR Factor effective the following January 1.

[3] The Company accrues interest on its over- or under-recovery balances at the customer deposit rate, which is consistent with its various reconciling mechanisms which allow for interest.

Q. What is the Company proposing for the timing of filings which would propose the PPCR Factor?

A. As the Company would prefer to align the annual changes to the PPCR Factor to coincide with the date on which many of its other reconciling factors take effect, which is April 1, the Company is proposing a calendar year reconciliation. The Company would file the reconciliation using actual costs and revenue for the calendar year at least 45 days before the proposed effective date of the PPCR Factor, which is generally around February 15, similar to most of its other reconciliations, proposing a PPCR Factor effective for the 12 months beginning April 1.

Q. Why is the Company proposing that the CCR Factor and PPCR Factor be assessed to all retail delivery service customers?

A. The Company is proposing to assess the CCR Factor and PPCR Factor from all distribution customers pursuant to Rhode Island General Laws Chapter § 39-31-5.

Q. Where will the CCR Factor and PPCR Factor appear on customers' bills?

A. The Company is proposing to include the CCR Factor and PPCR Factor on the distribution energy line on customers' bills, similar to many of its other reconciling factors.

III. Illustrative CCR Factor

Q. Is the Company presenting illustrative factors in its filing?

A. Yes it is. Schedule AEL-2 contains the calculation of illustrative CCR Factors based on the annual levelized costs of the Proposed Agreement as provided in Schedule GJW-3, (Table 8) plus a proposed Innovation Incentive proposed at 2.75 percent of total fixed contract payments, as discussed by Mr. Calviou. The Company is also presenting an estimated per-kWh reduction in electric commodity rates based on the annual levelized benefits of the Proposed Agreement on page 1 of Schedule AEL-2, which is also provided in Schedule GJW-3, (Table 8), as well as the per-kWh reduction in electric commodity prices based on the levelized benefits during only the winter months of October through March, as shown on page 2 of Schedule AEL-2.[4]

IV. Bill Impacts

Q. Is the Company providing illustrative bill impacts in this filing based upon the illustrative CCR Factor and electricity price savings?

A. The Company is providing illustrative levelized bill impacts in Schedule AEL-3 and illustrative levelized winter bill impacts in Schedule AEL-4. These bill impacts reflect

[4] The Company selected these months as they align with the pricing period of the Company's winter Standard Offer Service rates for the Residential and Commercial groups.

the levelized costs over the life of the contract[5] as well as the projected annualized and winter levelized energy savings as provided in Schedule AEL-2. The illustrative monthly bill impact for a 500 kWh residential Standard Offer Service customer is a levelized bill reduction of $7.33, or 7.8%. The illustrative winter monthly bill impact for a 500 kWh residential Standard Offer Service customer is a levelized winter bill reduction of $16.57, or 17.8%. The illustrative levelized bill impacts are based on retail delivery service rates currently in effect and a weighted average of the Standard Offer Service rates for the period April 2016 through March 2017,[6] while the illustrative winter bill impacts are based on current retail delivery service and Standard Offer Service rates for the period October 2016 through March 2017. These rates will differ when the CCR Factor is implemented, as bill impacts will reflect then-current rates.

V. Conclusion

Q. Does this conclude your pre-filed testimony in this proceeding?

A. Yes. It does.

[5] The levelized cost also includes the proposed Innovation Incentive equal to 2.75% of total fixed contract payments.

[6] The Company calculated an illustrative SOS rate for the period October 2016 through March 2017 based on the SOS supply contractrs currently executed for the period October 2016 through March 2017.

Schedule AEL-1
Proposed Tariff

R.I.P.U.C. No. 2165
Sheet 1

THE NARRAGANSETT ELECTRIC COMPANY
CAPACITY COST RECOVERY PROVISION

1. Introduction

In accordance with the provisions of Rhode Island General Laws Chapter 39-31, the Affordable Clean Energy Security Act, the prices for electric distribution service contained in all of the Company's tariffs are subject to an adjustment to reflect the costs incurred in accordance with this Capacity Cost Recovery ("CCR") Provision.

2. Definitions

CCR Factor shall mean the Capacity Cost Recovery Factor and shall be a uniform per kilowatt-hour factor based on the estimated kilowatt-hours to be delivered by the Company pursuant to § 39-31-7(5).

Commission shall mean the Rhode Island Public Utilities Commission.

Company shall mean The Narragansett Electric Company d/b/a National Grid.

3. Rate and Reconciliation Factor

$$\text{CCR Factor}_x = ((CC_x + CAPMGR_x + ADMIN_x + IN_x) \div FkWh_x) \times (1 + UP)$$

Where

x	=	The 12-month period during which the annual CCR Factor will be in effect.
CCR Factor_x	=	Capacity Cost Recovery Factor for year x.
CC_x	=	Estimated contract costs pursuant to § 39-31-7(5), which include costs under long term pipeline capacity, storage, and gas supply contracts, including inventory finance costs calculated monthly at the Company's after-tax weighted average cost of capital, as adjusted by federal income tax in effect during year x, as approved by the Commission, less estimated credits received for the release of capacity and/or sale of gas supply for year x.
$CAPMGR_x$	=	The Company's share of the estimated cost anticipated to be incurred associated with the third party management of the assets under long term gas contracts for year x pursuant to § 39-31-7(5).
$ADMIN_x$	=	Estimated incremental administrative costs associated with the administration of the long term gas contracts and consultant costs associated with the procurement of long term contracts, as approved by the Commission, for year x pursuant to § 39-31-7(5).
IN_x	=	The estimated innovation incentive associated with long term gas contracts entered into by the Company, as approved by the Commission, for year x calculated as the estimated payments under the contracts multiplied by 2.75%.
$FkWh_x$	=	The forecasted kWh deliveries for year x, defined as the forecasted amount of electricity to be delivered to the Company's retail delivery service customers.
UP	=	The uncollectible percentage approved by the Commission in the Company's most recent rate case.

The CCR Factor will be subject to reconciliation whereby actual costs incurred including costs associated with the third party management of the assets under long term contracts, innovation incentive,

THE NARRAGANSETT ELECTRIC COMPANY
CAPACITY COST RECOVERY PROVISION

and incremental administrative costs, less the revenue associated with capacity release, storage, and supply , will be compared to revenue billed through the CCR Factor for the 12-month period during which the CCR Factor is in effect, with any difference accruing interest at the rate applicable to customer deposits. The over/under-recovered balance will be recovered from all retail delivery service customers through the Past Period Cost Reconciliation ("PPCR") Factor, as defined below. The PPCR Factor shall be a uniform per kilowatt-hour factor based on the forecasted kilowatt-hours to be delivered by the Company.

$PPCR\ Factor_x = PPRA_{x-1} \div FkWh_x$

Where

$PPRA_{x-1}$ = The Past Period Reconciliation Amount defined as the ending balance of the difference between (a) the actual CC, payments made by the Company to a third party capacity manager, actual incremental administrative costs, and actual innovation incentive associated with long term contracts for year x-1 (calculated as the actual contract payments multiplied by 2.75%), as approved by the Commission for year x-1 and (b) actual revenue billed through the CCR Factor.

$FkWh_x$ = The forecasted kWh deliveries for year x, defined as the forecasted amount of electricity to be delivered to the Company's retail delivery service customers.

4. Adjustments to Rates

For billing purposes, the CCR Factor and PPCR Factor will be included with the distribution kWh charge on customers' bills.

The Company shall file its proposed CCR Factor annually, at least forty-five (45) days prior to the effective date of the proposed CCR Factor. The effective date for the annual change to the CCR Factor shall be January 1 or as otherwise approved by the Commission. The Company shall file its proposed PPCR Factor annually, at least forty-five (45) days prior to the effective date of the proposed PPCR Factor, proposing the recovery of the Past Period Reconciliation Amount. The effective date for the annual change to the PPCR Factor shall be April 1 or as otherwise approved by the Commission.

This provision is applicable to all Retail Delivery Service tariffs of the Company. The operation of this CCR Provision is pursuant to R.I.G.L. § 39-31, the Affordable Clean Energy Security Act.

Schedule AEL-2
Illustrative Calc.

The Narragansett Electric Company
d/b/a National Grid
Illustrative Capacity Cost Recovery (CCR) Factor
REDACTED DOCUMENT

		NE Levelized Costs ($) (a)	NGrid's Cost Share (b)	National Grid Levelized Costs ($)[1] (c)	Annual kWh (d)	CCR Factor $/kWh (e)
(1)	**Levelized Costs (2019-2038) ($)**	[redacted]	7.2%	[redacted]	7,648,490,366	[redacted]

		NE Levelized Benefits ($)		National Grid Levelized Benefits ($) [2]	Annual kWh	Energy Savings Factor $/kWh
(2)	**Levelized Benefits (2019-2038) ($)**	[redacted]		[redacted]	7,648,490,366	[redacted]

		NE Levelized Net Benefits($)		National Grid Levelized Net Benefits($)	Annual kWh	Net Benefit $/kWh
(3)	**Levelized Net Benefits (2019-2038) ($)**	[redacted]		[redacted]	7,648,490,366	($0.01407)

[1] Includes Innovation Incentive of 2.75% of Total Costs.

[2] Levelized Benefits based on location marginal prices in Rhode Island as described in Schedule GJW-3.

(a) See Schedule GJW-3 Table 7.
(b) Narragansett Electric's share of total contract costs and benefits. Assumes Municipalities do not share in any of the projected costs.
(c) Line 1 = Column (a) * Column (b) * 1.0275; Line 2 = Schedule GJW-3 Table 8; Line 3 = Line 1(c) + Line 2(c)
(d) Per Company forecast.
(e) Column (c) ÷ Column (d), truncated to 5 decimal places.

The Narragansett Electric Company
d/b/a National Grid
Illustrative Capacity Cost Recovery (CCR) Factor
REDACTED DOCUMENT

		NE Levelized Costs ($) (a)		NGrid's Cost Share (b)	National Grid Levelized Costs ($)[1] (c)	Annual kWh (d)	CCR Factor $/kWh (e)
(1)	**Levelized Costs (2019-2038) ($)**	[redacted]		7.2%	[redacted]	7,648,490,366	[redacted]

		NE Levelized Annualized Benefits ($) (f)	National Grid Levelized Benefits ($)[2] (g)	Winter Month Benefit (h)	National Grid Levelized Winter Benefits ($) (i)	Winter[3] kWh (j)	Winter Energy Savings Factor $/kWh (k)
(2)	**Levelized Winter Benefits (2019-2038) ($)**	[redacted]		96.0%	[redacted]	3,739,647,699	[redacted]

		Net Benefit $/kWh (l)
(3)	**Levelized Net Benefits (2019-2038) ($)**	($0.03181)

[1] Includes Innovation Incentive of 2.75% of Total Costs.
[2] Levelized Benefits based on location marginal prices in Rhode Island as described in Schedule GJW-3.
[3] Winter period defined as October through March.

(a) See Schedule GJW-3 Table 7.
(b) Narragansett Electric's share of total contract costs and benefits. Assumes Municipalities do not share in any of the projected costs.
(c) Column (a) * Column (b) * 1.0275
(d) Per Company forecast.
(e) Column (c) ÷ Column (d), truncated to 5 decimal places.
(f) See Schedule GJW-3 Table 7.
(g) See Schedule GJW-3 Table 8.
(h) See Schedule GJW-3 Footnote No. 9.
(i) Column (g) * Column (h)
(j) Per Company forecast for the months of October through March.
(k) Column (i) ÷ Column (j), truncated to 5 decimal places.
(l) Line (1) Column (e) + Line (2) Column (k)

Schedule AEL-3
Illustrative Bill Impacts

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Typical Levelized Bill Impacts
Rates A-16 and A-60 Basic Service Customers

		(a)
(1)	Capacity Cost Recovery Factor (CCRF)	[redacted]
(2)	Energy Savings Factor	
(3)	Net	($0.01407)

	Monthly kWh (b)	Current Total Bill [1] (c)	Increase (Decrease) Amount (d)	Increase (Decrease) % (e)
		Rate A-16		
(4)	150	$32.42	($2.20)	-6.8%
(5)	300	$58.69	($4.40)	-7.5%
(6)	400	$76.20	($5.86)	-7.7%
(7)	500	$93.72	($7.33)	-7.8%
(8)	600	$111.23	($8.79)	-7.9%
(9)	700	$128.75	($10.26)	-8.0%
(10)	1,200	$216.33	($17.59)	-8.1%
(11)	2,000	$356.44	($29.31)	-8.2%
		Rate A-60		
(12)	150	$25.11	($2.20)	-8.8%
(13)	300	$49.28	($4.40)	-8.9%
(14)	400	$65.38	($5.86)	-9.0%
(15)	500	$81.50	($7.33)	-9.0%
(16)	600	$97.60	($8.79)	-9.0%
(17)	700	$113.72	($10.26)	-9.0%
(18)	1,200	$194.28	($17.59)	-9.1%
(19)	2,000	$323.17	($29.31)	-9.1%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period April 2016 through March 2017.

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Typical Levelized Bill Impacts
Rate C-06 Basic Service Customers

			(a)	
(1)	Capacity Cost Recovery Factor (CCRF)		[redacted]	
(2)	Energy Savings Factor			
(3)	Net		($0.01407)	
	Monthly	Current	Increase (Decrease)	
	kWh	Total Bill [1]	Amount	%
	(b)	(c)	(d)	(e)
(4)	250	$53.59	($3.66)	-6.8%
(5)	500	$95.75	($7.33)	-7.7%
(6)	1,000	$180.04	($14.66)	-8.1%
(7)	1,500	$264.35	($21.98)	-8.3%
(8)	2,000	$348.64	($29.31)	-8.4%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period April 2016 through March 2017.

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Typical Levelized Bill Impacts
Rate G-02 Basic Service Customers

				(a)	
(1)	Capacity Cost Recovery Factor (CCRF)			[redacted]	
(2)	Energy Savings Factor				
(3)	Net			($0.01407)	
	Monthly	Monthly	Current	Increase (Decrease)	
	kW	kWh	Total Bill [1]	Amount	%
	(b)	(c)	(d)	(e)	(f)
	200 Hours Use				
(4)	20	4,000	$758.55	($58.63)	-7.7%
(5)	50	10,000	$1,767.62	($146.56)	-8.3%
(6)	100	20,000	$3,449.43	($293.13)	-8.5%
(7)	150	30,000	$5,131.23	($439.69)	-8.6%
	300 Hours Use				
(8)	20	6,000	$999.38	($87.94)	-8.8%
(9)	50	15,000	$2,369.72	($219.84)	-9.3%
(10)	100	30,000	$4,653.62	($439.69)	-9.4%
(11)	150	45,000	$6,937.52	($659.53)	-9.5%
(12)	400 Hours Use				
	20	8,000	$1,240.22	($117.25)	-9.5%
(13)	50	20,000	$2,971.82	($293.13)	-9.9%
(14)	100	40,000	$5,857.81	($586.25)	-10.0%
(15)	150	60,000	$8,743.82	($879.38)	-10.1%
	500 Hours Use				
(16)	20	10,000	$1,481.06	($146.56)	-9.9%
(17)	50	25,000	$3,573.92	($366.41)	-10.3%
(18)	100	50,000	$7,062.02	($732.81)	-10.4%
(19)	150	75,000	$10,550.11	($1,099.22)	-10.4%
	600 Hours Use				
(20)	20	12,000	$1,721.90	($175.88)	-10.2%
(21)	50	30,000	$4,176.02	($422.10)	-10.1%
(22)	100	60,000	$8,266.21	($844.20)	-10.2%
(23)	150	90,000	$12,356.41	($1,266.30)	-10.2%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period April 2016 through March 2017.

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Typical Levelized Bill Impacts
Rate G-32 Basic Service Customers

				(a)	
(1)	Capacity Cost Recovery Factor (CCRF)			[redacted]	
(2)	Energy Savings Factor				
(3)	Net			($0.01407)	
	Monthly	Monthly	Current	Increase (Decrease)	
	kW	kWh	Total Bill [1]	Amount	%
	(b)	(c)	(d)	(e)	(f)
	200 Hours Use				
(4)	200	40,000	$6,043.63	($586.25)	-9.7%
(5)	750	150,000	$22,791.03	($2,198.44)	-9.6%
(6)	1,000	200,000	$30,403.49	($2,931.25)	-9.6%
(7)	1,500	300,000	$45,628.40	($4,396.88)	-9.6%
(8)	2,500	500,000	$76,078.23	($7,328.13)	-9.6%
	300 Hours Use				
(9)	200	60,000	$8,212.56	($879.38)	-10.7%
(10)	750	225,000	$30,924.56	($3,297.66)	-10.7%
(11)	1,000	300,000	$41,248.19	($4,396.88)	-10.7%
(12)	1,500	450,000	$61,895.45	($6,595.31)	-10.7%
(13)	2,500	750,000	$103,189.99	($10,992.19)	-10.7%
	400 Hours Use				
(14)	200	80,000	$10,381.50	($1,172.50)	-11.3%
(15)	750	300,000	$39,058.08	($4,396.88)	-11.3%
(16)	1,000	400,000	$52,092.89	($5,862.50)	-11.3%
(17)	1,500	600,000	$78,162.51	($8,793.75)	-11.3%
(18)	2,500	1,000,000	$130,301.74	($14,656.25)	-11.2%
	500 Hours Use				
(19)	200	100,000	$12,550.44	($1,465.63)	-11.7%
(20)	750	375,000	$47,191.61	($5,496.09)	-11.6%
(21)	1,000	500,000	$62,937.60	($7,328.13)	-11.6%
(22)	1,500	750,000	$94,429.57	($10,992.19)	-11.6%
(23)	2,500	1,250,000	$157,413.50	($18,320.31)	-11.6%
	600 Hours Use				
(24)	200	120,000	$14,719.39	($1,758.75)	-11.9%
(25)	750	450,000	$55,325.14	($6,595.31)	-11.9%
(26)	1,000	600,000	$73,782.30	($8,793.75)	-11.9%
(27)	1,500	900,000	$110,696.63	($13,190.63)	-11.9%
(28)	2,500	1,500,000	$184,525.27	($21,984.38)	-11.9%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period July 2015 through June 2016.

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Typical Levelized Bill Impacts
Rate G-62 Basic Service Customers

				(a)	
(1)	Capacity Cost Recovery Factor (CCRF)			[redacted]	
(2)	Energy Savings Factor				
(3)	Net			($0.01407)	
	Monthly	Monthly	Current	Increase (Decrease)	
	kW	kWh	Total Bill [1]	Amount	%
	(b)	(c)	(d)	(e)	(f)
	200 Hours Use				
(4)	3,000	600,000	$103,288.86	($8,793.75)	-8.5%
(5)	5,000	1,000,000	$160,101.01	($14,656.25)	-9.2%
(6)	7,500	1,500,000	$231,116.20	($21,984.38)	-9.5%
(7)	10,000	2,000,000	$302,131.39	($29,312.50)	-9.7%
(8)	20,000	4,000,000	$586,192.16	($58,625.00)	-10.0%
	300 Hours Use				
(9)	3,000	900,000	$134,913.60	($13,190.63)	-9.8%
(10)	5,000	1,500,000	$212,808.91	($21,984.38)	-10.3%
(11)	7,500	2,250,000	$310,178.05	($32,976.56)	-10.6%
(12)	10,000	3,000,000	$407,547.19	($43,968.75)	-10.8%
(13)	20,000	6,000,000	$797,023.75	($87,937.50)	-11.0%
	400 Hours Use				
(14)	3,000	1,200,000	$166,538.34	($17,587.50)	-10.6%
(15)	5,000	2,000,000	$265,516.80	($29,312.50)	-11.0%
(16)	7,500	3,000,000	$389,239.90	($43,968.75)	-11.3%
(17)	10,000	4,000,000	$512,962.99	($58,625.00)	-11.4%
(18)	20,000	8,000,000	$1,007,855.35	($117,250.00)	-11.6%
	500 Hours Use				
(19)	3,000	1,500,000	$198,163.08	($21,984.38)	-11.1%
(20)	5,000	2,500,000	$318,224.71	($36,640.63)	-11.5%
(21)	7,500	3,750,000	$468,301.74	($54,960.94)	-11.7%
(22)	10,000	5,000,000	$618,378.79	($73,281.25)	-11.9%
(23)	20,000	10,000,000	$1,218,686.95	($146,562.50)	-12.0%
	600 Hours Use				
(24)	3,000	1,800,000	$229,787.82	($26,381.25)	-11.5%
(25)	5,000	3,000,000	$370,932.61	($43,968.75)	-11.9%
(26)	7,500	4,500,000	$547,363.59	($65,953.13)	-12.0%
(27)	10,000	6,000,000	$723,794.58	($87,937.50)	-12.1%
(28)	20,000	12,000,000	$1,429,518.54	($175,875.00)	-12.3%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period July 2015 through June 2016.

Schedule AEL-4
Illustratrative Winter Bill Impacts

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Winter Typical Levelized Bill Impacts
Rates A-16 and A-60 Basic Service Customers

		(a)
(1)	Capacity Cost Recovery Factor (CCRF)	[redacted]
(2)	Energy Savings Factor	
(3)	Net	($0.03181)

	Monthly kWh (b)	Current Total Bill [1] (c)	Increase (Decrease) Amount (d)	Increase (Decrease) % (e)
		Rate A-16		
(4)	150	$32.17	($4.97)	-15.4%
(5)	300	$58.20	($9.94)	-17.1%
(6)	400	$75.55	($13.25)	-17.5%
(7)	500	$92.90	($16.57)	-17.8%
(8)	600	$110.25	($19.88)	-18.0%
(9)	700	$127.60	($23.19)	-18.2%
(10)	1,200	$214.36	($39.76)	-18.5%
(11)	2,000	$353.17	($66.27)	-18.8%
		Rate A-60		
(12)	150	$24.86	($4.97)	-20.0%
(13)	300	$48.79	($9.94)	-20.4%
(14)	400	$64.73	($13.25)	-20.5%
(15)	500	$80.68	($16.57)	-20.5%
(16)	600	$96.62	($19.88)	-20.6%
(17)	700	$112.57	($23.19)	-20.6%
(18)	1,200	$192.31	($39.76)	-20.7%
(19)	2,000	$319.90	($66.27)	-20.7%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period October 2016 through March 2017.

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Winter Typical Levelized Bill Impacts
Rate C-06 Basic Service Customers

		(a)
(1)	Capacity Cost Recovery Factor (CCRF)	[redacted]
(2)	Energy Savings Factor	
(3)	Net	($0.03181)

	Monthly kWh (b)	Current Total Bill [1] (c)	Increase (Decrease) Amount (d)	Increase (Decrease) % (e)
(4)	250	$53.90	($8.28)	-15.4%
(5)	500	$96.35	($16.57)	-17.2%
(6)	1,000	$181.26	($33.14)	-18.3%
(7)	1,500	$266.17	($49.70)	-18.7%
(8)	2,000	$351.07	($66.27)	-18.9%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period October 2016 through March 2017.

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Winter Typical Levelized Bill Impacts
Rate G-02 Basic Service Customers

				(a)	
(1)	Capacity Cost Recovery Factor (CCRF)			[redacted]	
(2)	Energy Savings Factor				
(3)	Net			($0.03181)	
	Monthly	Monthly	Current	Increase (Decrease)	
	kW	kWh	Total Bill [1]	Amount	%
	(b)	(c)	(d)	(e)	(f)
	200 Hours Use				
(4)	20	4,000	$763.41	($132.54)	-17.4%
(5)	50	10,000	$1,779.78	($331.35)	-18.6%
(6)	100	20,000	$3,473.74	($662.71)	-19.1%
(7)	150	30,000	$5,167.70	($994.06)	-19.2%
	300 Hours Use				
(8)	20	6,000	$1,006.67	($198.81)	-19.7%
(9)	50	15,000	$2,387.96	($497.03)	-20.8%
(10)	100	30,000	$4,690.09	($994.06)	-21.2%
(11)	150	45,000	$6,992.23	($1,491.09)	-21.3%
	400 Hours Use				
(12)	20	8,000	$1,249.95	($265.08)	-21.2%
(13)	50	20,000	$2,996.13	($662.71)	-22.1%
(14)	100	40,000	$5,906.44	($1,325.42)	-22.4%
(15)	150	60,000	$8,816.77	($1,988.13)	-22.5%
	500 Hours Use				
(16)	20	10,000	$1,493.22	($331.35)	-22.2%
(17)	50	25,000	$3,604.32	($828.39)	-23.0%
(18)	100	50,000	$7,122.80	($1,656.77)	-23.3%
(19)	150	75,000	$10,641.29	($2,485.16)	-23.4%
	600 Hours Use				
(20)	20	12,000	$1,736.49	($397.63)	-22.9%
(21)	50	30,000	$4,212.49	($954.30)	-22.7%
(22)	100	60,000	$8,339.16	($1,908.60)	-22.9%
(23)	150	90,000	$12,465.83	($2,862.90)	-23.0%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period October 2016 through March 2017.

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Winter Typical Levelized Bill Impacts
Rate G-32 Basic Service Customers

				(a)	
(1)	Capacity Cost Recovery Factor (CCRF)			[redacted]	
(2)	Energy Savings Factor				
(3)	Net			($0.03181)	
	Monthly	Monthly	Current	Increase (Decrease)	
	kW	kWh	Total Bill [1]	Amount	%
	(b)	(c)	(d)	(e)	(f)
	200 Hours Use				
(4)	200	40,000	$6,771.99	($1,325.42)	-19.6%
(5)	750	150,000	$25,522.41	($4,970.31)	-19.5%
(6)	1,000	200,000	$34,045.33	($6,627.08)	-19.5%
(7)	1,500	300,000	$51,091.16	($9,940.63)	-19.5%
(8)	2,500	500,000	$85,182.83	($16,567.71)	-19.4%
	300 Hours Use				
(9)	200	60,000	$9,305.11	($1,988.13)	-21.4%
(10)	750	225,000	$35,021.63	($7,455.47)	-21.3%
(11)	1,000	300,000	$46,710.95	($9,940.63)	-21.3%
(12)	1,500	450,000	$70,089.59	($14,910.94)	-21.3%
(13)	2,500	750,000	$116,846.89	($24,851.56)	-21.3%
	400 Hours Use				
(14)	200	80,000	$11,838.24	($2,650.83)	-22.4%
(15)	750	300,000	$44,520.84	($9,940.63)	-22.3%
(16)	1,000	400,000	$59,376.57	($13,254.17)	-22.3%
(17)	1,500	600,000	$89,088.03	($19,881.25)	-22.3%
(18)	2,500	1,000,000	$148,510.94	($33,135.42)	-22.3%
	500 Hours Use				
(19)	200	100,000	$14,371.36	($3,313.54)	-23.1%
(20)	750	375,000	$54,020.06	($12,425.78)	-23.0%
(21)	1,000	500,000	$72,042.20	($16,567.71)	-23.0%
(22)	1,500	750,000	$108,086.47	($24,851.56)	-23.0%
(23)	2,500	1,250,000	$180,175.01	($41,419.27)	-23.0%
	600 Hours Use				
(24)	200	120,000	$16,904.49	($3,976.25)	-23.5%
(25)	750	450,000	$63,519.28	($14,910.94)	-23.5%
(26)	1,000	600,000	$84,707.82	($19,881.25)	-23.5%
(27)	1,500	900,000	$127,084.91	($29,821.88)	-23.5%
(28)	2,500	1,500,000	$211,839.07	($49,703.13)	-23.5%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period October 2016 through March 2017.

REDACTED DOCUMENT

The Narragansett Electric Company
Capacity Cost Recovery - Illustrative Winter Typical Levelized Bill Impacts
Rate G-62 Basic Service Customers

				(a)	
(1)	Capacity Cost Recovery Factor (CCRF)			[redacted]	
(2)	Energy Savings Factor				
(3)	Net			($0.03181)	
	Monthly	Monthly	Current	Increase (Decrease)	
	kW	kWh	Total Bill [1]	Amount	%
	(b)	(c)	(d)	(e)	(f)
	200 Hours Use				
(4)	3,000	600,000	$114,214.38	($19,881.25)	-17.4%
(5)	5,000	1,000,000	$178,310.21	($33,135.42)	-18.6%
(6)	7,500	1,500,000	$258,430.00	($49,703.13)	-19.2%
(7)	10,000	2,000,000	$338,549.80	($66,270.83)	-19.6%
(8)	20,000	4,000,000	$659,028.96	($132,541.67)	-20.1%
	300 Hours Use				
(9)	3,000	900,000	$151,301.88	($29,821.88)	-19.7%
(10)	5,000	1,500,000	$240,122.71	($49,703.13)	-20.7%
(11)	7,500	2,250,000	$351,148.75	($74,554.69)	-21.2%
(12)	10,000	3,000,000	$462,174.79	($99,406.25)	-21.5%
(13)	20,000	6,000,000	$906,278.96	($198,812.50)	-21.9%
	400 Hours Use				
(14)	3,000	1,200,000	$188,389.38	($39,762.50)	-21.1%
(15)	5,000	2,000,000	$301,935.21	($66,270.83)	-21.9%
(16)	7,500	3,000,000	$443,867.50	($99,406.25)	-22.4%
(17)	10,000	4,000,000	$585,799.79	($132,541.67)	-22.6%
(18)	20,000	8,000,000	$1,153,528.96	($265,083.33)	-23.0%
	500 Hours Use				
(19)	3,000	1,500,000	$225,476.88	($49,703.13)	-22.0%
(20)	5,000	2,500,000	$363,747.71	($82,838.54)	-22.8%
(21)	7,500	3,750,000	$536,586.25	($124,257.81)	-23.2%
(22)	10,000	5,000,000	$709,424.80	($165,677.08)	-23.4%
(23)	20,000	10,000,000	$1,400,778.96	($331,354.17)	-23.7%
	600 Hours Use				
(24)	3,000	1,800,000	$262,564.38	($59,643.75)	-22.7%
(25)	5,000	3,000,000	$425,560.21	($99,406.25)	-23.4%
(26)	7,500	4,500,000	$629,305.00	($149,109.38)	-23.7%
(27)	10,000	6,000,000	$833,049.79	($198,812.50)	-23.9%
(28)	20,000	12,000,000	$1,648,028.96	($397,625.00)	-24.1%

[1]Current Bill reflects current delivery service rates, and annualized Standard Offer Service Rate based on the period October 2016 through March 2017.