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September 12, 2016

BY HAND DELIVERY

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

Re: Docket 4627 – In Re: Request for Approval of Firm Transportation Contracts with Algonquin Gas Transmission, LLC for the Access Northeast Project
Responses to McKee Data Requests – Set 1

Dear Ms. Massaro:

On behalf of National Grid,[1] enclosed are National Grid's responses to the First Set of Data Requests issued by Lt. Governor McKee in the above-referenced matter. Please note that the responses to Data Requests McKee-Grid-1-11, McKee-Grid-1-13, specifically Attachment McKee-Grid-1-13, McKee-Grid-1-28 and McKee-Grid-1-32 contain Highly Sensitive Confidential Information. A Motion for Protective Treatment is enclosed and the confidential version of these responses will only be provided to the Public Utilities Commission and those parties that have executed the appropriate non-disclosure agreement.

Thank you for your attention to matter. If you have any questions, please contact me at (617) 951-1400, or Jennifer Brooks Hutchinson at 401-784-7685.

Very truly yours,

John K. Habib

John K. Habib

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

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. 4627**

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 filed 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 submitted 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 provided by

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

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

On September 12, 2016 National Grid filed its responses to the Lt. Governor McKee's (McKee) First Set of Data Requests that reference these highly sensitive confidential terms. Specifically, the Company is seeking protective treatment of its response to Data Requests McKee-Grid-1-11, McKee-Grid-1-13, specifically Attachment McKee-Grid-1-13, McKee-Grid-1-28 and McKee-Grid-1-32 (the HSCI Documents).

As noted above, 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 Department. 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.

In this proceeding, the Company proposed 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 have been classified as either Confidential or Highly Sensitive Confidential Information, consistent with the Company's initial filing and as filed in Massachusetts. Although the PUC has declined to adopt the two-tier method of protective treatment proposed, the PUC has determined that National Grid can still mark documents as either HSCI or Confidential and enter into non-disclosure agreements appropriate for each classification.

The Company has provided redacted and unredacted versions of each of the HSCI 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 HSCI Documents protective 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 HSCI Documents includes confidential and proprietary bidder information, pricing information, and confidential contractual terms including pricing information that was negotiated by the

Company with Algonquin. This information includes information that was obtained from bidders under a confidentiality agreement and contains their confidential pricing data. 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.

The HSCI Documents also contain information and outputs that flow from proprietary modeling systems that are the property of the Company's consultant, Black & Veatch. These models, including the assumptions, and the outputs resulting from the models were developed by Black & Veatch for its use in providing analytical and other services to its business clients, including the Company. The models are not available in the public domain, nor may the public access the models, inputs or outputs absent a binding contract for services with Black & Veatch. If publicly disclosed, these documents would provide competitively sensitive information to other parties and could seriously harm the competitive business position of Black & Veatch. Such a result would be contrary to the public interest.

IV. CONCLUSION

Accordingly, the Company requests that the PUC grant protective treatment to the Company's response to Data Requests McKee-Grid-1-11, McKee-Grid-1-13, specifically Attachment McKee-Grid-1-13, McKee-Grid-1-28 and McKee-Grid-1-32.

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

Respectfully submitted,

NATIONAL GRID

By its attorneys,

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Dated: September 12, 2016

McKEE-GRID 1-1

Request:

Are we the ratepayers buying this capacity for a fair price from the ANE project sponsors? How do we know?

Response:

Yes, the price negotiated by the Company on behalf of its customers is a fair price. The rate mechanism set forth in the agreement was the result of arms-length negotiations between the Company and Algonquin that took place over many months leading up to execution of the agreement. The rate is cost-based and includes an adjustment mechanism that will result in a reduced rate in the event that the actual cost of the project is less than the expected cost. The mechanism also includes an absolute rate cap that protects the customers from project costs that exceed the estimated cost beyond the negotiated maximum. The negotiated rate agreement also contains a most-favored-nation provision that provides protection to customers in the event that Algonquin offers similar capacity to future customers at a lower rate. The rate is consistent with other similar projects that have been proposed in recent years and the rate was attractive when compared to other projects that were proposed in response to the Company's October 23, 2015 Request for Proposals..

McKEE-GRID 1-2

Request:

In this proposal before the PUC as docket 4627, National Grid is proposing that the Company and its electric distribution ratepayers go into business together. We will be entering into commitments to purchase a given amount of certain natural gas products for a twenty-year period for resale, primarily to electric generators. The products include pipeline capacity, LNG services, and gas storage capacity.

A. Once the Access Northeast project is completed, we will be committing to purchase certain amounts of these products at a guaranteed price to Algonquin. However, it appears from this filing by National Grid that we have obtained no such volume or price commitments from our customers, namely the electric generators. Is this correct?

B. Which partner, National Grid or its electric distribution ratepayers, will bear the volume risk of this venture (the risk that hoped-for purchases of our products does not materialize at the levels we need)?

C. Which partner will bear the price risk (the risk that we cannot get the price we expect for the products we are offering to the electric generation market)?

D. There are other providers today of gas pipeline capacity and LNG services to the New England market. Are they in business to make a profit? Their continued existence in this business strongly suggests that it is typical for such entities to receive revenues from the sale of gas capacity and services that are greater than their costs. Explain why National Grid's electric ratepayers should not have the same expectation from our investment in the Access Northeast project.

Response:

The opening premise of this question—i.e., that "National Grid is proposing that the Company and its electric distribution ratepayers go into business together" to purchase natural gas products "for resale, primarily to electric generators"—misstates and mischaracterizes the Company's proposal before the PUC.

The Company is not proposing to enter into a business venture with its customers with the goal of profitably reselling pipeline capacity, LNG services, and gas storage capacity on Access

Northeast. Rather, the Company has submitted the Proposed Agreement for approval by the PUC as an innovative solution to a market failure. As explained in the Testimony of Gary J. Wilmes from Black & Veatch Corporation, the Proposed Agreement is projected to yield direct levelized net economic benefits to New England electricity customers of $1.1 billion per year over the life of the contract (see Table 7 in Schedule GJW-3), with levelized net benefits of approximately $110 million per year for RI electricity customers (see Table 8 in Schedule GJW-3). The aforementioned net benefits do not assume any revenue at all from resale of the Access Northeast capacity. That is, the Company's economic benefit-cost analysis prepared by Black & Veatch Corporation demonstrates substantial net economics benefits for Rhode Island customers even before taking into account the anticipated revenue from resale of the Access Northeast capacity to electricity generators. The Proposed Agreement yields these net benefits because Access Northeast relieves the winter-time natural gas capacity shortage that has led to high and volatile electricity prices in New England. The resale value of the Access Northeast capacity is not what drives the value to customers of the Proposed Agreement. In addition to improved reliability, the value to customers comes from the lower wholesale electricity prices and thus electricity commodity cost savings that the Company has demonstrated will result from the Proposed Agreement.

A. Please see the Company's response to data request McKEE-GRID 1-27.

B. As explained above, there is no risk to the Company's customers related to the amount of capacity release revenue realized from the Proposed Agreement because the economic benefit-cost analysis demonstrates substantial net benefits (see Schedule GJW-3) without assuming any revenue to offset the contract costs. Moreover, the benefit-cost analysis in Schedule GJW-3 shows that the finding of net economic benefits for customers from the Proposed Agreement is robust to a range of scenarios.

C. Similarly, there is no price risk to the Company's customers related to the price of capacity released to electricity generators because the economic benefit-cost analysis demonstrates substantial net benefits (see Schedule GJW-3) without assuming any revenue to offset the contract costs. The benefit-cost analysis in Schedule GJW-3 shows that the finding of net economic benefits for customers from the Proposed Agreement is robust to a range of scenarios.

D. As further discussed below, the purpose of the Proposed Agreement is not to deliver a "profit" to customers in the form of revenue from resale of Access Northeast capacity that exceeds the cost of the Proposed Agreement. Rather, the demonstrated economic value of the Proposed Agreement for the Company's customers comes from the electricity commodity cost savings from lower wholesale electricity prices. Those lower electricity prices result from ameliorating the winter-time natural gas capacity constraint in New England. The value from capacity release revenue that is not accounted for in the Company's benefit-cost analysis would accrue to the benefit of customers over and above the projected net benefits for customers projected in Schedule GJW-3. Multiple studies have demonstrated a need for new natural gas transportation capacity and documented the excessive electricity costs suffered by New England customers in recent winters owing to constrained natural gas transportation capacity (see, e.g., Joint Testimony of Timothy J. Brennan and John E. Allocca, at 16-21). However, because natural gas pipeline companies are "in business to make a profit" they require long-term commitments before they will invest in new capacity. Electricity generators are similarly "in business to make a profit" and lack the market incentives to make such long-term commitments. As such, despite ample evidence that New England needs new natural gas transportation capacity, without the efforts of the New England electricity distribution companies (EDCs) to further an innovative approach to solve this market failure by serving as counterparties to long-term contracts for incremental natural gas capacity, the net economic benefits to electricity customers from new natural gas capacity would go unrealized. As the Massachusetts Department of Energy Resources explained:

> Local gas distribution companies contract for gas capacity to serve their thermal load and receive assurance of cost recovery in their rates. However, generators with gas-fired power plants who sell into an unregulated power market are generally unwilling or unable to take similar steps to secure firm gas capacity. For these generators, there is added risk for such contracting because there is no means by which they can be reasonably assured of receiving enough revenue to cover the cost over the course of each year. Pipelines also are not willing to build new capacity without having long-term contracts in place. Hence, there has been insufficient assurance for pipeline companies to take the steps necessary to build capacity for natural gas-fired electric generators, despite the increasing natural gas demand for heating and as a source of supply for electric power in Massachusetts and New England. The mismatch between the availability of long-term commitments needed to stimulate necessary gas pipeline expansion and the willingness and/or ability of gas-fired generators to supply

> those commitments is the essential problem that is in need of a solution.[1]

[1] Massachusetts Department of Energy Resources Initial Filing in D.P.U. 15-37, Re: Request to Open an Investigation into New, Incremental Natural Gas Delivery Capacity for Thermal Load and Electric Generation (April 2, 2015).

McKEE-GRID 1-3

Request:

What level of benefits (in the form of lower future electric commodity costs) is National Grid willing to guarantee to its electric distribution ratepayers? How will those savings be measured and documented?

Response:

The Company has not proposed to guarantee a certain level of benefits in the form of lower future electric commodity costs for its electric distribution customers.

The economic benefit-cost analysis presented in Schedule GJW-3 projects that the Proposed Agreement will deliver substantial net benefits to Rhode Island electricity customers under a range of scenarios, including substantial incremental clean energy generation over and above regional renewable portfolio standard targets. Moreover, the net economic benefits from lower future electric commodity costs presented by the Company in this proceeding are corroborated by the independent benefit-cost analysis of Access Northeast undertaken by ICF International on behalf of Eversource Energy in D.P.U. 15-181 before the Massachusetts Department of Public Utilities (see, e.g., Exhibit EVER-KRP-3 in that proceeding. A copy of this exhibit is provided as Attachment McKee-GRID-1-3)

The arguments of certain parties opposed to the New England electric distribution companies' pursuit of contracts for incremental natural gas capacity themselves support the Company's analysis showing substantial electric commodity cost savings for customers. Specifically, in filing a Section 206 complaint before the Federal Energy Regulatory Commission (FERC) against ISO-NE, NextEra Energy Resources, LLC, and PSEG Companies based their complaint on the fact that the Access Northeast project would have the effect of "suppressing gas prices and wholesale power prices."[1]

[1] Complaint and Request for Fast Track Processing, FERC Docket No. EL16-93 (June 24, 2016).

Access Northeast Project - Reliability Benefits and Energy Cost Savings to New England Consumers

Prepared for

NSTAR Electric Company
Western Massachusetts Electric Company
Public Service Company of NH
Connecticut Light and Power Company
Each d/b/a Eversource Energy (Eversource)

Prepared by

ICF International
9300 Lee Highway
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December 18, 2015

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Executive Summary

ICF International (ICF) was engaged by Eversource to provide an independent assessment of the potential impacts of the proposed Access Northeast gas infrastructure project (Access Northeast) on New England's natural gas and electric markets. In particular, ICF's analysis focuses on the impact that new infrastructure may have on regional gas and electricity prices, and the associated economic impacts on consumers.

New England has been steadily increasing its reliance on natural gas-fired electricity generation over the past fifteen years. Currently, about 50% of New England's power comes from gas-fired generation, compared to roughly 15%[1] in 2000. Furthermore, the projected retirements of regional nuclear and coal-fired power plants is expected to result in the construction of new gas-fired generation.

Many observers, including the ISO-NE and ICF, have noted that New England faces the risk of persistent and growing natural gas supply constraints without any new sources of capacity. Of particular concern is whether the network of gas production, pipelines, and storage capacity serving New England will be adequate to supply power generators under winter gas demand conditions.[2] A 2014 ICF study for ISO-NE indicates a need for up to 1.1 Bcf/d of additional gas supply by 2020 to meet projected power plant fuel requirements on a design day.[3] This equates to roughly 5,700 MW[4] of capacity, or up to approximately 30% of the region's gas generation capacity. Without changes to the current structure of the regional energy markets, such risks could disproportionately affect electricity markets, and thereby negatively affect economic and potential service reliability for all New England consumers.

Access Northeast could significantly enhance ISO-NE's electric system reliability by directly providing firm natural gas fuel for gas fired power generators and help New England potentially avoid costly load shedding measures under extreme circumstances.

ICF's analysis suggests that Access Northeast would generate significant cost savings to New England electric consumers by reducing the price of natural gas delivered to New England utilities and subsequently, wholesale energy prices in all New England states. ICF estimates that on average, under normal weather conditions, Access Northeast would save New England electric consumers $1.4 to $1.9 billion per year[5] and under design winter conditions[6] with a nuclear outage, $3.1 billion per year, as detailed in Table 1. About 80% of the benefits accrue to consumers in Massachusetts, Connecticut and New Hampshire.

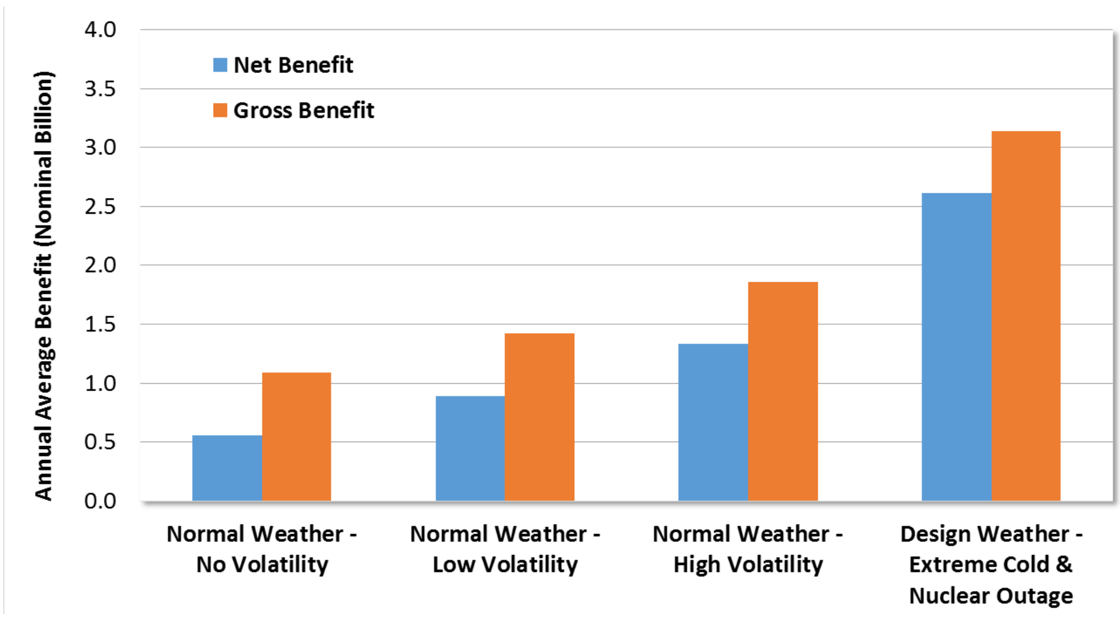
[1] http://www.iso-ne.com/static-assets/documents/2015/03/icf_isone_van_welie.pdf slide 7.
[2] New England residential and commercial demand is the highest during the peak winter months of December, January and February and LDCs will draw heavily on existing natural gas infrastructure.
[3] Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II, page 21, Exhibit 4-6.
[4] Ibid.
[5] The cost savings discussed throughout this report do not include potential revenues from capacity released into the market.
[6] Design winter conditions are dependent on how companies define it, but it is generally a very cold winter with a coldest day, based on observed weather over the last 20-30 years.

Table 1: Annual Access Northeast Benefits and Cost Summary (Average of 2019-2035)

	New England (Nominal Billion)	MA (Nominal Million)	CT (Nominal Million)	NH (Nominal Million)
Normal Weather (Low Volatility)	$1.4	$630	$370	$140
Normal Weather (High Volatility)	$1.9	$830	$480	$185
Design Weather (2021-2022)	$3.1	$1,390	$780	$270
Costs[7]	$0.5	TBD	TBD	TBD
Net Benefits (Low-High Volatility)	$0.9 - $1.3	--	--	--

Source: ICF

Figure 1: Annual Average Gross and Net Benefits for New England under Different Scenarios



Source: ICF

Key observations and conclusions are summarized below.

Outlook for New England Gas Market

New England needs incremental firm natural gas supplies for the electric sector during winter months due to increasing gas consumption for power generation

[7] Estimated demand charge to be paid by New England EDCs for Access Northeast capacity, provided by Eversource.

In recent years, New England has steadily increased its reliance on natural gas fired generation as coal and nuclear power plants have been retired. This growing reliance on natural gas is expected to continue during the next few years with the retirement of additional nuclear, coal, and oil-fired capacity (e.g., Vermont Yankee, Brayton Point, Mount Tom, and Pilgrim) and the addition of new gas-fired capacity (Footprint Power). Cumulative firm retirements of nuclear, coal and older oil/gas units in New England are expected to reach 4,151 MW by 2019.[8] In the future, the New England electricity market will be increasingly served by a combination of natural gas, renewable and energy efficiency sources. ICF projections assume that all states will achieve their stated Renewable Portfolio Standards ("RPS") targets on schedule.[9] Growth in electric load will be partially offset by energy efficiency and passive demand response gains, reducing projected growth in net energy load to only 0.04% per year through 2035. Notwithstanding these increases in renewables and energy efficiency, ICF projects that the region will require approximately 1,740 MW of new gas-fired generating capacity by 2019, further increasing power sector gas demand. As a result, the demand for natural gas from the power sector has increased, with the growth rates being greatest in the winter heating season when traditional heating demand for natural gas is also at its peak.

<u>Diminishing New England gas supply sources increase consumer exposure to non-firm gas supplies</u>

Historically, a portion of New England's gas supplies have come from gas fields in offshore Atlantic Canada and liquefied natural gas (LNG) cargoes delivered to regional import terminals. Both of these supply sources have diminished in recent years, which will require New England to replace these sources simply to preserve the supply/demand status quo.

The Maritimes and Northeast (M&N) Pipeline was originally constructed to bring Sable Island offshore gas production to markets in Eastern Canada and New England. However, the development of Sable Island production was less than originally anticipated, and production from that field has been declining since 2008.[10] A second offshore field, Deep Panuke, began production in October 2013. At its peak, Deep Panuke was expected to produce about 300 MMcf/d, but there have been numerous technical problems that have intermittently halted production, and over the past year production has averaged less than 100 MMcf/d.[11]

New England's access to gas supplies has become further constrained by the reduced frequency of firm cargoes at the regions' LNG import terminals. LNG is a global commodity and importers to New England largely operate without firm contracts to sell to New England buyers, instead preferring to seek the highest prices available wherever that may be. The Canaport LNG import terminal in New Brunswick has also provided gas supplies to New England. In 2013, Repsol S.A., the majority owner and manager of the

[8] Retirements considered firm if they are permanently delisted units or if they have submitted a non-price retirement request that ISO-NE has accepted.
[9] The implications for generating sources under the recently announced and revised Clean Power Plan are still being assessed.
[10] http://www.cnsopb.ns.ca/sites/default/files/pdfs/monthly_production_plots.pdf
[11] http://www.cnsopb.ns.ca/sites/default/files/pdfs/dp_monthly_prodution_plot.pdf

Canaport terminal, sold its long-term LNG supply contracts and ship charters, leaving Canaport with minimal firm supply contracts. LNG imports also come directly into New England via the Everett terminal. Imports to Everett declined by 81% from 2011 to 2014.[12] There are two other offshore LNG import terminals that connect into New England, Neptune and Northeast Gateway. Over the 7 years from 2008 and 2014, the offshore terminals received a total of only 45 Bcf, and Neptune has received no shipments since it initial commissioning in 2010.[13] ICF assumes that LNG imports at Canaport and Everett remain at 2014-2015 winter levels throughout the forecast period based on current firm LNG contracts.

New England would benefit from greater access to the growing production in the Marcellus/Utica basins

The Appalachian Basin was one of the first US oil and gas producing regions, and ICF expects that the Appalachian Basin's role as supplier will continue to grow as production from the Marcellus/Utica shale region increases from its current output of 18 Bcf/d[14] to a projected 42 Bcf/d by 2035. The dramatic increase in low-cost Appalachian Basin gas production has materially altered the relationship of the basin's gas prices to other trading points across the North American market. The price of natural gas in the Appalachian Basin (represented by the Dominion South pricing point) relative to the North American benchmark Henry Hub (Louisiana) price has plummeted nearly $1.50/MMbtu from a premium to a discount of more than $1.00. ICF projections show that, as a result of declining production costs, the discounted spread will widen further to nearly $2.00/MMBtu. At these prices, the Appalachian Basin is among the lowest priced gas supply sources on the continent, and this gas supply is located very close geographically to New England.

Electric Market Benefits from Access Northeast

Access Northeast would significantly reduce the wholesale power costs in New England by reducing congestion and prices for New England's natural gas market.

In a normal weather year, Access Northeast would save New England electric consumers $1.4 billion to $1.9 billion per year

ICF estimates that, on average, Access Northeast would save New England electric consumers $1.4 billion to $1.9 billion per year over the period of 2019 to 2035. For context, ISO-NE reported that "the total value of the region's wholesale electricity markets, including electric energy, capacity, and ancillary services markets, rose…to about $9.9 billion in 2014 … [and electric] energy comprised $8.4 billion of the

[12] U.S. Energy Information Administration, U.S. Natural Gas Imports by Point of Entry, http://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm, accessed October 28, 2015.
[13] U.S. Energy Information Administration, Ibid.
[14] 18 Bcf/d is dry gas output from the Marcellus/Utica basins alone. It does not include any liquids production and conventional production in the Appalachian region. "Wet" gas and conventional production from the area pushes the total above 20 Bcfd.

total."[15] The potential cost savings stem from the highly correlated nature of natural gas prices and wholesale power prices in New England, and the fact that lower gas prices resulting from Access Northeast capacity reduce wholesale power prices. These savings would ultimately extend to all New England electric consumers, including those in the states not directly receiving natural gas from the Access Northeast project.

Under design winter weather conditions and a nuclear outage, Access Northeast would save New England electric consumers $2.6 billion over a five month winter period

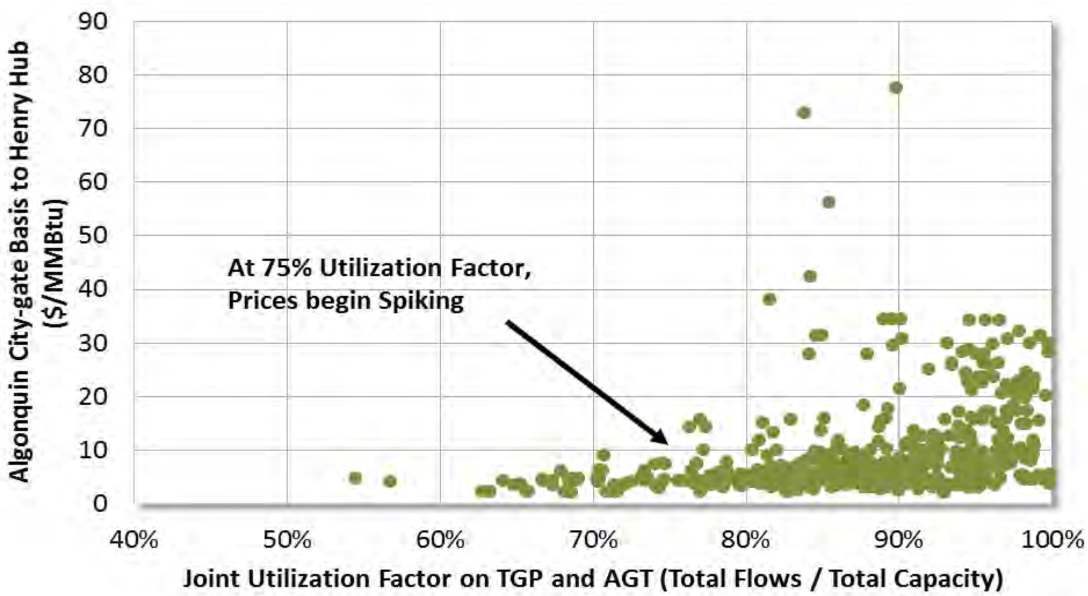
The consequences of New England's growing dependence on non-firm pipeline capacity for gas-fired generation were made clear in the 2013-2014 winter. During the Polar Vortex episodes, power generation and heating demand for natural gas soared in the Midwest, Northeast, and Mid-Atlantic. Assuming design winter cold conditions, as well as a potential nuclear outage during the winter and higher power demand (ISO-NE's P90 demand forecast), ICF estimates that with Access Northeast, electric consumers would save $2.6 billion between November 2021 and March 2022, which on an annualized basis would be $3.1 billion.

New England wholesale gas and electric prices rise and become more volatile at pipeline capacity load factors well below 100% utilization

During the 2013-2014 winter, daily utilization factors on major inbound pipelines — Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (AGT) —averaged 90% and frequently exceeded 95%. ICF analysis illustrates how traded spot gas prices in New England – and wholesale power prices by extension – can spike and be more volatile when pipeline utilization factor rises above approximately 75% (Figure 2). It is not necessary for the region to experience actual gas capacity deficits for higher costs to materialize.

[15] ISO-NE Press Release on 2014 Annual Markets Report, at http://www.iso-ne.com/static-assets/documents/2015/05/amr14_release_05202015_final.pdf

Figure 2: AGT and TGP Utilization Factor vs. Algonquin City-gates Winter Basis (2011/12 - 2013/14)



Source: Point logic, Ventyx

Reliability and Other Benefits from Access Northeast

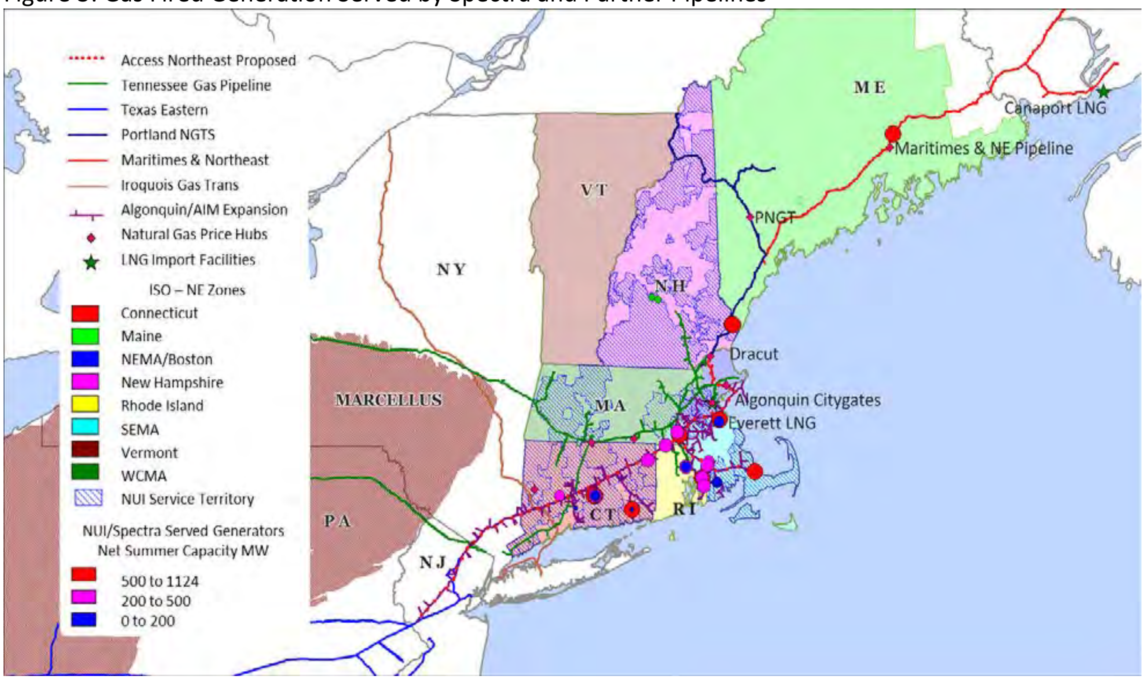
A pipeline such as Access Northeast will enhance New England's grid reliability, complement the ISO-NE's market improvements to incentivize generation availability

Access Northeast can potentially serve 6,900 MW, or nearly 70 percent of the region's existing natural gas fired power generation capacity interconnected to the pipeline system and operating without backup fuel capability. [16] By providing secure fuel supplies to these generators, Access Northeast could significantly improve electric reliability across the grid and help the region avoid costly load shedding measures under extreme circumstances.

Access Northeast is designed to supply a significant amount of new pipeline capacity to both existing power plants and proposed facilities and will provide access to domestically sourced peaking LNG supply during winter periods.[17] This design will optimize the use of natural gas infrastructure by providing year-round access to more natural gas and, when demand for gas is low (typically, Spring, Summer and Fall) storing this domestic gas in regional LNG facilities to be used by electric generation during the Winter. By providing secure fuel supplies to these generators and LNG facilities, Access Northeast could improve electric reliability across the grid.

[16] Data from Spectra Energy, which includes capacity served by ALQ, MN&P and Iroquois.
[17] http://www.spectraenergy.com/content/documents/Projects/NewEngland/Access-Northeast-Project-Brochure.pdf

Figure 3: Gas Fired Generation Served by Spectra and Partner Pipelines



Source: Ventyx

The ISO-NE has developed a market enhancement that is intended to improve generation availability in order to mitigate the adverse consequences of reliability shortage events. This program is known as "Pay for Performance" (or Performance Incentives "PI") and is planned to be implemented by ISO-NE on June 2018. Once the program is in place, severe penalties ($2,000/MWh increasing to $5,455/MWh over time)[18] will be levied on generation that is not available to run at its credited generation capacity level during a generation resource shortage. As ICF has pointed out, currently there could be insufficient firm fuel for as much as 5,700 MW of generation, which means that during winter shortage events the existing gas fired generation units could incur severe penalties if they are not able to dispatch.[19] The infrastructure solution provided by Access Northeast can provide this fuel to follow the hourly gas load variations of power plants, and thereby help ISO-NE meet its system reliability mandate and help generation avoid the PI shortage penalties.

Access Northeast will support the region's renewable energy goals

New England States have ambitious goals for deployment of renewable generation. Due to the intermittent nature of wind and solar generation, additional quick response resources, such as natural gas combustion turbines, are needed as renewables' share of total generation increases. Access

[18] http://www.ourenergypolicy.org/wp-content/uploads/2014/11/ISO_NE_Pay_for_Performance_Initiative.pdf, page 4

[19] Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II, page 21, Exhibit 4-6.

Northeast will provide services that are designed specifically to follow the hourly gas load variations of power plants as electric load and gas fired generation dispatch fluctuates during the day. Access Northeast is also well positioned to provide fuel supplies to ensure that generators have a fuel supply when renewable resources are not generating due to the intermittent and unpredictable nature of the resources.

Introduction

Study Background

For the past 15 years, New England has been steadily increasing its reliance on natural gas-fired electricity generation. At present, approximately 50% of New England's power comes from gas-fired generation, compared to roughly 15%[20] in 2000. The projected retirements of regional nuclear and coal-fired power plants will result in the construction of new gas-fired generation and continue this trend.

The growth in gas-fired generation raises important questions about the reliability of gas supplies to meet that demand. Central to the issue is New England's reliance on interruptible gas supplies for much of its power generation fuel supply. Unlike LDCs, which contract for firm pipeline and storage services to ensure gas supplies (especially on the coldest days), most gas-fired generators in New England rely on non-firm (or "interruptible") pipeline capacity for their fuel supplies. This practice worked in the past because power sector gas demand was concentrated in the summer months, when interruptible pipeline capacity is widely available. However, gas-fired power plants now provide a high percentage of total electric generation throughout the year, including the winter months when LDC demands are high and interruptible capacity is scarce. As more nuclear and coal plants retire and at least some portion of their capacity is replaced by more gas-fired generation, year-round power sector gas demand will continue to increase, and it will be increasingly difficult to meet power sector gas demand on cold days during peak winter months.

In a recent article for IEEE Power & Energy Magazine on conditions during the winter of 2013/14, ISO-NE stated that "subordinate contracts for gas transport were generally not available to power providers."[21] ISO-NE was able to avoid potential brownouts and blackouts during the winter of 2013/14 through the implementation of a number of measures, most notably its "Winter Reliability Program".[22] However, one of the consequences of constraints on gas supplies has been extremely high and volatile natural gas prices during the winter months. This increases the cost of fuel for electric generators, which results in higher electricity costs for New England consumers. All six New England states rank among the top ten U.S. States with the highest residential electricity rates, averaging 45% higher than the U.S. average.[23]

In 2013, the governors of all six New England states issued a joint statement on natural gas and electric system interdependency, and the need for regional cooperation on energy infrastructure issues.[24] In 2015, the governors again released a joint statement, acknowledging that "New England continues to face significant energy system challenges with serious economic consequences for the region's

[20] http://www.iso-ne.com/static-assets/documents/2015/03/icf_isone_van_welie.pdf slide 7.

[21] Babula, M. & Petak, K. (2014). The Cold Truth, Managing Gas-Electric Integration: The ISO New England Experience. IEEE Power & Energy Magazine, November/December 2014, pp 20-28.

[22] A collaboration between ISO New England and regional stakeholders, this project focused on developing a short-term, interim solution to filling a projected "reliability gap" of megawatt-hours (MWh) of energy that would be needed in the event of colder-than-normal weather during winter 2013/2014. The solutions included a demand side response program, an oil inventory service, incentives for dual fuel units, and market monitoring changes.

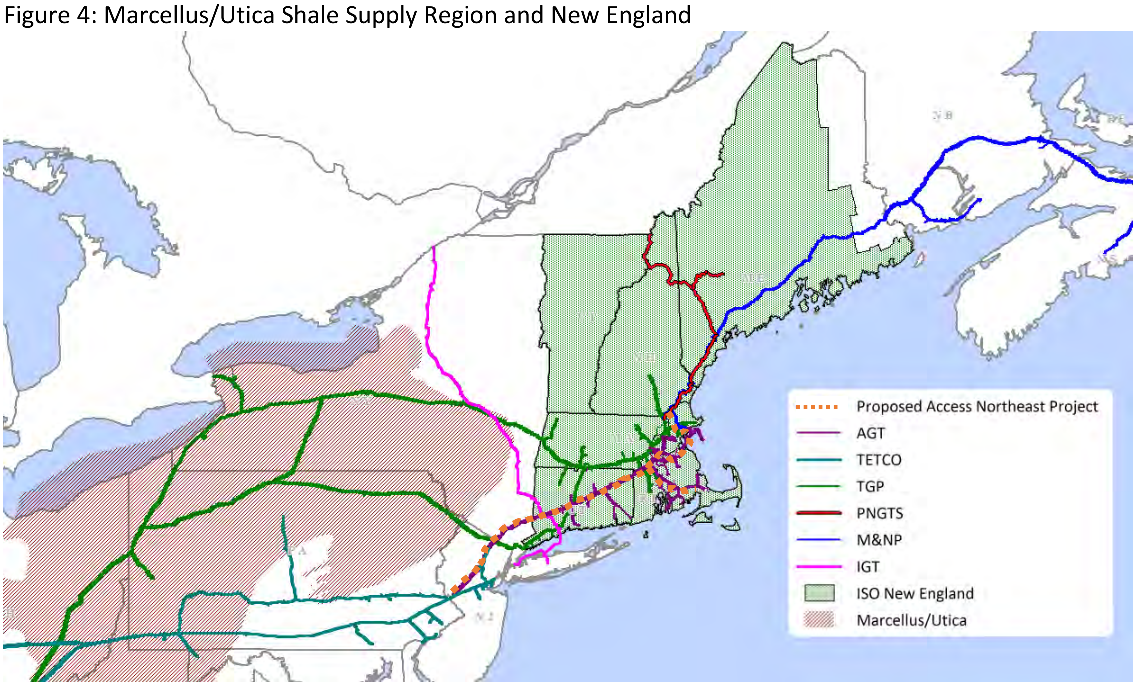
[23] The other states are Hawaii (1), Alaska (4), New York (5) and California (8).

[24] http://nescoe.com/uploads/New_England_Governors_Statement-Energy_12-5-13_final.pdf

consumers. These challenges require cost-effective solutions to reduce consumer energy costs, strengthen grid reliability and enhance regional economic competitiveness”.[25]

New England’s natural gas supply deficit occurs against the back drop of a production boom from the Marcellus and Utica shales in the nearby Appalachian Basin in Pennsylvania, West Virginia, and Ohio (Figure 4). ICF expects that the Appalachian Basin will become the biggest natural gas supply basin in North America, with production from the Marcellus/Utica region projected to more than double, reaching 42 Bcf/d by 2035 (Figure 5).

Figure 4: Marcellus/Utica Shale Supply Region and New England

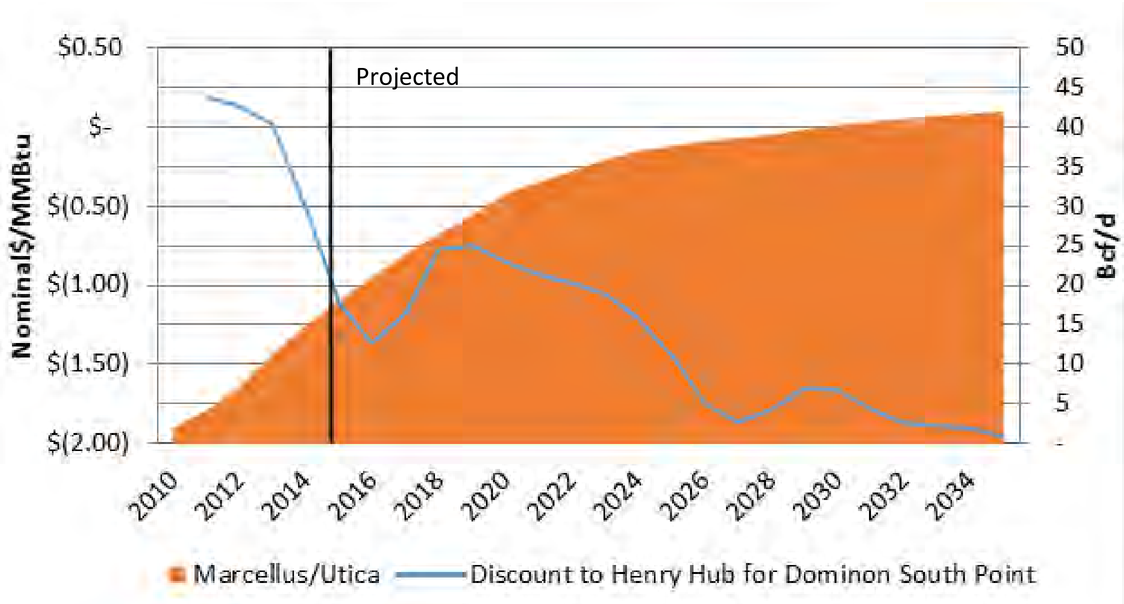


Source: ICF, Ventyx

The dramatic increase in low-cost Appalachian Basin gas production has materially altered the relationship of gas prices there to other trading points across the North American market. As shown on the left axis of Figure 5, the price of natural gas in the Appalachian Basin (represented by the Dominion South Point pricing point in Southwest Pennsylvania) is expected to be traded at significant discount relative to the North American benchmark Henry Hub (Louisiana) price.

[25] http://www.nescoe.com/uploads/6_State_Joint_Statement_FINAL_4-22-15_12-3.36pm_w-sealsf.pdf

Figure 5: Historical and Projected Marcellus/Utica Production and Dominion South Point to Henry Hub Basis[26]



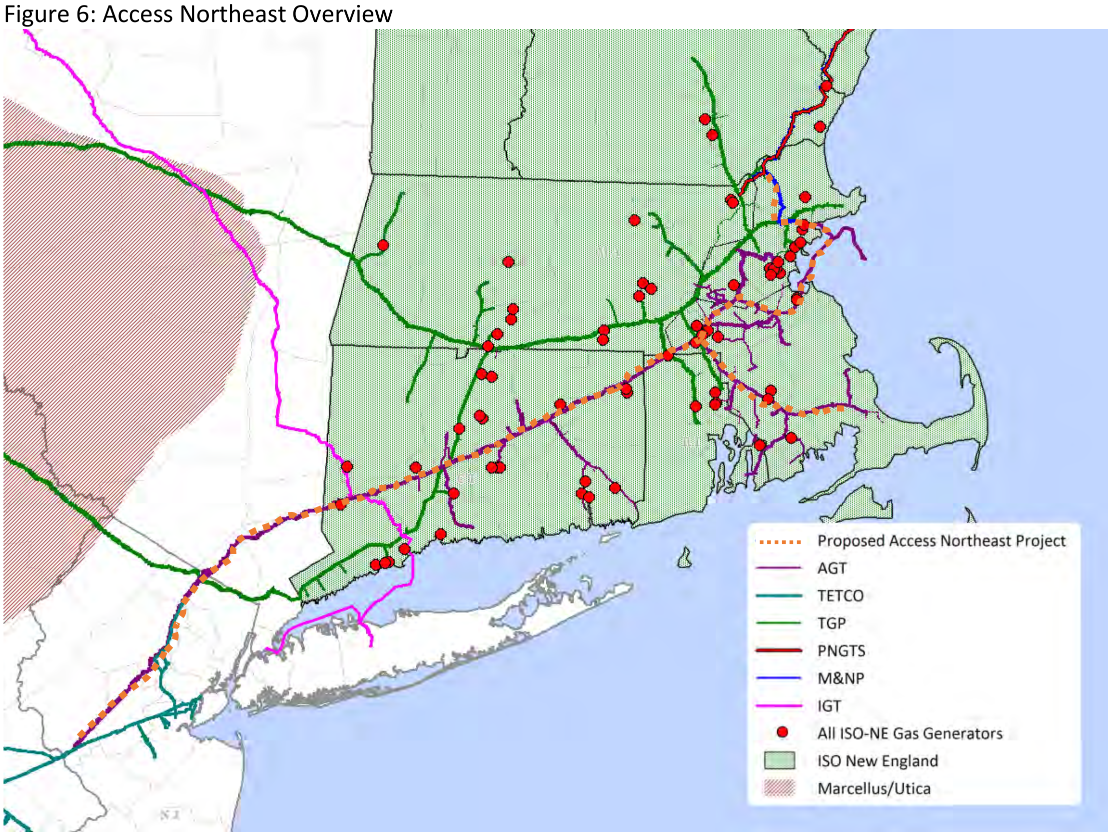
Source: ICF, SNL

Project Description

In response to the emerging need for new firm gas services in New England, Spectra Energy and Eversource have proposed the Access Northeast project to provide scalable deliverability to Power Plant Aggregation Areas (PPAA) to directly serve power plants in order to reach the most efficient power plants on Spectra Energy's Algonquin and Maritimes pipelines. According to the proposal, Access Northeast will provide new Electric Reliability Services (ERS) for firm transportation of natural gas and natural gas supply supported by regional storage facilities for their customers. This proposed service provides greater fuel certainty and performance flexibility for generators through reserved No Notice Transportation with an hourly supply option[27]. For its analysis, ICF has assumed that the project will add 500 MMcf/d pipeline capacity and 6 Bcf of peak LNG supply through storage facilities with a maximum deliverability of 400 MMcf/d, in November 2018. While our modeling has assumed that the full capacity is available in November 2018, it is likely that the proposed project will enter into the market between 2018 and 2021.

[26] Basis presented here is TGP Z4- Line 300 price minus Henry Hub price.
[27] http://www.spectraenergy.com/content/documents/Projects/NewEngland/Access-Northeast-Project-Brochure.pdf

Figure 6: Access Northeast Overview



Source: ICF, Ventyx

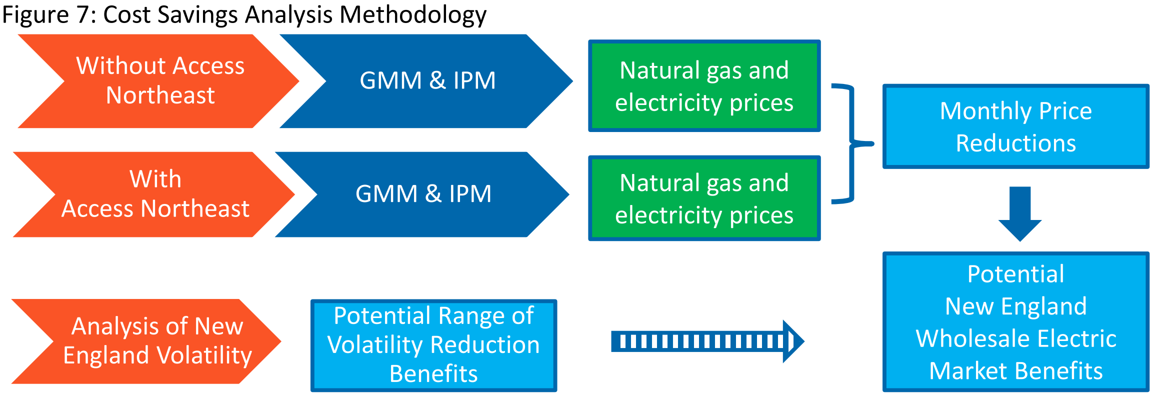
Analytical Approach

ICF's analyses and findings draw from years of experience consulting on North American natural gas and electric markets, as well as the proprietary software tools and databases developed for that purpose. For this analysis, ICF utilized a suite of analytical tools, including its Gas Market Modeling (GMM©) and Integrated Planning Model (IPM®). Descriptions of the models are provided as appendices at the end of this report.

ICF estimates Access Northeast's impacts on New England's electric market by assessing the reduction of wholesale electricity costs – measured as the wholesale energy price multiplied by total energy load in New England. The cost savings are estimated from two perspectives. For the first perspective, ICF examines the reduction of the region's average monthly natural gas and electric prices caused by the additional pipeline capacity from Access Northeast. ICF estimates this impact by running the GMM and IPM models under normal weather conditions with and without Access Northeast, and compares the difference of natural gas and electricity prices between the two scenarios. The price reduction is used to calculate the market impact and potential reduction to New England's wholesale electric costs.

In the second perspective, ICF examines Access Northeast's potential impact on natural gas price volatility by reducing the region's natural gas price spikes, which will result in subsequent reduction in the electric price spikes and provide additional cost savings. This impact is estimated as a potential range using parameters derived from historical data analysis, assuming that the incremental Access Northeast capacity would facilitate a shift in New England's natural gas market environment – either from high to medium or from medium to low volatility regimes. This analytical process is summarized below in Figure 7.

Figure 7: Cost Savings Analysis Methodology



Source: ICF

For the purpose of this analysis, ICF further assumes that reductions or increases in wholesale electric costs would ultimately flow through to all New England electric consumers.

New England Energy Market Fundamentals

For this analysis, ICF revised its October 2015 Base Case to reflect Eversource's assumptions regarding New England natural gas and electric market fundamental development trends through 2035.

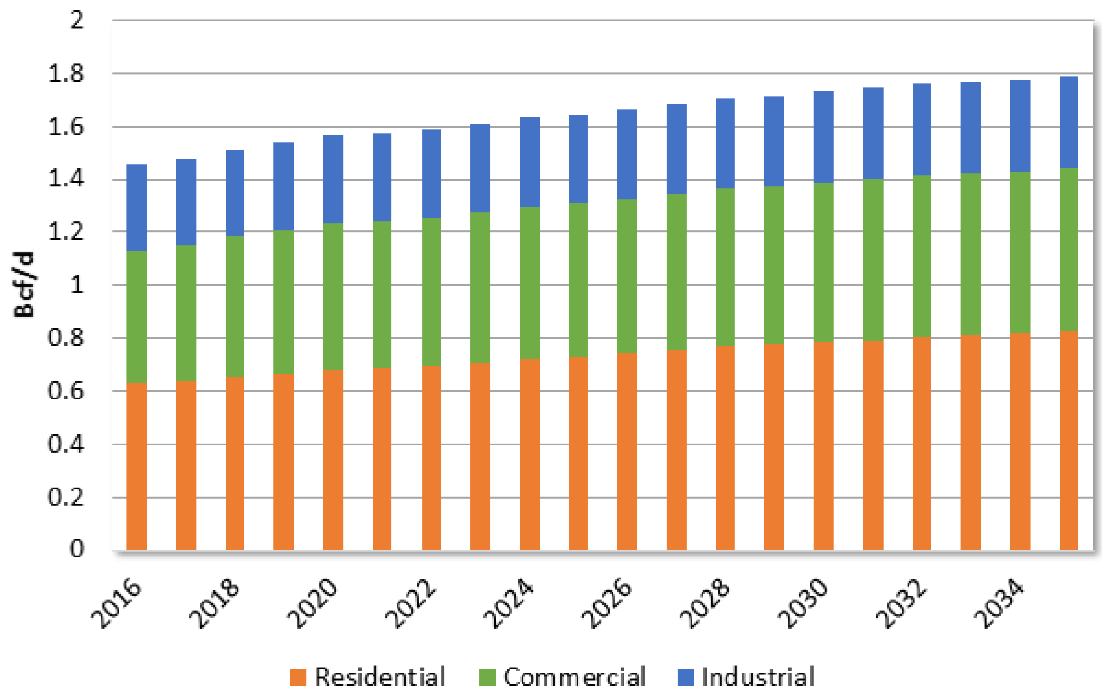
Residential/Commercial Demand

For this analysis, ICF projects New England residential and commercial natural gas demand to grow at a compound annual growth rate (CAGR) of 1.3%, between 2016 and 2035. ICF bases its near-term growth projection on the Integrated Resource Planning (IRP) filings by the 8 largest local distribution companies (LDCs) in New England, by volume of gas delivered.[28]

Through 2018, ICF assumes New England residential and commercial demand will grow at 1.9% and 3.2% over the next two years respectively, based on the LDCs IRP filings. Post-2018, ICF assumed normal weather and projects residential, commercial, and industrial gas demand growth based on a combination of factors, including projected population growth, projected economic growth, the rate of new gas customers additions, and changes in per-household gas consumption. Figure 8 below illustrates ICF's Residential, Commercial, and Industrial demand growth through 2035.

[28] Collectively, these top eight LDCs account for nearly 90% of New England's Residential and Commercial gas consumption; the top eight LDCs include National Grid (MA), Connecticut Nat. Gas Corp (CT), Southern Conn. Gas Co. (CT), Columbia Gas of Mass. (MA), NSTAR Gas Company (MA), Yankee Gas Service Co. (CT), Narragansett Gas Co. (RI), and Liberty Utilities – Energy North (NH).

Figure 8: New England Natural Gas Demand by Sector, Normal Weather, Average Annual Bcf/d



Source: ICF

Industrial Demand

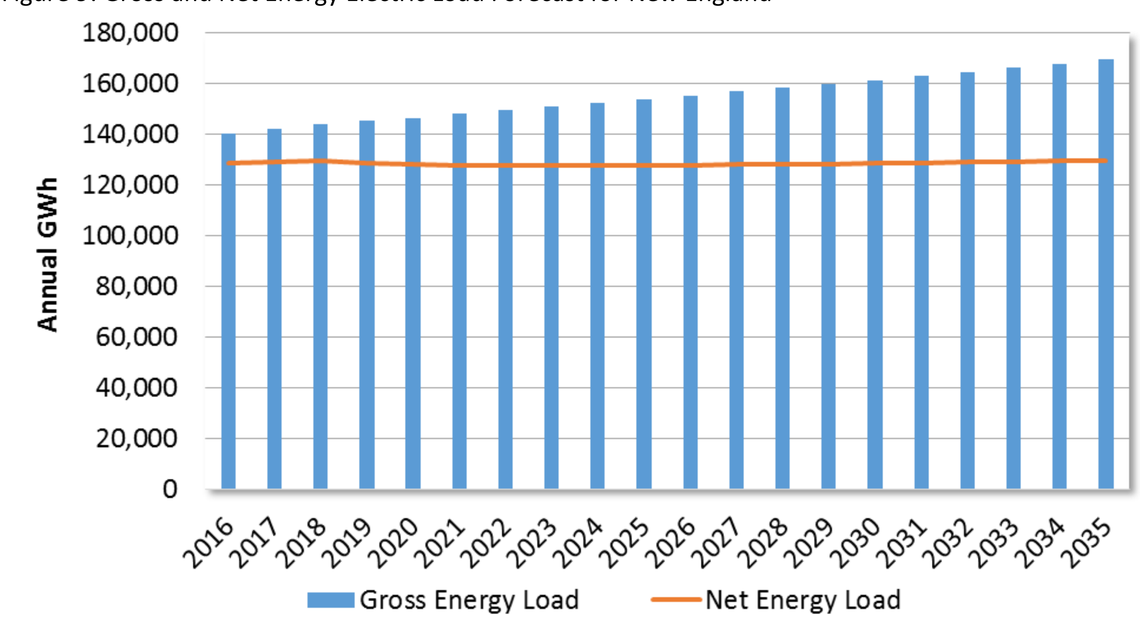
The industrial sector accounts for a relatively small share of New England's total gas demand, and ICF projects very little growth in this sector. As shown in Figure 8 above, annual average industrial demand is projected to be nearly flat at approximately 0.33 Bcf/d throughout the projection, as there are no major new industrial facilities planned in New England.

Gas Demand for the Electric Sector

Electric Load Growth

ICF employed ISO-NE's gross load forecast from 2016 to 2024 growing at the 2022 to 2024 annual average growth rate beyond 2024. Using this forecast, New England's gross electric load is expected to grow at a compound annual growth rate of 1% between 2016 and 2035. However, the assumed growth in energy efficiency and other passive demand resources offsets most of the growth, such that net energy for load grows at an average of 0.04% through 2035 (Figure 9). ICF believes that this projection reflects a relatively conservative assumption regarding New England's net electric load growth, as the Passive Demand Resources (PDR) are assumed to continuously grow at a very rigorous rate, which may not be sustainable in the long-term.

Figure 9: Gross and Net Energy Electric Load Forecast for New England



Source: ICF, ISO-NE

<u>Capacity Retirements and Builds</u>

In this analysis, ICF assumes that approximately 4,150 MW of coal, oil/gas and nuclear generation capacity in ISO–NE is retired by 2019 as shown in Table 2; this includes almost 1,760 MW of capacity already retired by the end of 2014.

Table 2: ISO – New England Firm Retirements[29]

Plant Name	Owner	Capacity Type	State	Year	MW
Lowell Cogeneration Plant	Alliance Energy NY	Gas	MA	2013	28
Norwalk Harbor 1-3	Norwalk Power LLC	Oil/Gas	CT	2013	342
Cabot Holyoke: 6	Holyoke City of MA	Oil/Gas	MA	2013	10
Cabot Holyoke: 8	Holyoke City of MA	Oil/Gas	MA	2013	10
Salem Harbor 4	Dominion	Oil/Gas	MA	2014	437
Bridgeport Harbor 2	PSEG	Oil	CT	2014	182
Salem Harbor 3	Footprint Power	Coal	MA	2014	150
Vermont Yankee 1	Entergy	Nuclear	VT	2014	604
Mt. Tom	GDF Suez	Coal	MA	2015	144
Kendall Steam	GenOn	Gas	MA	2016	25
Brayton Point 1-4 and Peaking	ECP	Coal/Oil/Gas	MA	2017	1535
Pilgrim	Entergy	Nuclear	MA	2019	685
Total					**4151**

Source: ICF

Based on announced capacity additions, ICF assumes about 1,740 MW of firm natural gas generation capacity (capacity that cleared the forward capacity auctions) will be added in ISO – NE by 2019 (Table 3).

[29] Retirements considered firm if they are permanently delisted units or if they have submitted a non-price retirement request that ISO-NE has accepted.

Table 3: ISO – New England's Firm Capacity Additions by 2019 (MW)

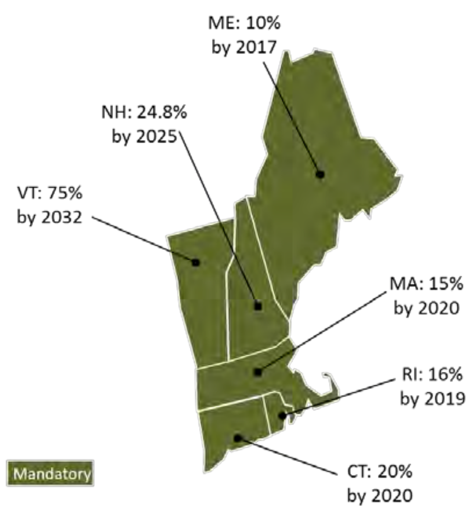
Fuel	2015	2016	2017	2018	Total
Biomass			7		**7**
Solar[30]		4	1	16	**21**
Wind	64	7	6		**77**
Water	2	48			**50**
Landfill Gas			1	1	**2**
Oil/Gas		39			**39**
Natural Gas	10		690	1043	**1743**
Total	**76**	**98**	**704**	**1060**	**1938**

Source: ICF

Renewables

ICF assumes that all New England states' Renewable Portfolio Standards ("RPS") are met according to currently proposed timelines. Each state's respective RPS goals can be seen below in Figure 10.

Figure 10: New England State RPS Standards



Source: ICF, state's RPS

Environmental Regulations

For this analysis, ICF assumes that federal maximum achievable control technology (MACT) standards, consistent with those set by the Environmental Protection Agency (EPA) in its final mercury and air toxics standards (MATS) released on December 21, 2011, will be in effect throughout the projection. ICF also assumes that the EPA will not have an alternative to the current Clean Air Interstate Rule (CAIR)

[30] Solar does not include "behind the meter" residential and commercial solar installations, which are not included in the ISO-NE queue. The 2015 ISO-NE CELT Forecast assumptions used in the modeling are net of these "behind-the-meter" solar installations.

regulations, and that the current CAIR remains in place through 2017. In 2018, ICF-assumed standards tighten to the Cross State Air Pollution Rule (CSAPR) Phase II requirements.

Clean Power Plan (CPP)

ICF incorporated the regulatory impacts of EPA's Clean Power Plan (CPP), recently finalized on August 2015 for this analysis. While the EPA's final rule has been issued, there is still considerable uncertainty about future CO_2 control policy, because the CPP allows for multiple paths to comply. Additional, several states have filed legal challenges to the CPP Rule. To represent continued uncertainty over the future implementation of carbon policy, ICF has used its Integrated Planning Model (IPM) to assess the impact of three policy cases:

- No CO2 Policy Case, which is considered increasingly unlikely after 2020;
- Middle Case, based on mass caps over existing fossil units as outlined in the CPP Final Rule;
- High Case, assuming implementation of a more stringent, multi-sector emission control policy.

Results from these three cases have been used to create probability-weighted CO_2 allowance prices in the power sector, which in turn drive electric capacity retirements, new builds, and dispatch decisions that are reflected in ICF's projected gas demand and prices.

Projected Supply Sources into New England

New England's primary source of natural gas supply is now Marcellus/Utica production, which is then transported to New England's LDCs principally via TGP and AGT. During peak winter months New England also relies on both peak shaving facilities operated by LDCs as well as intermittent LNG imports via LNG import terminals. Canadian production from Nova Scotia and transported on M&NP has dwindled in recent years and no longer serves as a primary source of natural gas supplies to New England during peak winter months.

LNG Imports

New England has one onshore LNG import facility, Distrigas's Everett LNG terminal. Between 2010 and 2014, total volumes delivered out of Everett declined by 81%. In response to cold weather and higher prices, volumes rebounded slightly in January 2015, but the 2014/15 peak winter sendout was still less than half of the 2011 volumes. ICF projects annual average and peak winter sendout from Everett to be similar to the 2014-2015 winter levels, declining slightly after new pipeline capacity (AIM, TGP CT, and Atlantic Bridge) is added. This assumption remains unchanged for all of analysis provided herein.

New England also has two offshore LNG import terminals: Neptune and Northeast Gateway. Neptune has not received shipments since 2010, and in 2013 suspended its deep-water port license. Northeast Gateway received two shipments in January 2015, its first since 2010. ICF projects that neither Neptune nor Northeast Gateway are likely to provide gas supplies to New England in the future.

Canadian Supplies via M&NP

M&NP has nominal capacity to deliver up to 0.8 Bcf/d into New England. M&NP was originally designed to bring production from Sable Island Offshore Energy Project (SOEP) to markets in the Maritimes Provinces and New England. M&NP also receives production from the Deep Panuke offshore field and a small onshore field (McCully).

Weaker-than-expected production from SOEP left M&NP underutilized. In 2008, Repsol commissioned Canaport LNG in New Brunswick, which has provided additional supplies for M&NP. In 2013, Repsol sold its LNG supply contracts and ship charters to Shell, leaving Canaport with only a small fixed supply contract.

Even as Eastern Canadian production and LNG imports have declined[31], gas demand in the Maritimes provinces has been increasing. While relatively small, at about 0.2 Bcf/d, demand in the Maritimes provinces uses supplies that could otherwise be exported to New England. Flows on the M&NP system have already reversed on occasion, with gas flowing north into New Brunswick. Even if Canaport continues to import at or slightly above recent levels, the Maritime Provinces are likely to be net gas importers by 2020. As such, M&NP is unlikely to provide gas supplies during the winter peak starting in 2020.

Firm Pipeline and Supply Capacity into New England

TGP, AGT, PNGTS, and IGT have existing firm contracts into New England that total about 3.1 Bcf/d. Three planned pipeline expansions (AGT AIM and Atlantic Bridge, and TGP Connecticut) will provide about 0.6 Bcf/d of additional gas supplies into New England on peak winter days. Based on sendout over the past two winters, Everett is expected to provide no more than 0.25 Bcf/d during peak winter periods. M&NP is still expected to provide some winter supplies in the next few years, but then drop to zero due to decreasing supplies and increasing demand in the Maritime Provinces. This leaves New England with winter gas supplies of about 4 Bcf/d by 2020, as shown in Table 4.

[31] On Jun 25, 2015, CBC News reported that ExxonMobil Decommissioning manager Friederich Krispin said that “the work [decommissioning SOEP] will begin as early as 2017 when the company hires a rig to plug and abandon wells.”

NSTAR Electric Company and Western Massachusetts Electric Company
each d/b/a Eversource Energy
D.P.U. 15-181
Exhibit EVER-KRP-3
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Table 4: Assumed Winter Capacity from Existing Pipelines, Planned Expansions, and LNG Supplies to New England (Bcf/d)[1]

	Supply Path	2020 - 2035
Expected Supplies from Existing Pipelines and LNG Imports	TGP	1.41
	AGT	1.35
	IGT[2]	0.21
	PNGTS[3]	0.17
	M&NP[4]	0
	Everett LNG	0.25
Supplies from Pipeline Expansions	AIM	0.34
	TGP - Connecticut Expansion	0.07
	Atlantic Bridge	0.13
	Total Pipeline and LNG Supplies	**3.95**

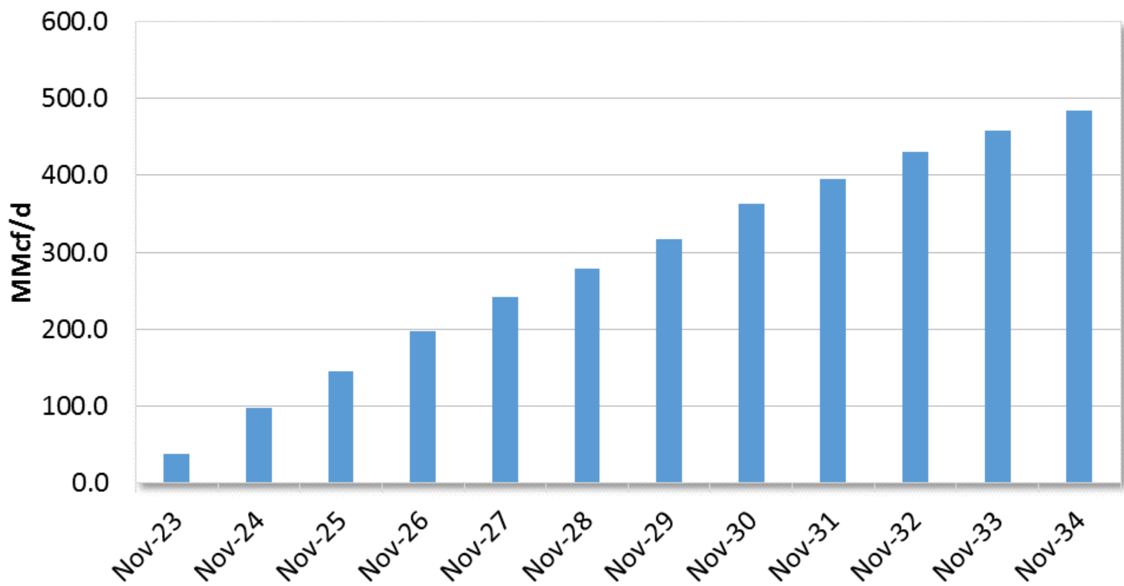
Source: ICF

1. Unless noted, the table reflects operational capacity. Historical data shows that physical flows occasionally exceed operational capacity under certain conditions.
2. IGT capacity is estimated using firm contracts with receipt points outside of New England and delivery points to end customers in New England according to second quarter 2015 IGT Index of Customers.
3. PNGTS operational receipt capacity at Pittsburg.
4. Due to declining production in offshore Nova Scotia, no firm supply from Eastern Canada is expected into New England during the winter months by 2020.

LDC Incremental Expansions

The energy demand/supply trends described above indicates that New England faces the risk of persistent and growing natural gas supply constraints, absent new sources of capacity. Given the current structure of the regional energy markets, such risks could disproportionately affect electricity markets, raising economic and potential service reliability concerns for consumers across the region. Access Northeast is proposed to help address the electric market's needs for incremental infrastructure. In order to isolate Access Northeast's impact on the natural gas and electric market, ICF assumes that the LDC needs for incremental capacity is immediately met with continuous expansions so than total January residential, commercial and industrial demand amounts to 75% of total firm capacity into New England. The expansions are assumed to be on-line in November of each year. As shown in Figure 11, LDC load will require additional expansions to start in 2023 and cumulatively reach approximately 500 MMcf/d by 2035.

Figure 11 – Cumulative Capacity Expansion for LDCs Load Requirements



Source: ICF

Electric Consumer Cost Savings - Normal Weather

ICF has estimated the energy market impact of Access Northeast by running GMM and IPM models under normal weather conditions with and without the project, and has then compared the difference for natural gas prices and wholesale power prices. The wholesale power price reduction was then used to calculate the market impact and potential cost savings to New England electric consumers. In addition, the project's impact on natural gas price volatility and the resulting further reduction to electric price spikes were then estimated separately utilizing a statistical approach.

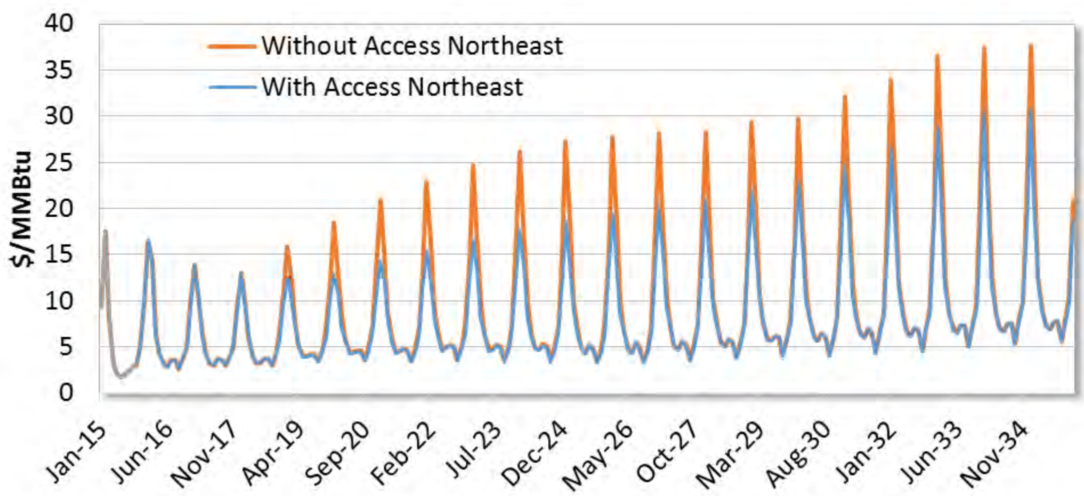
Natural Gas Price Impact – Monthly Average

Figure 12 shows that without Access Northeast, under normal weather conditions, ICF projects that peak winter month gas prices in New England will initially decline from the levels seen in the past two winters. Incremental capacity expansions (such as AIM, Tennessee's Connecticut Expansion, and Spectra's Atlantic Bridge) will temporarily contain the peak winter price for three years before demand growth and Eastern Canada supply declines outpace the expanded capacity. Peak winter prices then will steadily increase over time and exceed, in 2024, the levels experienced in the Polar Vortex winter of 2013/14 and surpass a monthly average of $30/MMBtu by 2030.

In this projection, Access Northeast significantly lowers peak winter gas prices. Even though prices continue to rise as the market responds to demand growth and supply declines, peak winter monthly prices are projected to be substantially lower than levels reached in the 2013/14 winter. During the peak winter months of December, January and February, Access Northeast would reduce prices by as much as $8.60/MMBtu. On an annual average basis, Access Northeast reduces New England's natural gas prices by $1.30/MMBtu over the 17-year period between 2019 and 2035. While this difference is below the unit cost of the pipeline, suggesting that Access Northeast's benefit is less than its cost, the actual benefit from the pipeline as measured with electric price change for all electric consumers is much greater than the cost of the pipeline (as shown in the section that directly follows).[32] Further, this measure does not include the additional benefit that results from reductions in daily price volatility that are also discussed below.

[32] The reduction impact in New England's natural gas price will be amplified dramatically on the power market, as every unit of electricity consumed in New England will be priced lower when the natural gas fired generation units determine the wholesale power prices.

Figure 12: New England Natural Gas Price Forecast – Monthly Average

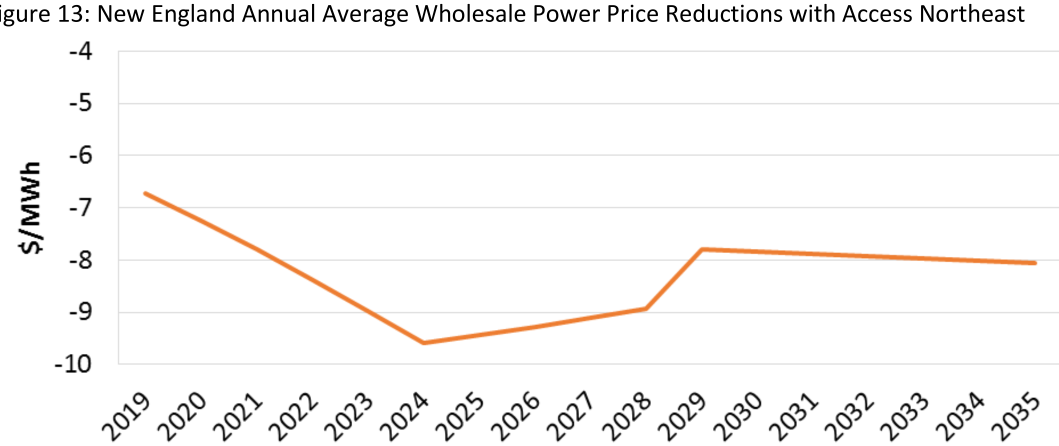


Source: ICF, SNL

Wholesale Power Price Impact – Monthly Average

New England's wholesale power prices are closely related to natural gas prices due to the region's dependence upon gas-fired power generation capacity. By reducing spot prices in New England, the Access Northeast market project would have a direct impact on New England's wholesale power prices. As shown in Figure 13, Access Northeast reduces the New England annual average wholesale power price by $6/MWh to $10/MWh between 2019 and 2035.

Figure 13: New England Annual Average Wholesale Power Price Reductions with Access Northeast

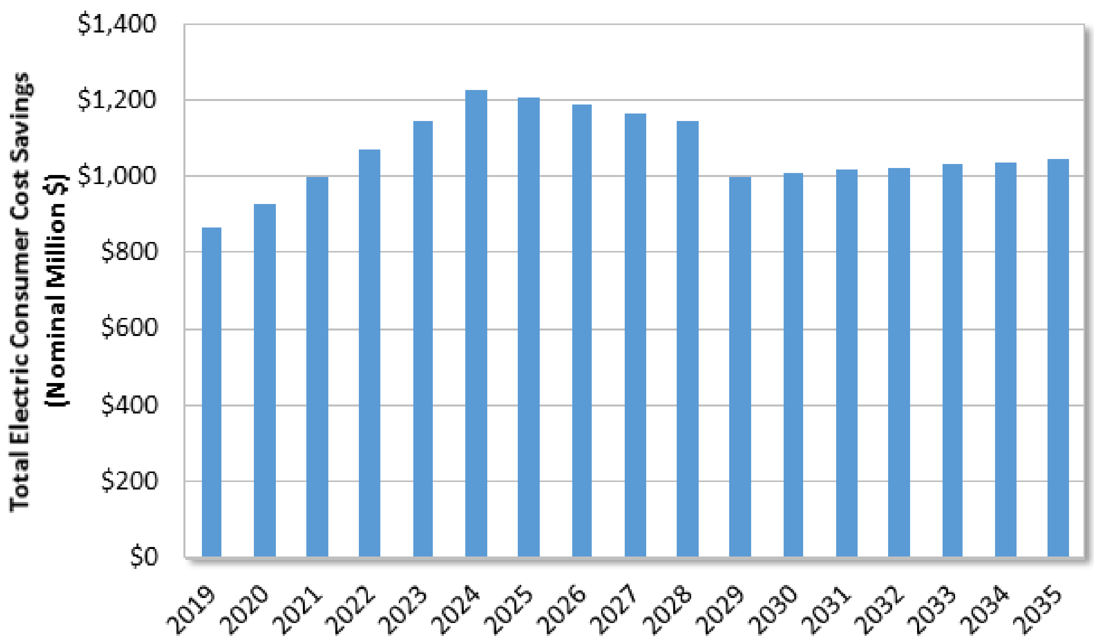


Source: ICF

Cost Savings from Average Price Reductions

The analysis results presented above show that Access Northeast would reduce New England's wholesale electricity prices by lowering the regional natural gas price and the fuel costs for gas-fired power generation. In this analysis, ICF assumes that wholesale power price reduction provided by infrastructure solutions reduces the wholesale costs across New England. Annual wholesale power cost savings are calculated as the reduction in New England's wholesale energy prices multiplied by ISO-NE annual net energy load. ICF estimates that Access Northeast would potentially generate annual cost savings of $860 million to $1.2 billion[33] for the 17-year period between 2019 and 2035, averaging $1.1 billion, as shown in Figure 14.

Figure 14 – Annual Energy Cost Savings from Monthly Average Electricity Price Reduction



Source: ICF

Benefits from Reduced Daily Gas Price Volatility

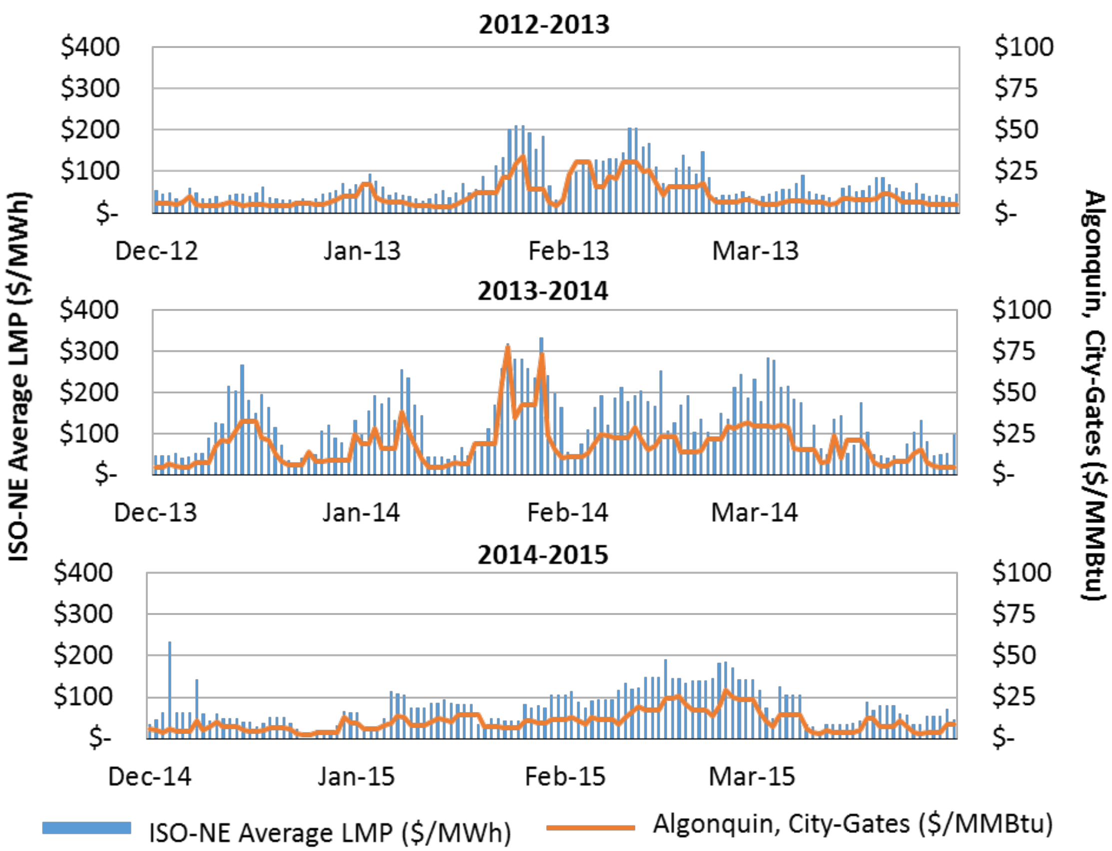
In addition to the monthly average price reduction that ICF has estimated using the GMM and IPM models, the gas supply capacity created by a project like Access Northeast would produce additional cost savings through reductions in daily natural gas and power price volatility. New England's gas and wholesale power prices both exhibit asymmetric patterns – daily prices can spike up to extremely high levels, but only decline modestly. Therefore, reduction in the frequency and magnitude of natural gas and electricity price spikes would potentially result in price reductions beyond the monthly average levels discussed above. ICF estimated the potential impact of volatility only for the peak winter months of December through March.

Price volatility is determined by complex market drivers, the analysis of which is beyond the scope of this report. For this study, ICF assumed certain ranges of reduction of frequency and magnitude of

[33] The cost savings discussed throughout this report do not include potential revenues from capacity released into the market.

extraordinary price spikes as a proxy to measure the impact of volatility reductions. Figure 15 presents daily Algonquin City Gate gas prices and ISO-NE daily average real-time locational marginal prices (RTLMPs—prices for electricity at different locations in the grid) for the past four winters.

Figure 15 - New England Historical Gas and Electric Price Volatility



Source: ICF, SNL, ISO-NE

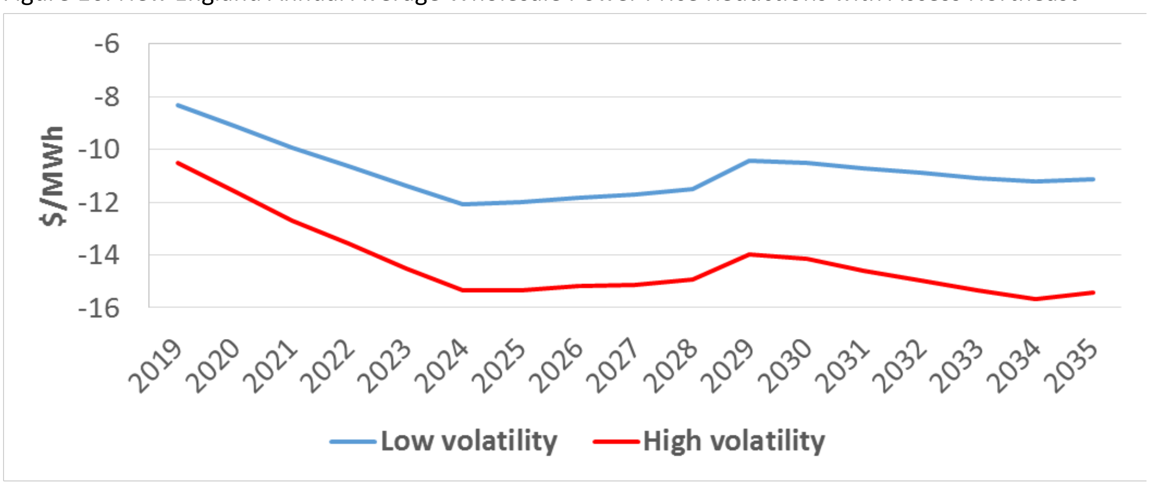
As discussed previously, future fundamental natural gas market development trends in New England, including increases in natural gas demand and diminishing supply sources from Canada and LNG imports, would increasingly stress the natural gas infrastructure serving New England and create significant constraints during peak winter months and highly volatile prices even under normal weather conditions, similar to the volatilities observed under extreme weather conditions in North American for the polar vortex winter of 2013/2014. Therefore, without incremental capacity such as Access Northeast, New England natural gas price would become increasingly volatile even under normal weather conditions.

The range of Access Northeast's potential volatility reduction impacts is estimated assuming two volatility reduction levels:

- Low Volatility Reduction Assumption - Frequency and size of price spikes are reduced by approximately half from a moderate volatility market, similar to what was experienced in the 2012/2013 or 2014/2015 winter;
- High Volatility Reduction Assumption - Frequency and size of price spikes are reduced by approximately half from a high volatility market, similar to what was experienced in the 2013/14 winter.

These assumptions result in greater wholesale power price reductions as shown in Figure 16, which in turn generate additional cost savings of $0.33 billion to $0.77 billion per year on average over the 17-year period of 2019 through 2035.

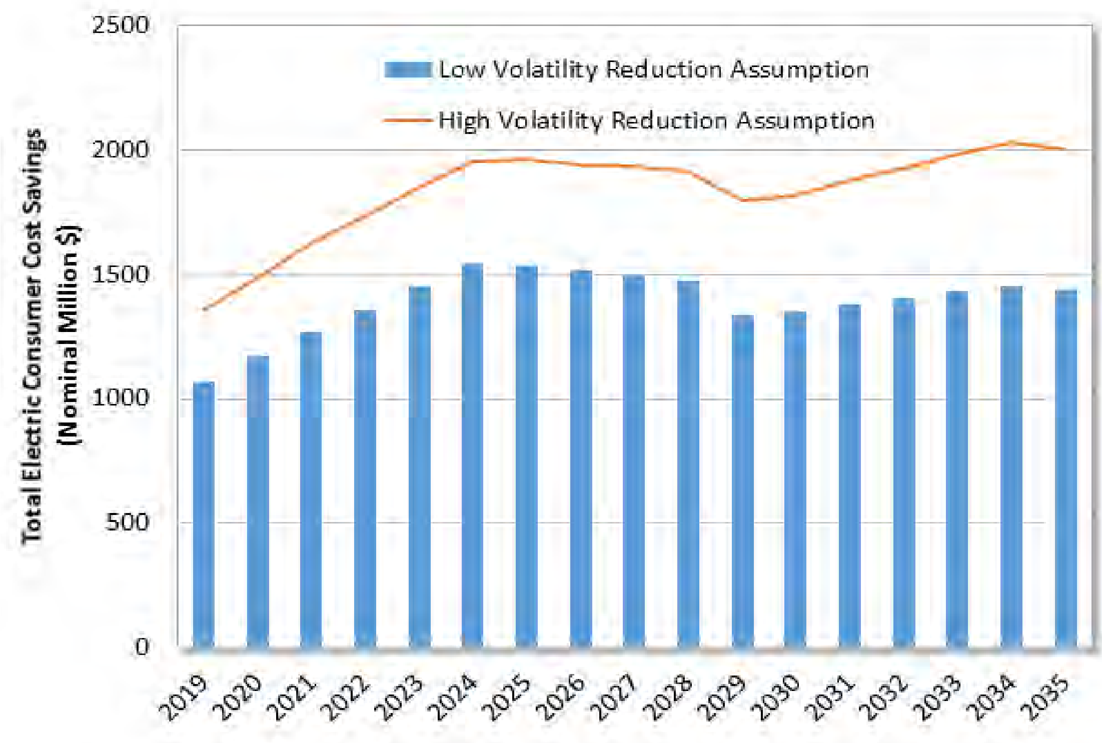
Figure 16: New England Annual Average Wholesale Power Price Reductions with Access Northeast



Total Estimated Impact to Consumers

With Access Northeast reducing prices of natural gas and thus reducing the price of wholesale power for New England consumers, Figure 17 shows that the savings from Access Northeast varies over time from about would generate $1.1 billion to $2.0 billion per year to New England electric consumers, depending on volatility conditions. The annual average cost savings to consumers due to the lowered electricity prices alone for the 17-year period is $1.1 billion, and adding the benefits of volatility reductions results in $1.4 billion to $1.9 billion for the low and high volatility assumption scenarios, respectively.

Figure 17 - New England Electric Consumer Cost Savings, including volatility



Source: ICF

Total Estimated Impact to Consumers by State

The consumer benefits accrue to the different New England states differently, depending on the net load and the electricity price savings in each of the states; see Table 5. Consumers in Massachusetts, Connecticut, and New Hampshire are the states will benefit the most from the Access Northeast project, because these states have the largest percentage of load. The benefits in these three states account for 80% of the total ISO-NE benefits, with Massachusetts consumers accounting for about 45% of the benefits.

Table 5: State-wise Electric Consumer Average Annual Savings (in nominal million dollars) 2019 to 2035 Under Different Volatility Assumptions

States	Load (TWh)	No Volatility	Low Volatility	High Volatility	% of Savings
Massachusetts	58.1	$480	$630	$830	45%
Connecticut	32.5	$290	$370	$480	26%
New Hampshire	12.8	$110	$140	$185	10%
New England ISO	128.4	$1,090	$1,410	$1,850	100%

Source: ICF

Note: State-wise benefits were computed from ISO-NE RSP Subarea model results based on the RSP Subarea to State allocation specified in Table 3-4 of the 2014 ISO-NE Regional System Plan.

Electric Consumer Cost Savings - Cold Weather and Nuclear Outage Scenario

ICF assessed the impact of Access Northeast by assuming that the winter of 2021-2022 is a "1-in-20 year design" winter, and simultaneously experiences a large nuclear outage event. For the electric market, ICF also used the 90-10[34] scenario from ISO-NE's CELT report that has a significantly higher peak energy load profile than under the normal weather conditions.

Weather and RCI Demand Assumptions

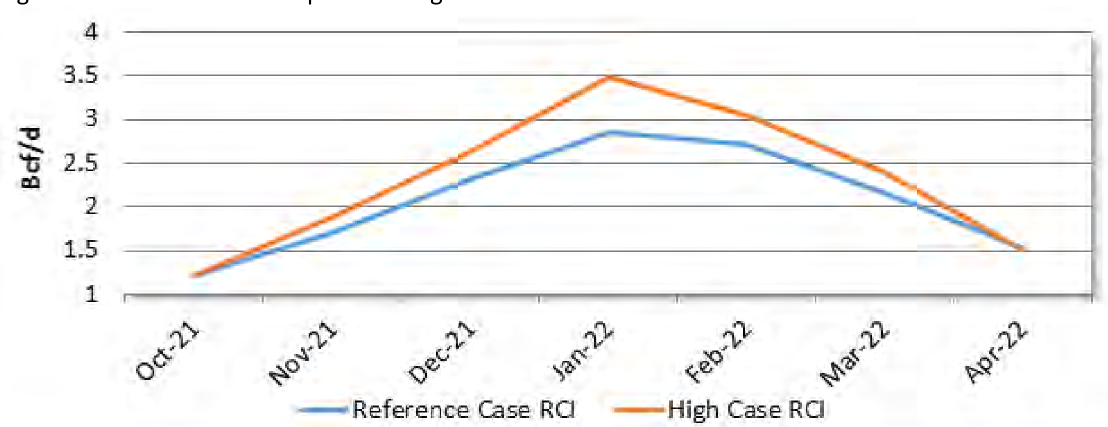
ICF utilized the design winter weather data provided by Eversource, to calibrate the design winter conditions in New England. Table 6 shows that the design winter is, on average, 17 percent colder than normal winter conditions. Figure 18 shows that residential, commercial, and industrial demand for the five winter months is 14 percent higher than under normal weather conditions.

Table 6: Weather Assumptions

	Normal HDDs	1-20 Design HDDs	Design Winter Colder %
November	708	812	15%
December	1036	1188	15%
January	1222	1522	25%
February	1052	1207	15%
March	916	1051	15%

Source: Eversource, ICF

Figure 18 - RCI Demand Comparison - High Winter Case vs. Reference Winter Case



Source: ICF

[34] The 90/10 scenario refers to ISO-NE's electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 10%. Therefore, a high electric load demand is estimated.

Price Impact and Cost Savings

Under the cold weather and nuclear outage scenario, Access Northeast is expected to have a more significant impact on natural gas and electric markets. Table 7 shows that on average (before taking volatility into consideration), natural gas prices would be reduced by about $15/MMBtu during peak winter month, and electric prices would be reduced by nearly $80/MWh.

Table 7: Colder than Normal Winter Scenario Power and Gas Price Results in New England

	Gas Price Savings ($/MMBtu)	Electricity Price Savings ($/MWh)	Consumer Savings ($ million, nominal)
Nov 2021	$1.9	$7	$90
Dec 2021	$10.2	$40	$590
Jan 2022	$14.9	$80	$1,120
Feb 2022	$9.4	$45	$610
Mar 2022	$2.8	$13	$190
2021-22 Winter	**$7.8 (Avg.)**	**$37 (Avg.)**	**$2,600 (Total)**

Source: ICF

Access Northeast would generate approximately $2.6 billion cost savings to electric consumers in the five winter month period, and about $3.1 billion of costs savings on an annualized basis.[35] The total annualized consumer savings (2021-22) by state under the cold weather and nuclear outage scenario is shown in Table 8.

Table 8: State-wise Annualized Savings under Colder than Normal Winter and Nuclear Outage Scenario

	Annualized Consumer Savings ($ million, nominal)
Massachusetts	$1,390
Connecticut	$780
New Hampshire	$270
ISO-NE	$3,100

Source: ICF

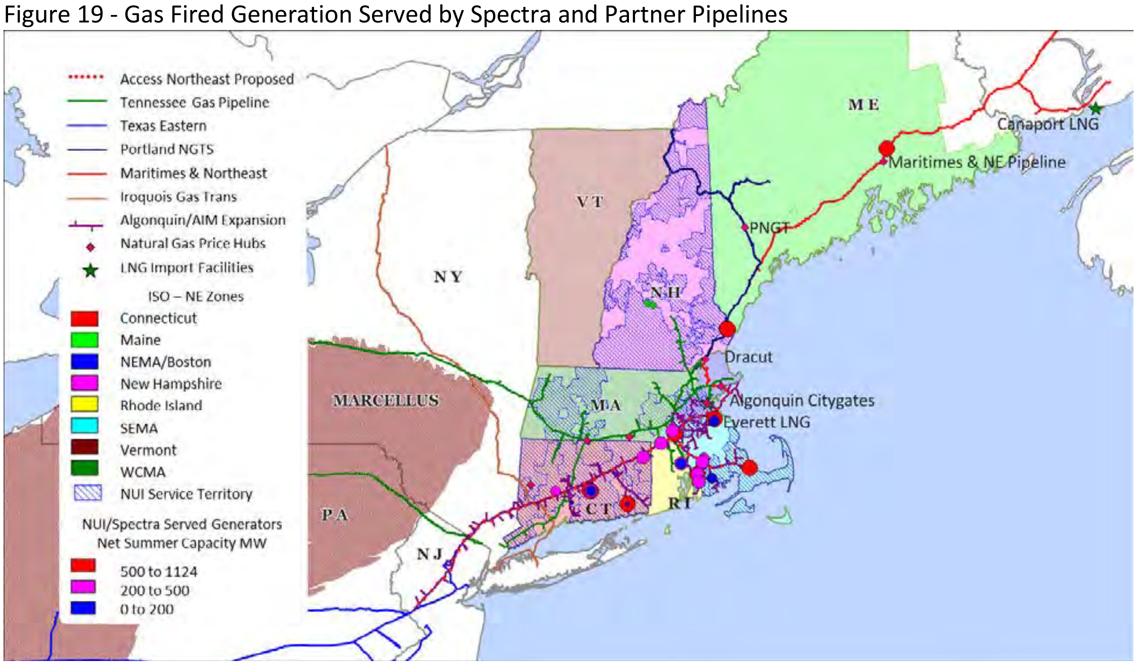
[35] Annualized savings are calculated as savings from November 2021 to October 2022.

Reliability and Other Benefits

Access Northeast would increase ISO-NE's electric system reliability by directly providing firm natural gas fuel for gas fired power generators and help New England potentially avoid costly load shedding measures under extreme circumstances.

To maintain electric system reliability and potentially prevent spikes in wholesale electricity prices, New England's gas-fired electric generators will need access to firm, reliable and economic natural gas supplies, particularly during the winter months. Access Northeast is designed to supply a significant amount of new pipeline capacity to both existing power plants and proposed facilities and will provide access to domestically sourced peaking LNG supply during winter periods. This design will optimize the use of existing natural gas infrastructure by providing year round access to more natural gas and, when demand for gas is low (typically, Spring, Summer and Fall) storing this domestic gas in regional LNG facilities to be used by electric generation during the Winter. Figure 19 shows that the proposed project can potentially serve 6,900 MW, or nearly 70 percent of the region's existing natural gas fired power generation capacity interconnected to the pipeline system and operating without backup fuel capability[36]. By providing secure fuel supplies to these generators, Access Northeast could significantly improve electric reliability across the grid.

Figure 19 - Gas Fired Generation Served by Spectra and Partner Pipelines



Source: Ventyx

[36] Including connections with ALQ, MN&P and Iroquois.

The ISO-NE has developed a market enhancement that is intended to improve generation availability in order to mitigate the adverse consequences of reliability shortage events. This program is known as "Pay for Performance" (or Performance Incentives "PI") and is planned to be implemented by ISO-NE on June 2018. Once the program is in place, severe penalties ($2,000/MWh increasing to $5,455/MWh over time) will be levied on generation that is not available to run at its credited generation capacity level during a generation resource shortage. As ICF has pointed out, currently there could be insufficient firm fuel for as much as 5,700 MW of generation, which means that during winter shortage events the existing gas fired generation units could incur severe penalties if they are not able to dispatch.[37] The infrastructure solution provided by Access Northeast and the Electric Reliability gas supply service, is capable of providing fuel for up to 5,000 MW and can provide this fuel to follow the hourly gas load variations of power plants. Access Northeast will, therefore, help ISO-NE meet its system reliability mandate and help generation avoid the PI shortage penalties.

In addition, the value of pipeline capacity reliability for a region increases materially as gas use for power generation grows. Without adequate gas capacity, New England's electric system could face costly load shedding measures. Studies regarding the estimated costs of power service outages are limited, but a 2013 filing with state regulators by Potomac Electric Power (PEPCO), a PJM electric utility that serves Maryland and Washington D.C., provides one benchmark. In that filing, summarized in Table 9, PEPCO estimated that an eight-hour outage for a quarter of its customers could cost approximately $988 million. Access Northeast can help New England avert this type of costly electric load shedding.

Table 9: Estimated Costs of Outages by PEPCO in 2013 Maryland State Filing

Customer Class	Total Cost per Customer for an 8 hour Outage ($)	One Quarter of Total Customers	Estimated Costs for an 8 Hour Outage affecting a quarter of Total Customers ($)
Residential	11	58,774	623,004
Small Commercial and Industrial	5,195	65,453	340,027,569
Large Commercial and Industrial	69,284	9,350	647,833,633
TOTAL		**133,557**	**$988,484,206**

Source: PEPCO

New England states have ambitious goals for deployment of renewable generation. Due to the intermittent nature of wind and solar generation, additional quick response gas-fired generation is needed as renewables' share of total generation increases. Access Northeast will provide services that are designed specifically to follow the hourly gas load variations of power plants as electric load and gas fired generation dispatch fluctuates during the day. Access Northeast is also well positioned to provide fuel supplies to insure that generators have a fuel supply when renewable resources are not generating due to the intermittent and unpredictable nature of the resources.

[37] Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II, page 21, Exhibit 4-6.

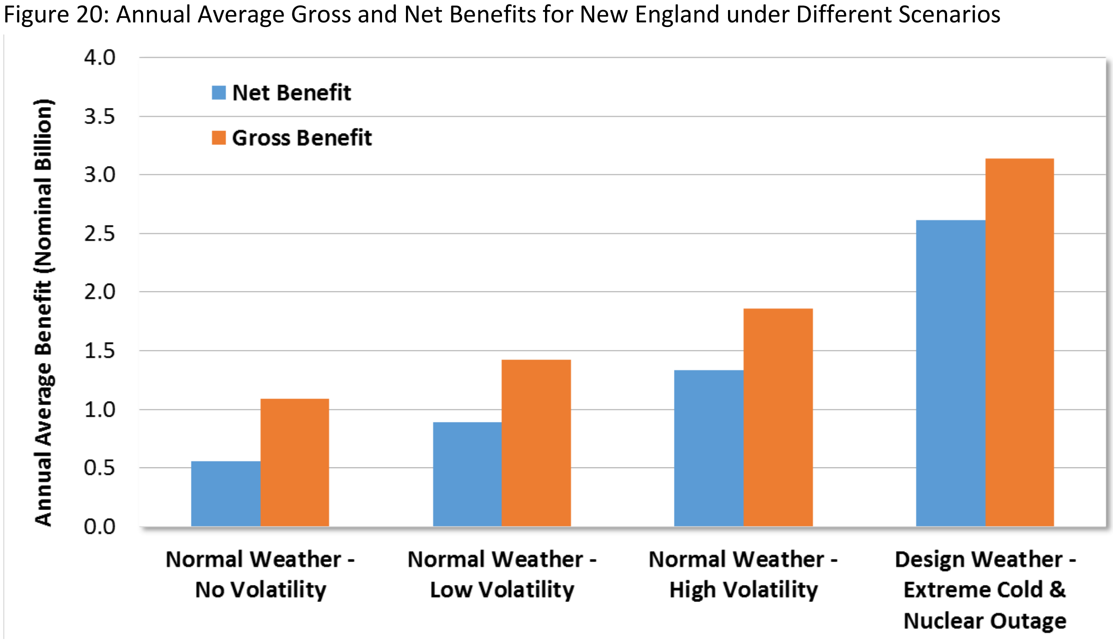
Cost / Benefits of Access Northeast

The portion of Access Northeast that will serve electric generation in New England, assumed in ICF's analysis is estimated to cost $3.2 billion. Assuming this translates into a $526 million annual cost, after taking into account the return on the capital investment and O&M costs annually to operate the capacity, the estimated benefits of Access Northeast to New England exceed its costs in all scenarios.

Table 10: Annual Access Northeast Benefits and Cost Summary (Average of 2019-2035)

	New England (Nominal Billion)	MA (Nominal Million)	CT (Nominal Million)	NH (Nominal Million)
Normal Weather (Low Volatility)	$1.4	$630	$370	$140
Normal Weather (High Volatility)	$1.9	$830	$480	$185
Design Weather (2021-2022)	$3.1	$1,390	$780	$270
Costs	$0.5	TBD	TBD	TBD
Net Benefits (Low-High Volatility)	$0.9 - $1.3	--	--	--

Figure 20: Annual Average Gross and Net Benefits for New England under Different Scenarios



Source: ICF

The net benefits to New England, ranging from $1.0 billion to $2.7 billion, assumes that New England's electric consumers bear the full cost of the electric portion of the project, so those costs are netted out of the total savings that ICF has estimated. However, the cost savings to consumers would be greater if projected revenues for pipeline reservation charges paid by electric generators were to be credited back to the consumers as is proposed. We also estimate that the majority of the $3.2 billion investment required for the project would be recovered from the cost savings in a single extreme winter (design winter), similar to the 2013/14 winter. Furthermore, consumers in Massachusetts, Connecticut, and New Hampshire stand to benefit the most from the electric savings due to Access Northeast, due to the allocation of load.

Appendix: Description of ICF Models

ICF's Gas Market Model (GMM®) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. Since then, the GMM has been used to complete strategic planning studies for governments, non-government associations, utilities, and private sector companies. The different types of studies include:

- Analyses of pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure 1). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

There are nine different components of ICF's model, as shown in Figure 2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The gas consumption for the power sector is matched with the outputs from the IPM model (described below), and the two models (GMM and IPM) are run together until the gas prices and power sector gas consumption are converged.

The GMM model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure 3. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The supply component may be integrated with the GMM to solve for deliverability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (*i.e.*, gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (*i.e.*, end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

Figure 1: Natural Gas Supply and Demand Curves in the GMM

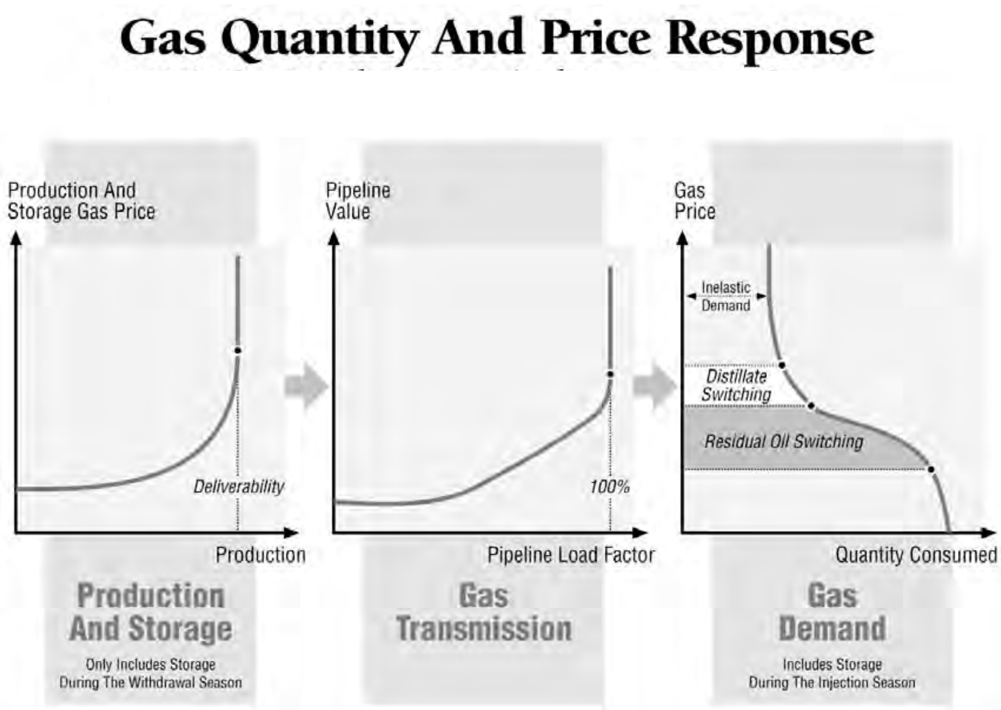


Figure 2: GMM Structure

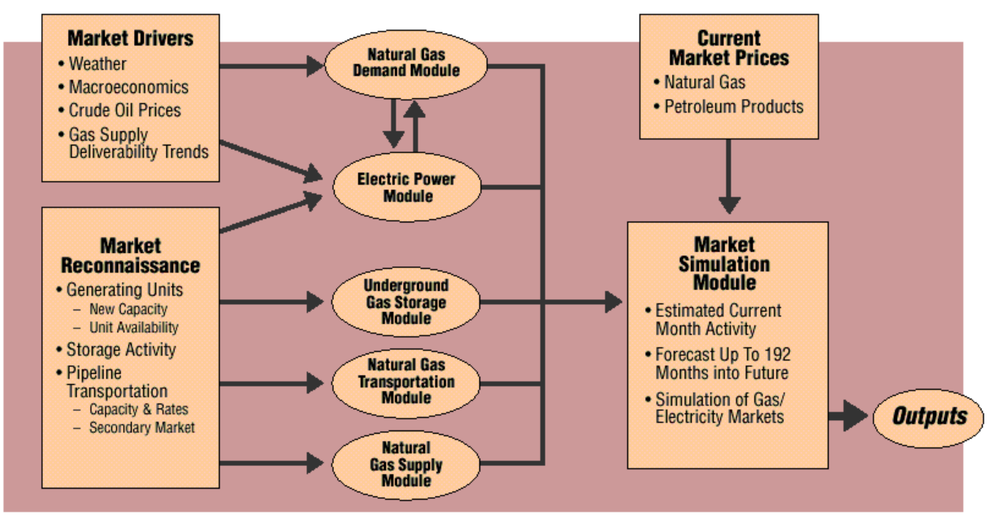
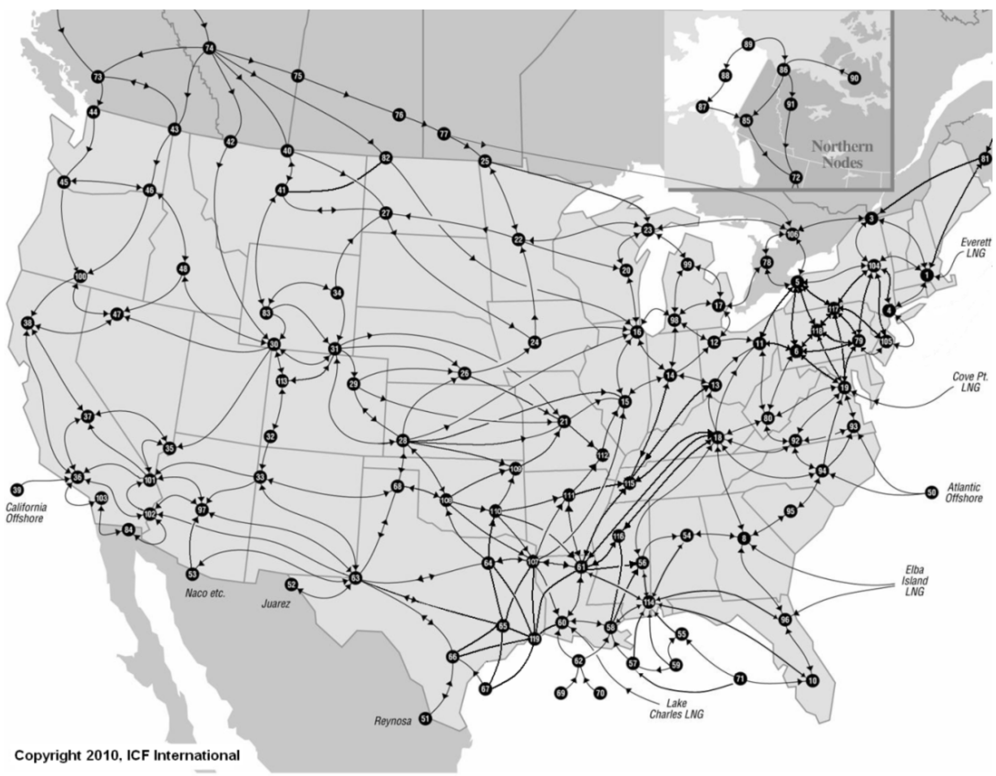
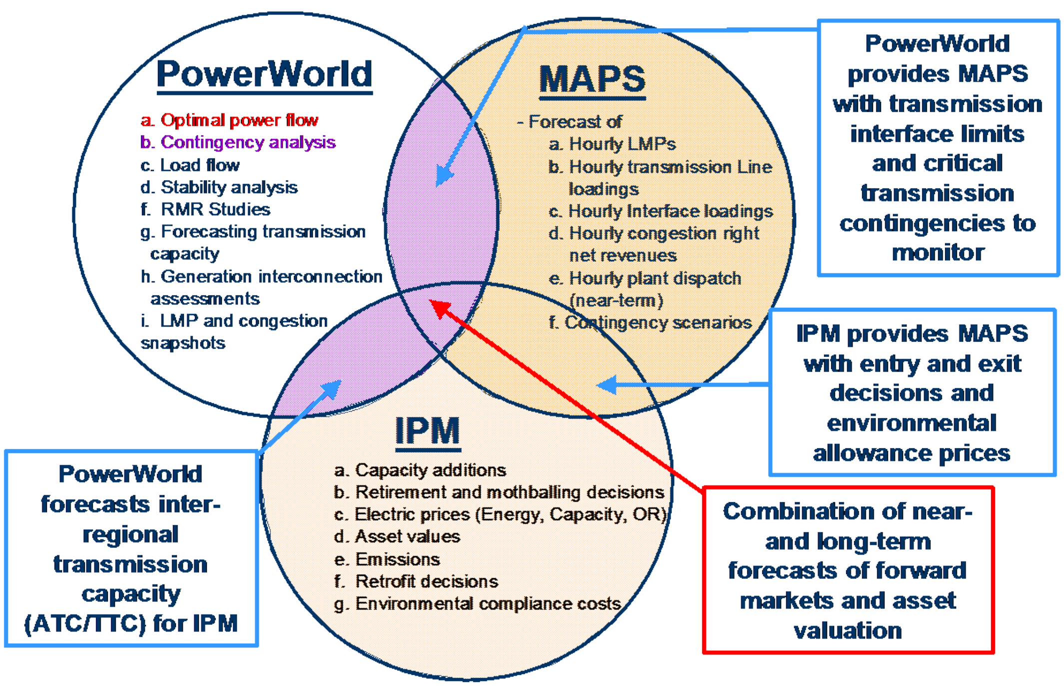


Figure 3: GMM Transmission Network



ICF utilizes several modeling tools to simulate the power markets (see Figure 4). ICF has calibrated these tools internally to produce consistent market results and often combines the tools to perform overlapping analysis. For Eversource, we have used ICF's proprietary Integrated Power Model (IPM®) to determine short and long term demand for natural gas in New England. Subsequently, ICF used GEMAPs to model New England's power grid in the cold winter and nuclear outage scenario.

Figure 4: ICF Analytical Tools Focus on Specific Problems



The Integrated Planning Model (IPM®) - IPM® is a detailed engineering/economic capacity expansion and production-costing model of the power and industrial sectors supported by an extensive database of every boiler and generator in the nation. It is a multi-region model that provides capacity and transmission expansion plans, unit dispatch and compliance decisions, and power and allowance price forecasts, all based on power market fundamentals. IPM® explicitly considers gas, oil, and coal markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals. Figure 5 illustrates the key components of IPM®.

IPM® uses a dynamic linear programming model the electric demand, generation, and transmission within each region as well as the transmission grid that connects the regions.

Figure 5: IPM Framework

All existing utility-owned boilers and generators are modeled, as well as independent power producers and cogeneration facilities that sell firm capacity into the wholesale market. IPM® also is capable of explicitly modeling individual (or aggregated) end-use energy efficiency investments. Each technology (e.g., compact fluorescent lighting) or general program (e.g., load control) is characterized in terms of its load shape impacts and costs. Costs can be characterized simply as total costs or more accurately according to its components (e.g., equipment or measure costs, program or equipment costs, and administrative costs), and penetration curves reflecting the market potential for a technology or program. End-use energy efficiency investments compete on a level playing field with traditional electric supply options to meet future demands. As supply side resources become more constrained or expensive (e.g., due to environmental regulation) more energy efficiency resources are used.

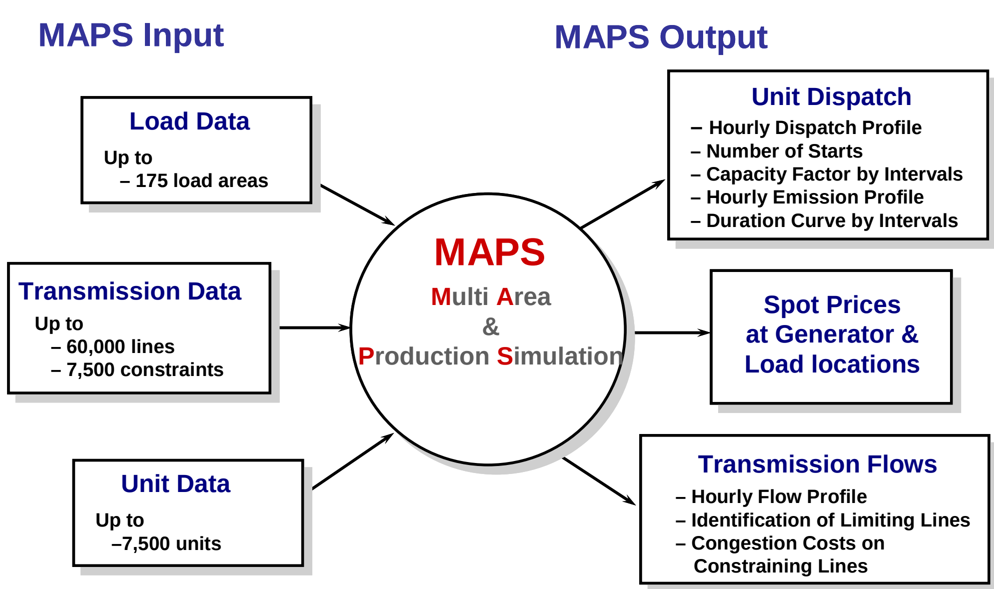
Outputs of IPM® include estimates of regional energy and capacity prices, optimal build patterns based on timing of need and available technology, unit dispatch, air emission changes, retrofit decisions, incremental electric power system costs (capital, FOM VOM), allowance prices for controlled pollutants, changes in fuel use, and fuel price impacts. Results can be directly reported at the national and power market region levels. ICF can readily develop individual state or regional impacts aggregating unit plant information to those levels.

ICF regularly analyzes transmission issues including the grid impacts of generation and bulk power transactions, transmission congestion costs, load pocket isolation issues, value of transmission assets, and the tradeoff between transmission expansion and generation expansion. The PowerWorld Simulation model and the General Electric Multi-Area Production Simulation model (GEMAPs®) are the primary tools utilized. For this Eversource work, ICF relied on the GEMAPs tool to identify the impacts of cold weather and nuclear outage scenario.

GE's Multi Area Production Simulation Model – ICF is a licensed user of GEMAPS, a highly detailed model that chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. GE-MAPS uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved alternating current (AC) load flow, to calculate the real power flows for each generation dispatch. This enables MAPS to capture the economic penalties of re-dispatching generation to satisfy transmission line flow limits and security constraints.

The outputs of GEMAPS include hourly locational marginal prices for all generator and load busses, hourly forecast of congestion across transmission lines and interfaces and associated congestion cost, system-wide congestion cost, and hourly dispatch of generation units (see Figure 6).

Figure 6: GEMAPS Framework



McKEE-GRID 1-4

Request:

Refer to Schedule AEL-2:

A. In which line item are revenues expected from capacity release and the sale of LNG accounted for?

B. What are the levelized benefits to National Grid ratepayers of those revenues?

Response:

A. The capacity release and the sale of LNG will be included in Line 1. However, as described in part B, the Company did not include any capacity release credits and credits from the sale of LNG in Schedule AEL-2.

B. The Company did not include any credits associated with the capacity release and sale of LNG in the calculation of the levelized benefits to National Grid customers. In Schedule AEL-2, the Company calculated the CCR factor as well as the offsetting Energy Savings Factor, both of which were used to calculate the illustrative bill impacts found in Schedules AEL-3 and AEL-4, absent any reduction due to revenues associated with capacity release or LNG storage services. These illustrative bill impacts demonstrate that customers are expected to experience bill savings over the term of the contract, even under a hypothetical scenario in which the Company receives no proceeds from the release of capacity or LNG storage services to offset the costs under the contract. In other words, the projected reduction to Standard Offer Service rates over this period would more than offset the cost of the ANE contract including an innovative incentive.

Prepared by or under the supervision of: Ann E. Leary

McKEE-GRID 1-5

Request:

Is it true that National Grid is making no commitment regarding any reduction in the Capacity Cost Recovery Factor based on revenues from the resale of gas transportation capacity in the Access Northeast project? If the answer is yes, doesn't this add risk for the distribution ratepayers?

Response:

Yes, the Company did not include revenue from the resale of transportation and storage capacity in the Capacity Cost Recovery Factor. The benefit-to-cost analysis Black & Veatch performed for the Company incorporated the fixed pipeline and storage demand charges and the benefit from lower electric prices as a result of the incremental pipeline and storage capacity. Any value generated from the pipeline and storage capacity will only increase the benefit side of the benefit to cost analysis. The Company wanted to take a more conservative approach knowing that any revenue from the pipeline and storage capacity would reduce the Capacity Cost Recovery Factor. This more conservative approach does not add risk but rather reduces the customer's risk.

McKEE-GRID 1-6

Request:

Please provide a forecast of the value of the Capacity Cost Recovery Factor year by year for the 20-year term of the agreement. Is it ever anticipated to be negative, i.e. a credit to ratepayers?

Response:

In the Company's response to Data Request PUC 1-1, the Company provided all discovery responses submitted in the Massachusetts docket, D.P.U. 16-05, Request for Approval of Firm Transportation Contracts with Algonquin Gas Transmission, LLC for the Access Northeast Project. In this response, the Company included its response to Information Request AG 1-46, which provided the annual ANE contract cost for each year over the life of the contract. As indicated in response to Data Request McKEE-GRID 1-5, the Company has not included at this time any forecast of the amount of capacity release credits that would be received over the life of the contract, which would offset the contract costs. Since the Company has not forecasted the capacity release credits, the Company does not know if the Capacity Cost Recovery Factor would ever be a credit. However, in Schedule AEL-2 and Schedule AEL-3, the Company demonstrates that even without the offsetting capacity release credits, customers will realize savings over the life of the contract due to reductions in Standard Offer Service rates.

Prepared by or under the supervision of: Ann E. Leary

McKEE-GRID 1-7

Request:

How will the capacity prices charged to electric generators by our Capacity Manager compare to:

A. Comparable capacity arrangements that other market suppliers will be charging gas fired electric generators in the same period? How will we know?

B. Comparable capacity contracts for gas local distribution companies? How will we know?

C. Comparable capacity purchases by large industrial customers? How will we know?

Response:

Capacity released by the Capacity Manager will be biddable and will be awarded to the highest bidder just as capacity from other sources. All capacity release prices will be posted and available to all market participants.

McKEE-GRID 1-8

Request:

Brennan/Allocca's testimony states on page 36: "Section 39-31-3 defines the phrase 'commercially 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."

A. Who are the experienced power market analysts in this docket?

B. Do you agree that, in order to establish credibility, any power market analyst ought to be a disinterested party (not employed or hired by any party that has a financial interest in the project)?

Response:

A. John E. Allocca is the relevant "experienced power market analyst" in this docket with respect to whether the terms and pricing of the ANE Agreement are reasonably consistent with similar transactions. As the Brennan/Allocca testimony states on pages 3-5, Mr. Allocca is the Director of Gas Contracting and Compliance for National Grid USA Service Company, is responsible for the acquisition of long term gas supply and pipeline capacity for The Narragansett Electric Company, and has significant experience negotiating similar firm transportation agreements with interstate pipeline companies serving the region.

B. No. The analyst who was responsible for negotiating and evaluating the agreement, and testifying as to its reasonableness, on behalf of the customers of the relevant company (in this case The Narragansett Electric Company) did so fairly and without regard to the potential financial interest of an affiliated company (in this case National Grid Algonquin, LLC). See Brennan/Allocca Testimony, pages 48-51, for a discussion of the protocols and Standards of Conduct that National Grid implemented to ensure that any eventual solicitation and evaluation process would be conducted in a fair and transparent manner.

Prepared by or under the supervision of: Timothy J. Brennan

McKEE-GRID 1-9

Request:

What other comparable bid in terms of type of resource, size of resource, and pricing structure do we have from the Company's procurement process that selected the Access Northeast project, so that we can directly compare the prices we are paying and the other terms of the Access Northeast agreement?

Response:

National Grid received a total of eight separate responses to the Request For Proposal (RFP). Black & Veatch reviewed the proposals submitted in response to the RFP and determined which responses were eligible for further economic analysis. Please see Schedule RWP-3 for the summary matrix of proposals.

Of the eight separate responses, four of them were classified as gas pipeline infrastructure responses in Schedule RWP-3. These four responses differed in project size, project timing, and ability to provide primary firm to power generators. Of these four responses, the Tennessee Gas Pipeline Northeast Energy Direct response is the most comparable to the Access Northeast project.

Prepared by or under the supervision of: Timothy J. Brennan, Denny K. Yeung and Gary J. Wilmes

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McKEE-GRID 1-10

Request:

Is it typical for experienced analysts to rely on modeled changes in wholesale prices to determine whether the terms and pricing of a pipeline capacity contract is reasonable? Or is it more typical for experienced analysts to rely on multiple bids for the same or similar resource need and directly compare terms and pricing between the competitive bids?

Response:

Black & Veatch utilized a two-step process to review the responses to the Request for Proposals (RFP) and evaluate the long-term economic benefits to electric customers. In the initial step, Black & Veatch reviewed the eight separate responses to the RFP, and determined which responses sufficiently satisfied the key requirements of the RFP to undergo additional analysis. Please see Schedule RWP-3 for a summary matrix of the responses to the RFP, and Schedule RWP-4 for the matrix of key S1 requirements for all proposals.

In the second step, Black & Veatch analyzed the wholesale gas and electric price impact of the RFP responses that sufficiently satisfied the key requirements of the RFP. In this step, Black & Veatch evaluated the long-term economic benefits to electric customers and compared the net benefits of the various responses. Please see Schedule GJW-3 Table 7 for a summary of costs and benefits across the various scenarios.

Black & Veatch's two-step process reviewed multiple responses to the RFP and evaluated the net benefits of the responses that sufficiently satisfied the key requirements. Black & Veatch's review and evaluation process led to the conclusion that the ANE Project is expected to generate significant annual net benefits to New England electric customers.

REDACTED

McKEE-GRID 1-11

Request:

Brennan/Allocca testimony states on page 37, lines 4 and 5, that the ANE Agreement's "terms and pricing are consistent with interstate gas capacity contracts recently approved in the region."

A. Please provide details of the recently approved gas capacity contracts referred to, including parties involved and dates of approval.

B. Please provide a table that lines up the terms and pricing of the ANE Agreement with these other recently approved contracts.

Response:

A. The Algonquin Incremental Market (AIM) Project was approved in Massachusetts in D.P.U. 13-157 on January 31, 2014. The parties to that agreement are Boston Gas Company and Algonquin Gas Transmission, LLC. The project will provide firm gas transportation service from Algonquin's interconnection with Millennium at Ramapo, New York to various end users in New England including The Narragansett Electric Company. The expected rate under that agreement is between [redacted] per Dth.

The Tennessee Northeast Energy Direct Project was approved in Massachusetts in D.P.U. 15-34 on August 31, 2015. The parties to that agreement are Boston Gas Company and Tennessee Gas Pipeline Company. That project would have provided firm gas transportation service from the interconnections with Constitution and Iroquois at Wright, New York to various end users in New England including The Narragansett Electric Company. The expected rate under that project was between [redacted] per Dth.

B. See table below:

Project	Service	Receipt Point(s)	Delivery Point(s)	Expected Rate
ANE	Firm Transportation	Ramapo, etc.	New England	[redacted]
AIM	Firm Transportation	Ramapo	New England	
Northeast Energy Direct	Firm Transportation	Wright	New England	

Prepared by or under the supervision of: John E. Allocca

McKEE-GRID 1-12

Request:

Please provide any and all market research that answers the following questions about the Access Northeast project:

A. Who are our customers?

B. What are our customers' needs when it comes to our product line?

C. What price are our customers likely to be willing to pay?

D. What product features are valuable to our customers?

E. Who are our competitors and what is their pricing strategy?

Response:

This question appears to stem from the same, incorrect underlying premise as Data Request McKEE-GRID 1-2—i.e., that "National Grid is proposing that the Company and its electric distribution ratepayers go into business together" to purchase natural gas products "for resale, primarily to electric generators." Presumably, such a purported business venture would require market research to understand customers, valued product features, and competitors. However, the Company's response to Data Request McKEE-GRID 1-2 explains why this premise is false. In short, the Company's proposal seeks to address a market failure that is saddling Rhode Island customers with excessive electricity costs. In the responses below, the Company describes how its proposal meets the need for incremental natural gas pipeline and storage capacity on the part of gas-fired electricity generators in New England.

A. The Joint Testimony of Timothy J. Brennan and John E. Allocca explains that:

> [t]he 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.[1]

In addition, the testimony of Richard J. Kruse on behalf of Algonquin Gas Transmission, LLC, in D.P.U. 16-05 before the Massachusetts Department of Public Utilities explained that:

> Algonquin's system is the primary natural gas delivery infrastructure for providing natural gas to electric generators in New England. Algonquin alone serves 44% of the natural gas-fired electric generators in New England and, when combined with Maritimes, serves approximately 60%. Directly connected power generator capability currently served by Algonquin and Maritimes is estimated to be nearly 9,500 megawatts ("MW"). By 2020, approximately 2,600 MW of additional generation is expected to be directly connected to Algonquin.[2]

B. The Joint Testimony of Timothy J. Brennan and John E. Allocca explains in detail how the ANE Project addresses the particular needs of gas-fired generators in New England:

> 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 New England market region, which ISO-NE has described as a just-in-

[1] Joint Testimony of Timothy J. Brennan and John E. Allocca, at 21-22.

[2] D.P.U. 16-05, Exhibit ALGONQUIN-RJK-1, at 4-5 (July 11, 2016). A copy of this exhibit is provided as Attachment McKee-1-12.

time fuel delivery system. 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 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 (at 39-41).[3]

[3] Joint Testimony of Timothy J. Brennan and John E. Allocca, at 42-43.

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 control. Some pipelines currently offer no-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 fast-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 real-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.

A new level of service will be provided [by the ANE project] under the customized ERS tariff rate, which will provide fuel certainty and performance flexibility critical to the electric generators by virtue of a reserved "no-notice" transportation service with an hourly supply option.[4] .

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

[4] Joint Testimony of Timothy J. Brennan and John E. Allocca, at 23

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 fast-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.[5]

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.[6]

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 "no-notice" service

5 Joint Testimony of Timothy J. Brennan and John E. Allocca, at 28-29.
6 Joint Testimony of Timothy J. Brennan and John E. Allocca, at 32.

> and follow their generation load requirements and avoid scheduling penalties. [The ANE project's] 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.[7]
>
> The [ANE storage] 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.[8]

In addition, the testimony of Richard J. Kruse on behalf of Algonquin Gas Transmission, LLC, in D.P.U. 16-05 before the Massachusetts Department of Public Utilities explained that:

> Not only is Access Northeast the only solution that will provide the majority of New England's natural gas-fired generators with firm, reliable, direct access to natural gas supply from diverse, domestic sources, Access Northeast's integrated natural gas pipeline and storage solution is regional in scale and scope and delivers natural gas on a firm basis the full length of the system (including the last mile) directly where it is desired to be delivered to electric power generators. Additionally, service under Access Northeast's Rate Schedule ERS is designed to meet the operational requirements of natural gas-fired electric generators. For example,

[7] Joint Testimony of Timothy J. Brennan and John E. Allocca, at 38.
[8] Joint Testimony of Timothy J. Brennan and John E. Allocca, at 44.

> shippers under Rate Schedule ERS will have the right to firm capacity reserved for their needs on a 24-hour basis, with firm non-ratable delivery rights as a result of the integrated LNG storage facility, and the right to a firm quick-start capability without a corresponding receipt point nomination for up to two hours.
>
> By integrating LNG storage into its service proposal, Access Northeast can provide power generators with a no-notice, quick-start fuel supply when renewable resources are not generating due to the intermittent and unpredictable nature of those resources; thereby, enhancing renewable capability and development consistent with key public policy goals.[9]

C. The Company's response to Data Request McKEE-GRID 1-2 explains that the net benefits projected from the Proposed Agreement for Rhode Island electricity customers do not assume any revenue at all from resale of the Access Northeast capacity. That is, the Company's economic benefit-cost analysis prepared by Black & Veatch Management Consulting LL C (Black & Veatch) demonstrates substantial net economic benefits for Rhode Island customers even before taking into account the anticipated revenue from resale of the Access Northeast capacity to electricity generators.

In addition, as explained in Exhibit DPU-ANE-3-3 filed by the Company's Massachusetts affiliates with the Massachusetts Department of Public Utilities in D.P.U. 16-05:

> Given the uncertainty of the factors that will determine the value of any sales of LNG and the overall capacity release, National Grid has not projected the value of LNG sales or capacity release revenue during the term of the agreement as it does not believe that they can be accurately predicted.

[9] Attachment McKee 1-12 (D.P.U. 16-05, Exhibit ALGONQUIN-RJK-1), at 15-16.

> Some of the main variables that will impact the market revenues for LNG sales and the overall capacity release include: the amount of capacity that is ultimately built in New England; the impact of weather variations; and the amount of LNG imported to New England. Colder than normal weather provides the opportunity to generate greater revenues and margins, but even when weather averages to be normal, weather with greater variations can generate greater revenues and margins than normal weather with lesser variability. For example, the winter period could have normal temperatures for an entire winter period but have some very cold days (which generate high margins) as well as much warmer than normal weather with little to no margins. A normal period that includes some very cold weather with offsetting warmer periods would generate greater revenues and margins than a normal winter with less dramatic variability. The amount of imported LNG that is delivered to New England, which is a function of world market LNG prices relative to delivered gas prices in New England, will also impact revenues and margins. All of these factors will fluctuate each year depending on the particular circumstances at that time.[10]

D. See the response to part (B) above.

E. The Company's response to Data Request McKEE-GRID 1-2 explains why the premise that the Company and its customers will "go into business together" is false. As such, it is not accurate to think of "competitors" with "pricing strategies" as one might for a competitive business. Nonetheless, the Company did consider alternatives to the proposed agreement for capacity on the ANE Project. The Joint Testimony of Timothy J. Brennan and John E. Allocca (at 52-59) explains how the Company issued a request for proposals (RFP) to solicit proposals for interstate capacity/gas supplies to further the

[10] A copy of this exhibit was provided in response to Data Request PUC 1-1.

goals of reduction of the cost of electricity and increasing the reliability of the New England electric system to benefit electric distribution 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. Schedule GJW-1 and Schedule GJW-3 demonstrate that, given the respective contract costs and electricity market benefits of the ANE Project and competing RFP bids, the Proposed Agreement provides the greatest net economic benefits to New England and to Rhode Island electricity customers.

Prepared by or under the supervision of: Timothy J. Brennan

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 16-05

REBUTTAL TESTIMONY OF RICHARD J. KRUSE

ON BEHALF OF

ALGONQUIN GAS TRANSMISSION, LLC

JULY 11, 2016

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Richard J. Kruse. My business address is 5400 Westheimer Court, Houston, TX 77056-5310.

Q. By whom are you employed and in what position?

A. I am Vice President, Regulatory and Federal Energy Regulatory Commission ("FERC") Compliance Officer for Algonquin Gas Transmission, LLC ("Algonquin"). I hold similar positions in the other interstate natural gas pipelines owned and operated by Spectra Energy Partners LP ("Spectra Energy"), including two interstate pipelines–Texas Eastern Transmission, LP ("Texas Eastern") and Maritimes & Northeast Pipeline, LLC ("Maritimes")–which deliver natural gas to Algonquin. I am responsible for the development and management of Spectra Energy's regulatory strategy with FERC and in state proceedings in each of the states served by Spectra Energy's pipelines. I am responsible for managing the company's involvement in the North American Energy Standards Board ("NAESB"). I also serve on the NAESB Board of Directors.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Economics from Texas Tech University and a law degree from the University of Houston. I joined Texas Eastern in 1977 as an analyst in Houston, Texas. After a series of promotions, I was named Assistant General Counsel for Texas Eastern in 1988, Deputy General Counsel of Regulatory Operations for Texas Eastern and Algonquin in 1990, Vice President and General Counsel for Texas Eastern in 1992, and Associate General Counsel for PanEnergy Corp in 1995. Following the merger of PanEnergy Corp and Duke Energy, I was named Vice President and General Counsel of Gas Operations for Duke Energy in 1997, Vice President and General Solicitor in 1998, and Senior Vice President of Projects and Utility Initiatives in 1999. Prior to the spin-off of Spectra Energy from Duke Energy, I was Vice President of Rates and Regulatory Affairs for Duke Energy Gas Transmission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to portions of the testimony submitted on behalf of the Massachusetts Attorney General, Conservation Law Foundation, NextEra Energy Resources, LLC ("NEER"), Repsol Energy North America Corporation, and Direct Energy Business, LLC and Direct Energy Services, LLC (collectively, "Intervenor Testimony"). In particular, this testimony will address claims made in Intervenor Testimony regarding: (a) the need for and purpose of the Access Northeast Project ("Access Northeast"); (b) the availability of natural gas for transportation as a result of Access Northeast; and (c) the claimed viability of imported liquefied natural gas ("Imported LNG") supply as an alternative to Access Northeast.

II. THERE IS A PURPOSE AND NEED FOR ACCESS NORTHEAST

Q. What is your response to claims that Access Northeast is not necessary to ensure electric reliability?

A. ISO New England Inc. ("ISO-NE") has found that "[t]he region's reliance on the natural gas fuel-delivery system . . . continuously exposes the regional electric power system to potential reliability problems and an associated increased cost of electricity when natural gas prices are high. This is the result of limited gas pipeline capacity in New England[.]"[1] Thus, ISO-NE has made it clear that "pipeline development is out of step"[2] and that "ultimately, improving the natural-gas-delivery infrastructure in New England ... will have the most impact on addressing the reliability, price volatility, and negative emission impacts during winter."[3] The New England Governors recognized this problem several years ago and released in 2015 a six-state action plan, in which the governors advised "that the region's economy is limited by existing natural gas pipeline capacity" and expressed their support for "regional efforts to expand natural gas capacity into New England to address reliability risks to the electric system and price impacts on electric consumers during the winter period."[4] Nearly all New England states are conducting proceedings to evaluate proposals to fund needed pipeline

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[1] ISO-NE, 2015 Regional System Plan (Nov. 5, 2015) ("ISO-NE 2015 Regional System Plan"), at 9.

[2] *See, e.g.*, ISO-NE, 2016 Regional Electricity Outlook (Mar. 2016) ("ISO-NE 2016 Electricity Outlook") (available at http://www.iso-ne.com/static-assets/documents/2016/03/2016_reo.pdf), at 14.

[3] *Id.* at 3-4.

[4] New England States Committee on Electricity ("NESCOE"), Governors' Actions for a Cleaner, More Reliable, and More Affordable Energy Future (Apr. 23, 2015) (available at: http://nescoe.com/resources/govs-actions-apr2015/).

expansion through the electric distribution companies' ("EDCs") retail electric rates. Further, ISO-NE has determined that, even after implementing changes to the market rules to encourage generators to ensure firm gas supply, "[u]ltimately, it will take natural gas infrastructure improvements—some combination of pipeline, liquefied natural gas, and storage solutions— to address both reliability risks and price volatility."[5]

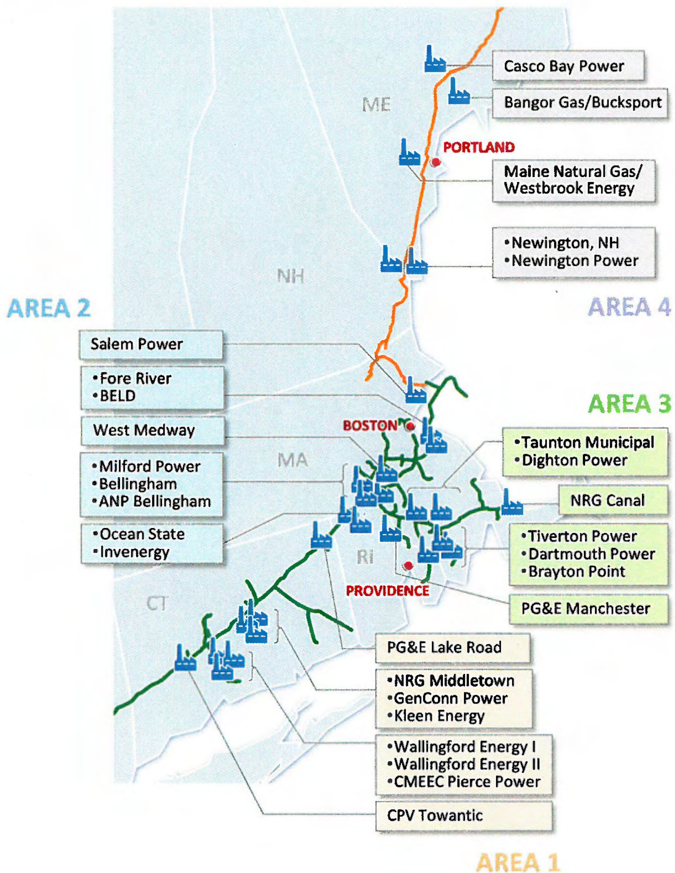
Q. What role does Algonquin play in delivering natural gas to electric generators in New England?

A. Algonquin's system is the primary natural gas delivery infrastructure for providing natural gas to electric generators in New England. Algonquin alone serves 44% of the natural gas-fired electric generators in New England and, when combined with Maritimes, serves approximately 60%. The natural gas-fired electric generators already connected or anticipated to be connected to Algonquin or Maritimes are shown in Figure 1. Directly connected power generator capability currently served by Algonquin and Maritimes is estimated to be nearly 9,500 megawatts ("MW").

[5] ISO-NE 2016 Electricity Outlook, at 14.

D.P.U.: 16-05
EXHIBIT: ALGONQUIN-RJK-1
DATE: JULY 11, 2016
H.O.: DAVID GOLD

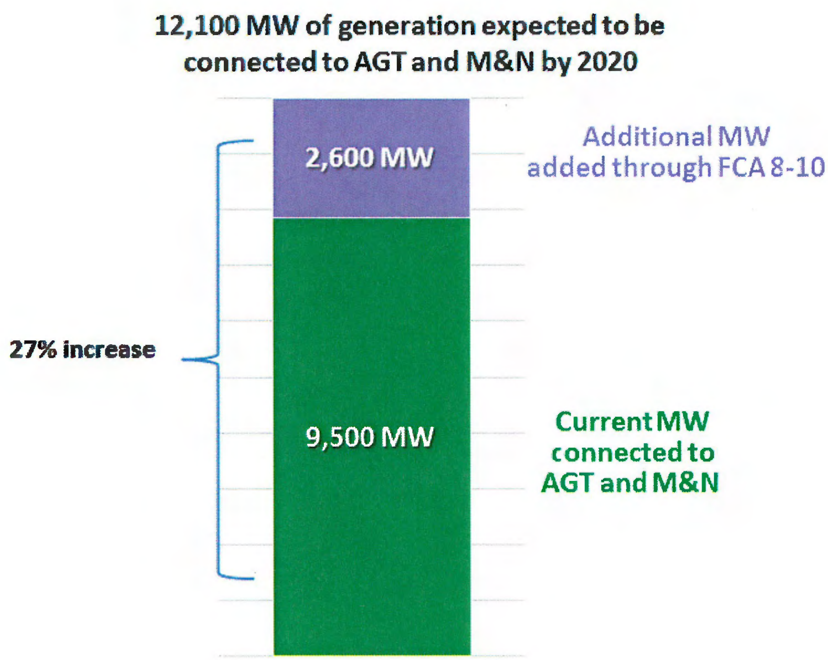
Figure 1: Directly-Connected Natural Gas-Fired Generators on Algonquin and Maritimes



By 2020, approximately 2,600 MW of additional generation is expected to be directly connected to Algonquin, including six plants that cleared the 2017, 2018 and 2019 ISO-NE capacity auctions (CPV-Towantic (785 MW), Salem Power (674 MW), West Medway (200 MW), Wallingford (100 MW), Burrillville

Energy Center/Invenergy (485 MW) and Canal (333 MW)).[6] These additional plants represent a 27% increase of natural gas-fired generators directly connected to the Algonquin and Maritimes systems.

Figure 2: New England Power Plants by Pipeline by 2020, Including Forward Capacity Auction 10 Cleared Plants



Because of the importance of Algonquin, the expansion of Algonquin's pipeline system through Access Northeast is an effort by Algonquin to address the reliability, price volatility and emissions concerns, that ISO-NE, the New England Governors, state legislatures and commissions, and EDCs have identified.

[6] *See* ISO-NE Forward Capacity Market Auction Results (available at: http://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-auction-results).

Q. How would you respond to the claim that Access Northeast is not needed?

A. When 60% (and growing) of the natural gas-fired generation fleet is attached to a constrained natural gas pipeline that, as I will demonstrate in my testimony, cannot consistently flow the non-firm transportation services that most generators use, the best way to increase reliability in the region is to make firm transportation capacity available through an expansion of that pipeline.

Q. What is the connection between firm and non-firm transportation contracts and pipeline capacity constraints?

A. Pipeline capacity constraints exist when non-firm customers attempt to transport natural gas on a non-firm basis at the same time that firm customers are utilizing their own firm capacity rights. A non-firm customer is much like an airline passenger flying standby and hoping to get a seat. Interstate pipelines are designed to provide service to meet firm service obligations as reflected in firm transportation contracts. Non-firm service means that natural gas is being received and/or delivered at points on Algonquin or Maritimes other than the points contracted for firm service. Interstate pipelines make no commitments as to the availability of such non-firm service. Until actually scheduled and confirmed on any given day by the pipeline, non-firm service has a lower priority of service than firm contracts. Thus non-firm service is subject to interruption in order for the pipeline to provide service to customers under firm contracts. While many industry people refer to "secondary" as firm because it is a derivative right of firm service, it is extremely important to remember that "secondary" nevertheless is a non-firm service and subject to interruption until scheduled on any given day. Accordingly, for purposes here, I only make the distinction between firm and non-firm pipeline capacity contracts. As shown in Figure 3 below, the vast majority of natural gas-fired generators on Algonquin receive delivered gas from non-firm contracts. Less than 500 MW of the currently connected 9,500 MW on Algonquin and Maritimes are served by pipeline contracts that provide firm mainline transportation paths directly to generators. This means that 95% of the natural gas-fired generators currently rely upon non-firm pipeline capacity.

Figure 3: System Electric Generator Priority of Service

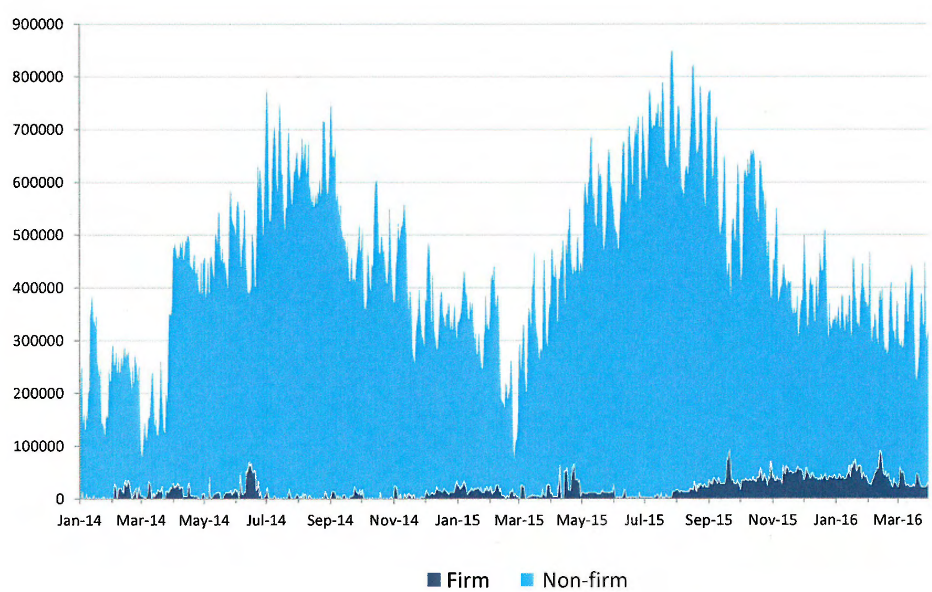
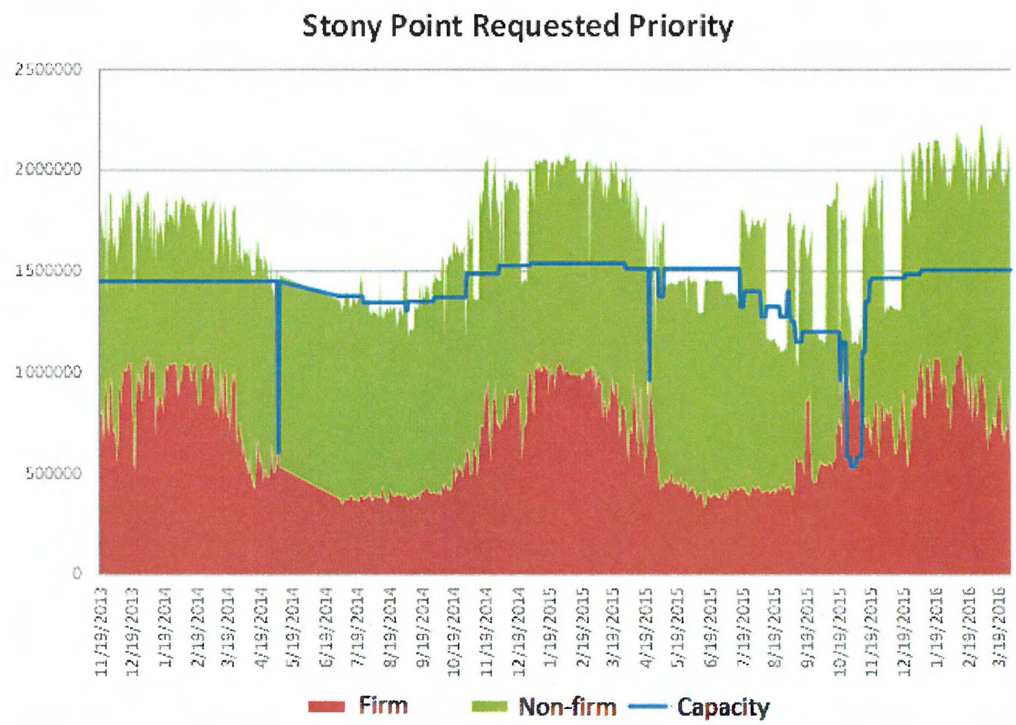


Figure 4 depicts the quantities of gas nominated to flow west to east sorted by firm and non-firm volumes through the Stony Point compressor station for the time period from November 19, 2013 through March 19, 2016. Algonquin is consistently nominated at levels much greater than the capacity through Stony Point and there is a significant amount of nominations under non-firm capacity by shippers trying to get through this highly constrained area of the pipeline. Figure 4 shows that significant volumes of gas during the winter months are simply not getting scheduled because the amount of unscheduled gas increases as firm customers use their higher-priority firm pipeline capacity rights. Furthermore, even when some non-firm transportation is moving through the constraint point on any given day, the primary firm contract holder contractually controls the capacity such that non-firm is exposed to interruption on any subsequent day.

Figure 4: Stony Point Requested Priority



Q. Has the quantity of natural gas sought by natural gas-fired generators increased over time?

A. Yes, as shown in Table 1, the quantity of gas scheduled for delivery during the November through March time period ("Winter") to natural gas-fired generators has grown from an aggregate quantity of 23,920,920 dekatherms ("Dths") in the 2006/2007 Winter to 74,681,461 Dths in the 2015/2016 Winter (an increase of 212%). However, the amount of natural gas which generators nominated, but which was not scheduled for delivery by the pipeline due to pipeline constraints has also grown significantly. Over the last three years, a staggering amount of natural gas sought by natural gas-fired generators has not been able to be delivered due to capacity constraints. In fact, nearly ***1 out of every 2 Dths*** of natural gas nominated to be delivered to natural gas-fired generators was not scheduled due to capacity constraints.

Table 1: Natural Gas-Fired Generator Nominations During Winter

Winter (Nov – Mar)	Nominated Volume	Scheduled Volume	Unscheduled Volumes	% Unscheduled
2006 / 2007	24,105,810	23,920,920	184,890	1%
2007 / 2008	26,804,047	26,440,648	363,399	1%
2008 / 2009	26,602,986	26,219,506	383,480	1%
2009 / 2010	36,705,083	35,703,669	1,001,414	3%
2010 / 2011	44,039,452	42,220,887	1,818,565	4%
2011 / 2012	96,167,019	63,521,140	32,645,879	34%
2012 / 2013	90,542,902	54,065,566	36,477,336	40%
2013 / 2014	100,217,122	53,185,859	47,031,263	47%
2014 /2015	102,565,643	54,572,354	47,993,289	47%
2015 / 2016	147,594,358	74,681,461	72,912,897	49%

By way of one specific example, of many, on February 15, 2015, the total nominated volume for the natural gas-fired generators on the G-system of Algonquin was 177,221 Dths. However, even though the full 177,221 Dths would have arrived at the head of the G-system, due to restrictions on the G-system, the amount scheduled was actually 23,237 Dths—an 87% reduction in requested deliveries.

Q, **How has this increased demand placed on Algonquin impacted operations of the system?**

A. Algonquin has been operating at the operational limits of its pipeline system much more often, and consequently the frequency of critical notices has also increased dramatically. EXHIBIT ALGONQUIN-RJK-2 includes a copy of all "Critical Notice" postings for the period of 02/01/2015 to 02/28/2015, which shows the types of restrictions Algonquin places on nominations during times of constraints. As the postings demonstrate, there are multiple restrictions during every day of the month that cover mainline, lateral and receipt point constraints. This one month is illustrative of the types of notices being issued with much greater frequency in recent years as a result of increased competition between firm and non-firm shippers.

Q. **Can you elaborate on Algonquin's experience with the contracting practices of electric generators?**

A. Yes. Notwithstanding the generators' inability to schedule transportation service during peak periods, generators have contracted for limited firm mainline capacity. Algonquin has held multiple open seasons to expand its mainline capacity in the last several years through its Algonquin Incremental Expansion, Atlantic Bridge and Access Northeast projects. In each of these instances, generators have not contracted for firm mainline capacity to bring natural gas to their generation plants in New England.

Q. How would you respond to the contention that generators do not want or need firm natural gas transmission capacity?

A. Given the structure of the wholesale electric market in New England, my experience is that individual generators have little if any economic incentives to sign contracts for firm natural gas pipeline capacity. Indeed, New England consumers and electric ratepayers will be the primary beneficiaries of increased natural gas pipeline infrastructure dedicated to serve the needs of the electric industry.

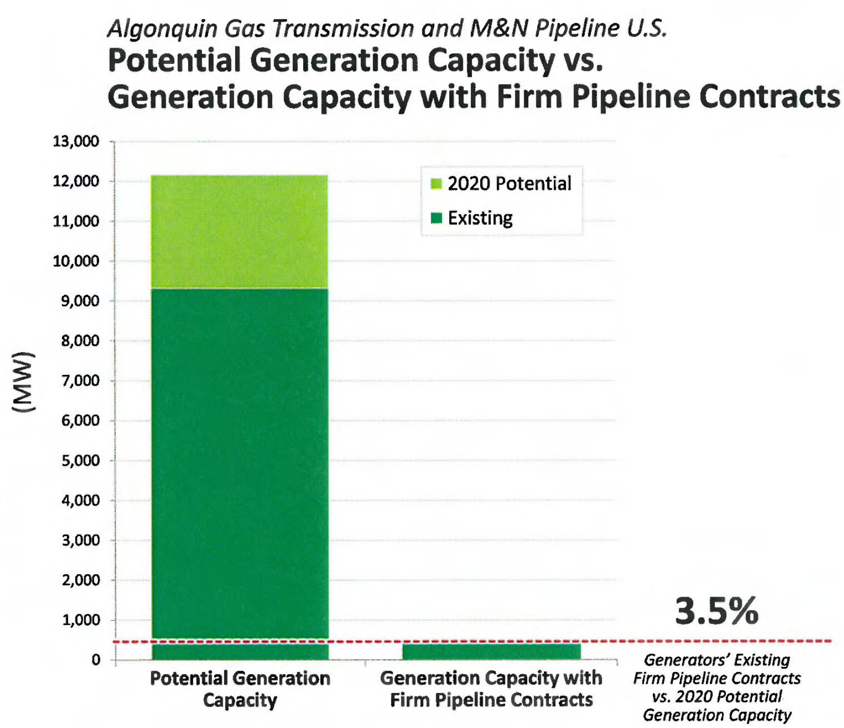
Q. What is your response to claims by NEER that the Bellingham plant has not had difficulty securing fuel in the winter months?

A. While I do not know all the details of Bellingham transportation arrangements for getting fuel, I do know that the Bellingham plant has limited firm contractual delivery rights to the plant that are only a small fraction of the overall plant's capability. I would assume, based on those limited firm contractual rights, that all other volumes scheduled to the plant have been on a non-firm basis. As a result, even though Bellingham may have been able to secure natural gas on Algonquin's system in the past, we cannot be assured that Bellingham will be able to do so in the future given the lack of firm natural gas pipeline capacity commitments.

Q. What do capacity constraints and the use of non-firm pipeline capacity contracts mean for electric reliability in New England?

A. Absent changes in contracting behavior by the generators, which Algonquin has not seen, or provision of firm service to generators by another means such as that being offered through Access Northeast, only 3.5% of natural gas-fired generation connected to Algonquin in 2020 will have assured fuel delivery pursuant to a firm transportation contract on Algonquin. *See* Figure 5. In my opinion, this presents a significant risk for electric reliability.

Figure 5: Natural Gas-Fired Power Generation Capacity Fueled by Firm Transportation Contract



This lack of firm pipeline capacity for generators has become even more of an electric reliability concern as New England has become increasingly reliant on natural gas-fired generation—i.e., while natural gas fueled just 15% of the region's electricity in 2000, ISO-NE now gets over 50% of its power from natural gas. Even without the retirement of the Pilgrim nuclear generating facility, ISO-NE predicts that natural gas will represent nearly 57% of generation by 2024, compared with 44% in 2015.[7] However, without firm commitments for transportation capacity to those plants, there can be no confidence that these plants will be able to obtain the natural gas they need to run when they are needed most by ISO-NE.

Q. Does Access Northeast do anything other than resolve capacity constraints?

A. Absolutely. Not only is Access Northeast the only solution that will provide the majority of New England's natural gas-fired generators with firm, reliable, direct access to natural gas supply from diverse, domestic sources, Access Northeast's integrated natural gas pipeline and storage solution is regional in scale and scope and delivers natural gas on a firm basis the full length of the system (including the last mile) directly where it is desired to be delivered to electric power generators. Additionally, service under Access Northeast's Rate Schedule ERS is designed to meet the operational requirements of natural gas-fired electric generators. For example, shippers under Rate Schedule ERS will have the right to firm capacity reserved for their needs on a 24-hour basis, with firm non-ratable delivery rights

[7] ISO-NE 2015 Regional System Plan, at 127.

as a result of the integrated LNG storage facility, and the right to a firm quick-start capability without a corresponding receipt point nomination for up to two hours.

Q. How would you respond to the assertion that, rather than investing in natural gas infrastructure, the region should invest in more renewables?

A. The two need not be mutually exclusive. New variable-output renewable electric generation capacity under development in New England will require the support of new natural gas-fired projects "to provide operating reserves as well as other ancillary services, such as regulation and ramping."[8] By integrating LNG storage into its service proposal, Access Northeast can provide power generators with a no-notice, quick-start fuel supply when renewable resources are not generating due to the intermittent and unpredictable nature of those resources; thereby, enhancing renewable capability and development consistent with key public policy goals, such as the state greenhouse gas emissions reductions goals set forth in the Massachusetts Global Warming Solution Act.

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[8] ISO-NE 2015 Regional System Plan, at 185.

III. THE INTERVENOR TESTIMONY MISCONTRUES THE AVAILABILITY OF NATURAL GAS TRANSPORTATION FROM ACCESS NORTHEAST

Q. What is your response to the claim that Access Northeast will not provide a new source of supply?

A. The challenges facing New England are not attributable to a shortage of supply, but rather the lack of pipeline infrastructure to deliver available supplies to the burner tip market. Referring again to Table 1 above, significant quantities of gas were available into Algonquin, but remained unscheduled due to pipeline constraints on Algonquin. But for these constraints, which would be removed by Access Northeast, an average of approximately 483,000 Dths/day of ***additional*** natural gas could have been scheduled to serve New England's natural gas-fired generators during the 2015/2016 Winter. Clearly, the existing sources of supply to Algonquin are already robust. This supply is made available as a result of interconnects with pipelines operated by Texas Eastern, Tennessee Gas Pipeline, Columbia Gas Transmission Corporation, Iroquois Gas Transmission System, Maritimes, Millennium Pipeline Company, LLC, and Transcontinental Gas Pipe Line Corporation. Currently, the delivery capability of these upstream pipelines into Algonquin significantly exceeds Algonquin's pipeline takeaway capacity. Getting natural gas to the Algonquin system is not a problem; getting natural gas ***through*** constraint points on Algonquin is a problem.

Q. Why are claims that there is insufficient liquidity at Access Northeast receipt points to provide 900,000 Dths/day incorrect?

A. These claims are incorrect because they are based on the mistaken premise that Algonquin is proposing to expand its pipeline capacity to move ***900,000 Dths/day*** of incremental gas from receipt points in the west end of Algonquin's pipeline system. What Algonquin actually is proposing to do is to expand its pipeline capacity to move ***500,000 Dths/day*** of incremental natural gas from receipt points in the west end of Algonquin's pipeline system coupled with ***400,000 Dths/day*** at the Access Northeast LNG storage facility. In non-peak periods, 500,000 Dths/day of pipeline capacity will be available to meet the needs of the generators, but will also be used to transport west end supplies to fill or refill the Access Northeast LNG storage facility where the natural gas will be stored and then withdrawn at a maximum daily rate of up to 400,000 Dths/day when needed during peak periods. Thus, during peak periods, generators will have access to 900,000 Dths/day of firm capacity (500,000 Dths/day from the west end and 400,000 Dths/day from the Access Northeast LNG storage facility). As I discussed in the preceding question, nominations to serve power plants during peak periods over the last three years confirm there is sufficient natural gas supplies to fill the additional 500,000 Dths/day of capacity from the west end. Again, getting natural gas to Algonquin is not the problem, getting natural gas through constraint points on Algonquin is the problem. Accordingly, claims of insufficient west end liquidity are mistaken and suggest a misunderstanding or mischaracterization of the Access Northeast project.

IV. IMPORTED LNG SUPPLY IS NOT AN ADEQUATE SUBSTITUTE

Q. How would you respond to claims that Imported LNG is a better alternative to Access Northeast (i.e., why can't LNG supply on the east-end of the Algonquin system resolve New England's reliability concerns)?

A. Without firm capacity enhancements to create a firm transportation path to the generators on Algonquin and Maritimes, even if Imported LNG supply is available, delivery to these natural gas-fired generators will be non-firm and thus subject to interruption. See by way of example the discussion above on pages 10-11 regarding constraints on Algonquin's G-system. As such, an expansion of the existing system still would be necessary to get the natural gas to markets on Algonquin. Since pipelines design their systems based on firm commitments, such an expansion would require the Imported LNG suppliers to enter into firm contracts for delivery to natural gas-fired generators, which they have yet to do on the Algonquin system. In addition to securing pipeline capacity, Imported LNG solutions would need the capacity reservation and flexible character of service of Rate Schedule ERS proposed in Access Northeast. Unless Imported LNG suppliers commit to provide firm delivery capacity on Algonquin directly to the generators, any comparison of Access Northeast to Imported LNG is an apples-to-oranges comparison, and an inappropriate comparison.

Q. To be clear, do any Imported LNG suppliers on the east end of Algonquin's system have firm capacity commitments on Algonquin?

A. Yes. But there is a very important point to make here. Although certain of these Imported LNG facilities do have firm contracts on Algonquin, the volumes contracted for on a firm basis are very limited, and any additional service to generators under these contracts would be non-firm and thus subject to interruption.

Q. Does Imported LNG and operation of dual-fuel generating units operating on oil solve any "problem"?

A. If the problem New England is attempting to solve is the availability or price of natural gas and the resulting price of electricity during the Winter, Imported LNG resources did not solve the problem despite having been available during the Winters of 2013/14 and 2014/15. Moreover, it is not clear how these resources will solve the problem going forward. As discussed above, Imported LNG can perhaps solve the supply problem (but not necessarily the price problem due to the fact that Imported LNG is traded globally) *only if* pipeline infrastructure is available to deliver to natural gas-fired generators on a firm basis and right now that is not the case. In severe weather conditions, generators also may not be able to receive oil deliveries; thereby, making the ability of dual-fuel generating units to operate on oil uncertain as well. Even if oil were available, as discussed in the accompanying testimony of Kristine Kramer of Wood Mackenzie, running generators on oil instead of gas increases emissions, which is inconsistent with the Massachusetts Global Warming Solutions Act.

V. CONCLUSION

Q. Do you have any closing remarks?

A. Yes. It is well documented that the lack of adequate natural gas pipeline infrastructure to supply regional power generation has resulted in higher electric prices paid to New England generators by New England consumers and ratepayers. Experience also demonstrates that, when the weather turns cold in New England (and winter comes every year), Algonquin will not, absent an expansion of this constrained pipeline, be able to meet the service needs of natural gas-fired generators under non-firm contracts. And this deficit in capacity availability exists on a pipeline where only 3.5% of natural gas-fired generators will hold firm contracts by 2020, yet in a region where natural gas-fired generators will account for 57% of the total ISO-NE generation mix by approximately the same timeframe creating valid reliability concerns. The idea that simply securing Imported LNG supply will solve the problem is ill-founded because this approach would increase Algonquin's firm delivery capability to power generators by exactly ZERO, unless it is coupled with an expansion of Algonquin and supported by firm transportation contracts. Without firm transportation capacity, Massachusetts (and the New England region) cannot rely on the presumption that natural gas will be available to generators on peak day.

Q. Does this conclude your testimony?

A. Yes.

McKEE-GRID 1-13

Request:

In its response to PUC 1-10, National Grid shows the total cost of the ISO NE electric energy market for the historic winter periods beginning with 2011/12 and ending with 2015/16.

A. For the Black & Veatch analysis described in Schedule GJW-3, what is the total projected cost of the ISO NE electric energy market for future winter periods year by year (2016-17 through 2037-38)?

B. Please provide two sets of costs, one for the Reference case (without the ANE project) and another for the Reference case with the ANE project.

Response:

a-b) Please see Attachment McKEE-1-13 (Highly Sensitive Confidential Information) for the projected annual winter (December through February) energy electric costs from 2019-2038 for the Reference Case and With ANE scenario.

Prepared by or under the supervision of: Denny K. Yeung and Gary J. Wilmes

REDACTED

New England Winter Electric Energy Costs (2015$M)

Column	A	B	C
Line #	Year	Reference Case	With ANE
1	2019	[redacted]	
2	2020		
3	2021		
4	2022		
5	2023		
6	2024		
7	2025		
8	2026		
9	2027		
10	2028		
11	2029		
12	2030		
13	2031		
14	2032		
15	2033		
16	2034		
17	2035		
18	2036		
19	2037		
20	2038		

McKEE-GRID 1-14

Request:

Referring to Schedule GJW-1, please prepare a new Sensitivity Reference Case making the following different assumptions and show the cost-benefit results:

A. In the Reference Case (without the ANE project), please include all of the following:

   1. The Gulf Suez and Repsol LNG projects as specified in Table 2 of Schedule GJW-3; and

   2. The renewable hydro-electric imports (1,090 MW capacity) and incremental wind generation (1,200 MW) as specified in Table 3 of Schedule GJW-3; and

   3. Having new dual fuel generation capacity in New England come on line in New England to replace economically-driven capacity retirements in New England (See Pages 12-13 of the B&V report, Schedule GJW-3)

B. In this Sensitivity Reference Case with ANE:

   1. Add in 1,500 MW of additional natural gas-fired new generation to represent the replacement of the additional non-gas-fired generation that will be retired because of the price suppression in the electric wholesale price without a corresponding reduction in production costs.

C. Only count 10 years of benefits to reflect the uncertainty that they will occur (since there is no guarantee to ratepayers).

D. Use a higher discount rate for benefits of 9% to reflect ratepayer risk.

E. Assume that there are cost overruns up to the cap.

Response:

It is Black & Veatch's expert opinion that the suggested assumptions referenced above for the new Sensitivity Reference Case are unrealistic and do not warrant additional economic analysis. The new proposed Sensitivity Reference Case does not appropriately take into consideration the proposed costs of the GDF Suez and Repsol LNG projects, which are provided in Schedule

GJW-3, Table 7. The LNG import volumes and associated costs from these alternative projects would need to be included in both the new Sensitivity Reference Case and With ANE scenario for a proper cost benefit analysis. Without firm sales contracts, the assumed incremental import volumes at Everett and Canaport LNG terminals would be highly speculative in nature, which would impact the net benefits analysis.

It is also Black & Veatch's expert opinion that all benefits over the twenty year contract period of 2019-2038 should be included in the cost-benefit analysis. The arbitrary counting of 10 years of benefits is unsupported.

McKEE-GRID 1-15

Request:

Referring to Table 4 of Schedule GJW-3 on page 25, what is the level of average monthly winter basis reduction, in $/MMBTU, that National Grid is prepared to guarantee to its electric distribution ratepayers?

Response:

The Company has not proposed to guarantee a certain level of benefits or related outcomes with respect to the ANE Project. The Company's response to Data Request McKEE-GRID 1-3 discusses the matter of guaranteed outcomes related to the ANE Project in more detail.

McKEE-GRID 1-16

Request:

Referring to Figure 10 of schedule GJW-3 on page 25, what is the average annual electric price reduction, year by year, attributable to the ANE project, in $/MWh, that National Grid is willing to guarantee for its ratepayers?

Request:

The Company has not proposed to guarantee a certain level of benefits or related outcomes with respect to the ANE Project. The Company's response to Data Request McKEE-GRID 1-3 discusses the matter of guaranteed outcomes related to the ANE Project in more detail.

Prepared by or under the supervision of: Timothy J. Brennan and John E. Allocca

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McKEE-GRID 1-17

Request:

Is there a percentage of the gas transportation capacity in the ANE project that National Grid can guarantee will be used by gas-fired electric generators in New England? What is that percentage?

Response:

The Company has not proposed to guarantee a certain level of benefits or related outcomes with respect to the ANE Project. The Company's response to Data Request McKEE-GRID 1-3 discusses the matter of guaranteed outcomes related to the ANE Project in more detail.

McKEE-GRID 1-18

Request:

Please provide a list of the owners of gas-fired electric generation in New England who have testified in favor of the ANE project, either at FERC or before any of the New England state regulatory authorities.

Response:

The Company is not aware of any owners of gas-fired electric generation in New England who have testified in favor of the ANE Project. However, this should not be taken as an indication that there is an adequate supply of natural gas transportation. The Joint Testimony of Timothy J. Brennan and John E. Allocca (at 16-21) explains the high and volatile natural gas and electricity prices and excessive costs imposed on New England and Rhode Island electricity customers as a result of constrained natural gas transportation capacity. Nor should one interpret the lack of testimony in support of the ANE Project from gas-fired generator as an indication that they will not avail themselves of the services offered by the ANE Project. As the Company described in its response to Data Request McKEE-GRID 1-12, the ANE Project is designed to serve the majority of gas-fired generators in New England, and its Rate Schedule ERS is tailored specifically to the needs of gas-fired generators.

Dr. Charles Cicchetti—the co-founder and President of Pacific Economics Group, Inc., and an economist with nearly 50 years of experience in the electricity industry—has provided his expert opinion regarding the incentives and motivations of the owners of gas-fired electric generation in New England with regard to the ANE Project:

> Electric generators in ISOs/RTOs bid into and sell their electricity in competitive wholesale markets and, by and large, are paid a "market-clearing price." These generators compete and operate under a business model and regulatory construct that encourages them primarily to focus on short-run marginal cost and take the prevailing market price of fuel as a given. It is reasonable to expect these generators to bid to sell their electricity at their respective, specific short-run marginal cost. If fuel prices change, all competitive generation using that fuel would experience a similar change in their respective short-run marginal cost in proportion to the amount of fuel burned to produce electricity.

> Electricity generators in New England and other ISO/RTO markets reasonably glean from the market that when their fuel costs increase or decrease, other competitors using the same fuel to generate electricity would experience the same price changes. Thus, a generating unit's ranking in the supply to the wholesale market depends on its respective heat rate, and not the price of natural gas that each competitive natural gas-fired electric generator must pay. Accordingly, price increases in natural gas increase a unit's short- run marginal cost and directly affect the bids and the resulting market-clearing prices for wholesale electricity generally.
>
> <u>Electric generators have no incentive to eliminate the pipeline constraints that lead to higher and more volatile natural gas prices in New England.</u> Electric generators that burn only natural gas have little individual economic incentive to hedge or otherwise insulate themselves from the adverse effects of the virtually certain natural gas price volatility and price surges in the cold-weather months because the market-clearing price will always allow them to recover their marginal costs. Additionally, electricity generators who own inefficient coal-fired units may find these otherwise un-economic units in the money during periods with natural gas scarcity and/or high and volatile natural gas prices. Similarly, some generators that can burn either fuel oil or natural gas may find they are more likely to be in the money to sell electricity using fuel oil. Accordingly, <u>owners of generation who are more likely to sell electricity during constrained natural gas supply months have no incentive to invest in infrastructure necessary to relieve natural gas supply shortages. Instead, they would tend to benefit if these constraints remain.</u>[1]

Corroborating Dr. Cicchetti's diagnosis of the lack of vocal support from gas-fired generators for the ANE Project, a research note published by equity analysts at UBS Investment Research regarding the Massachusetts Supreme Judicial Court's decision that led the Company's affiliates to withdraw their application for approval of contracts with the ANE project by the Massachusetts Department of Public Utilities said:

[1] Affidavit of Charles J. Cicchetti, Exhibit A to Algqonquin Gas Transmission LLC's Answer in Opposition to Complaint in Federal Energy Regulatory Commission Docket No. EL16-93-000 (emphasis added), at 4-6.

> **Positive for New England generators**
>
> We see the latest developments as quite constructive for IPPs [independent power producers] regionally, including not just the baseload folks including particularly Dominion, but also NextEra as well given their exposure via baseload nuclear plants. The baseload exposure of Millstone had driven substantial pressures on [Dominion's] consolidated results as hedges materially fell off. We also see the delayed gas supply expansons [sic] as broadly constructive for even gas CCGTs [combined cycle gas turbine power plants] given the largely gas-on-the-margin market makes even spark linked to gas.[2]

In another recent research note, UBS Investment Research, with respect to NextEra Energy Resources, LLC and Public Service Enterprise Group Inc. (PSEG), commented on the motivations of electricity generation owners with respect to the ANE project:

> [T]he complaint [filed at FERC by NextEra Energy Resources, LLC, and PSEG Companies against ISO-NE regarding the ANE Project] demonstrates the level of commitment from generators to maintain status quo for pipeline capacity and by extension, energy pricing.[3]

The Proposed Agreement, in contrast, is projected to lower energy pricing and deliver levelized annual net economic benefits to Rhode Island electricity customers of $0.11 billion per year over the life of the contract when compared to a "status quo" scenario without the ANE project (see Schedule GJW-3, Table 8).

[2] UBS Investment Research, "Eversource Energy: Denied by Supreme Court" (August 18, 2016).

[3] UBS Investment Research, "US IPP Weekly Power Points: The Conference Skinny" (September 6, 2016).

McKEE-GRID 1-19

Request:

On page 72, lines 14-18 of their direct testimony, Mr. Brennan and Mr. Allocca state that the electric ratepayers will still receive benefits even if the capacity releases go to other parties besides the gas fired electric generators. However, the ratepayers will not receive benefits to the same extent as with priority release to generation first.

A. Has Black & Veatch analyzed that sensitivity case?

B. What were the results in terms of cost-effectiveness of the project?

C. If not, please complete that analysis and provide the results in a format that matches Schedule GJW-1.

Response:

The Black & Veatch analysis was based on the forecasted supply and demand balance as it relates to natural gas and associated firm transportation capacity into the New England region. The New England natural gas demand is driven by local distribution company (LDC) demand growth and the region's growing dependence on gas-fired generation for the production of electricity. The Black & Veatch analysis is based on LDC demand growth continuing to be met with capacity projects supported by the LDCs. As Black & Veatch stated in Schedule GJW-3 at page 16:

> 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.

Thus, the Black & Veatch analysis of projected benefits for the ANE Project did not require, and was not dependent on the assumption of a particular capacity release approach. With the LDC demand fully served by its own firm capacity contracts, the incremental ANE Project capacity would be available and ultimately used as needed to serve the remaining demand in the region (the gas-fired generation demand), regardless of whether a priority release to generators was allowed. The potential for realizing different benefits if the proposed capacity was not released to generators on a priority basis could be imagined under a scenario in which the capacity was released and used by a new natural gas load not known to date. As it is not possible to forecast such an unknown demand, and as it is not possible to know whether this demand would contract for its own capacity, the analysis requested in part C cannot be completed.

Prepared by or under the supervision of: Stephen A. McCauley

McKEE-GRID 1-20

Request:

How confident are you that the hoped-for benefits to electricity ratepayers enumerated in the Black & Veatch report will materialize? 100%? 75%? 50%? 25% or 0%?

Response:

The Company has not assigned a numerical probability score to the projected net economic benefits enumerated in Schedule GJW-3. However, the Company is highly confident that the Proposed Agreement will deliver substantial net economic benefits for Rhode Island electricity customers.

The economic benefit-cost analysis presented in Schedule GJW-3 projects that the Proposed Agreement will deliver substantial net benefits to Rhode Island electricity customers under a range of scenarios, including substantial incremental clean energy generation over and above regional renewable portfolio standard targets. The Company and Black & Veatch Management Consulting, LLC (Black & Veatch) also took a conservative approach to modeling the economic impacts of the Access Northeast (ANE) Project versus the Reference Case—including the following assumptions: (a) electric and gas demand associated with normal weather, (b) regional pipeline capacity expansion to meet gas LDCs' design-day needs; and (c) compliance with regional renewable portfolio standards goals.

Moreover, the net economic benefits from lower future electric commodity costs presented by the Company in this proceeding are corroborated by the independent benefit-cost analysis of the ANE Project undertaken by ICF International (ICF) on behalf of Eversource Energy[1] in D.P.U. 15-181 before the Massachusetts Department of Public Utilities (see, e.g., Exhibit EVER-KRP-3 in that proceeding and provided as Attachment McKee-1-3). ICF's analysis for Eversource Energy illustrated how potential savings could be substantially higher than projected under a conservative set of modeling assumptions. Specifically, ICF modeled a sensitivity scenario that found that, "[a]ssuming design winter cold conditions, as well as a potential nuclear outage during the winter and higher power demand (ISO-NE's P90 demand forecast)," the ANE Project would yield annual savings for electricity customers that were 1.6 to 2.2 times greater than the average savings projected by ICF during normal years (see Attachment McKee-1-3 (D.P.U. 15-181, Exhibit EVER-KRP-3), at 7-8).

[1] NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy (Eversource Energy).

The arguments of certain parties opposed to the New England electric distribution companies' pursuit of contracts for incremental natural gas capacity themselves support the Company's analysis showing substantial electric commodity cost savings for customers. Specifically, in filing a Section 206 complaint before the Federal Energy Regulatory Commission (FERC) against ISO-NE, NextEra Energy Resources, LLC, and PSEG Companies based their complaint on the fact that the Access Northeast project would have the effect of "suppressing gas prices and wholesale power prices."[2]

[2] Complaint and Request for Fast Track Processing, FERC Docket No. EL16-93 (June 24, 2016).

McKEE-GRID 1-21

Request:

Has National Grid or any of its partners or consultants estimated the impact that the ANE project will have on ISO New England forward capacity market prices? If so, what is that impact? If not, why not?

Response:

Black & Veatch has not assessed the impact of the ANE Project on ISO New England forward capacity market prices. Black & Veatch's cost benefit analysis focused on the potential electric energy savings, since it makes up the largest portion of cost to electric ratepayers.

McKEE-GRID 1-22

Request:

It is not unreasonable to assume that retiring non-gas-fired generating units would be replaced by additional new gas-fired generation, thereby adding to demand for natural gas in New England.

A. Is there any risk that the gas price suppression coupled with likely subsidization of a subset of gas-fired generators will result in further retirements of non-gas-fired generation in New England?

B. Has Black & Veatch accounted for this effect in their Reference Case with ANE?

Response:

A. Any time that a generator receives less energy margin while their fixed costs stay the same, there will be a higher risk of further retirements. In addition, capacity prices could rise or fall, and this could have an effect on the decision of generators to retire or remain in service.

B. As stated in Schedule GJW-3, during 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 capacity retirements of older coal, and oil and gas steam 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 steam capacity retirement across the region.

Prepared by or under the supervision of: Denny K. Yeung and Gary J. Wilmes

McKEE-GRID 1-23

Request:

What efforts are the EDCs in New England making to ensure additional coal and oil-fired generation is not lost from retirements?

Response:

The Company is not aware of any efforts by the EDCs in New England to ensure that additional coal and oil-fired generation capacity is not retired.

As ISO-NE explains in its Regional Electricity Outlook:

> The rising environmental and economic costs associated with oil and coal have made it difficult for older power plants that use these fuels to compete against newer, faster generators that run on cleaner fuel sources, such as natural gas. These older plants can require up to 24 hours to reach full power production, making it difficult for ISO operators to rely on them when system conditions are tight. Oil units tend to have very limited fuel supplies on site to avoid the expense of purchasing oil that they may not use. So, even when called to run, they often can't run for very long. (The winter reliability programs implemented by the ISO over recent winters have helped address this by incentivizing on-site oil storage.) By operating infrequently, these resources cannot recover the cost of capital investments to maintain their plants and ensure performance—nor can they afford new control technologies to meet stringent state, regional, and federal environmental requirements. For many, the only option is to retire.
>
> The region's nuclear power plants, which for years have provided baseload generation, face similar challenges. Given today's generally lower energy market prices, these resources are having trouble recouping enough to support long-term operations and the costs of compliance with regulatory requirements.
>
> More than 4,200 megawatts (MW) of the region's nongas generating capacity has retired recently or plans to retire soon. This

includes several oil- and coal-fired units, as well as two nuclear plants that were part of the region's baseload generation. Between winter 2013/2014 and 2014/2015 alone, the region lost over 1,000 MW of non-gas capacity from Salem Harbor Station, Mount Tom Station, and Vermont Yankee Nuclear Power Station.

"At risk" for closing are another 6,000 MW from additional coal- and oil-fired generators, which are displaced from the electric energy market on most days by gas-fired units. But they are still critical for meeting the region's demand in winter, particularly when natural gas supplies are limited. In total, about 30% of the region's generating capacity could be gone by 2020. These retiring resources are likely to be replaced by more natural-gas-fired resources, thereby exacerbating the region's already constrained natural gas transportation system.[1]

[1] See http://www.iso-ne.com/about/regional-electricity-outlook/grid-in-transition-opportunities-and-challenges/power-plant-retirements.

McKEE-GRID 1-24

Request:

Gaining commitments from gas-fired electric generators or their agents to procure the capacity and services of the ANE project is fundamental to the success of this venture. So the needs, motivations and alternatives that gas-fired electric generators have with regard to their fuel supply are at the heart of the business case for the ANE project.

A. Please describe the nature and extent of the need that these generators have for the offerings in the ANE project.

B. What will motivate these generators to purchase the capacity and services of the ANE project at competitive prices?

C. What alternatives do the generators have besides the ANE project for meeting their fuel supply needs in the winter?

D. How does the ANE project stack up with these alternatives in terms of the economics of each alternative from the generator's standpoint? Which is the most economic choice?

Response:

Please see the response to Data Request McKEE-GRID 1-12. Also, please see the response to Data Request McKEE-GRID 1-25.

Prepared by or under the supervision of: Timothy J. Brennan

McKEE-GRID 1-25

Request:

ISO New England is introducing the Pay-for-Performance program to provide incentives and penalties to drive generators to ensure they have fuel to operate when needed. What is the most cost-effective way for gas-fired electric generators to accomplish this?

Response:

As included in the in response to Data Request OER-2-13, ISO-NE provided the following information on expected results of the "Pay-for-Performance" in a July 6, 2015 letter to the Massachusetts Department of Energy Resources (available at http://www.iso-ne.com/static-assets/documents/2015/07/iso_response_doer_info_request_july2015.pdf):

> Pay-for-performance
>
> Over a period of several years, the ISO observed deterioration in performance across much of the region's generating fleet during times when the power system was operating under stressed conditions. The ISO determined that the resource performance requirements in the Forward Capacity Market (FCM) were not sufficient to ensure a reliable system and we concluded that this posed a serious risk to power system reliability. The ISO worked through a regional stakeholder process and the Federal Energy Regulatory Commission (FERC) subsequently approved our proposal to strengthen the FCM performance obligations and incentives with what is referred to as "pay-for-performance" or "PFP."
>
> PFP created a two-settlement system to compensate resources in the capacity market. Resources that clear in a capacity auction are eligible to receive a base capacity payment. Then, if scarcity conditions exist (i.e., the power system in experiencing a shortage of operating reserves), PFP will pay resources based on their performance during those conditions; resources that over-perform will receive a payment, while those that underperform will receive a charge. PFP creates strong financial incentives for capacity suppliers to perform when called on during periods of system stress.

Prepared by or under the supervision of: Timothy J. Brennan

PFP is intended to create incentives for generators to make cost-effective investments to ensure they are able to perform when called on by the ISO. Most instances of non-performance by gas-fired generators during the winter season are due to the lack of access by those generators to firm gas transportation when the gas pipelines become constrained, since typically these generators do not hold firm gas transportation rights. PFP will create strong incentives for gas-fired generators to firm up their fuel supply, however it does not prescribe which solution a resource should pursue. Our analysis has concluded that installing dual fuel capability is the most cost-effective option for a typical gas generator. Thus, PFP will improve resource performance, but it will not necessarily result in added natural gas pipeline capacity, as individual generators are not likely to enter into the long-term contracts needed to fund additional gas infrastructure as long as cheaper alternatives such as dual-fueling exist.

While these actions should maintain a reliable supply of electricity under most conditions, relying on dual fuel capability is only a viable option if the states approve permits to burn oil. During the winter months when the pipelines are constrained, the region is typically dependent on the utilization of non-gas electrical supply to maintain reliability. This highlights a longer term reliability risk. More than 3,000 MW of non-gas generation have retired, or announced plans to retire, and there is the potential for further significant retirements of coal, oil and nuclear units in the years to come. Many of these resources are forty years of age or older and are experiencing significant financial and environmental pressures. As these resources cease operation, they will be replaced in large part by gas-fired resources (with the need for dual fuel capability). This will increase the demand for natural gas infrastructure to supply fuel for new resources.

Prepared by or under the supervision of: Timothy J. Brennan

McKEE-GRID 1-26

Request:

Please identify which of the following yearly metrics National Grid would be willing to make commitments regarding as indicators that the hoped-for benefits to ratepayers actually materialize:

A. A level of subscription by gas fired electric generation in the capacity and services offered by the ANE project,

B. An amount of reduction in winter basis relative to the average of the past five winters,

C. A price ceiling for retail electric rates year by year as measured by the standard offer prices set by National Grid for its residential and small commercial customers, benchmarked against the standard offer prices in effect for calendar year 2017,

D. Another metric of your choosing (please specify).

Response:

As explained in the Company's responses to Data Requests McKEE-GRID 1-3, McKEE-GRID 1-15, McKEE-GRID 1-16, and McKEE-GRID 1-17, the Company does not propose any guarantees or commitments regarding certain level of benefits or related outcomes with respect to the ANE Project.

As explained in the Company's response to Data Request McKEE-GRID 1-20, the Company is highly confident that the Proposed Agreement will deliver substantial net economic benefits for Rhode Island electricity customers.

McKEE-GRID 1-27

Request:

Please identify any and all signed contracts, offers, or commitments National Grid or the ANE project sponsors have from gas-fired electric generators (or their agents) to purchase firm transportation pipeline capacity from the ANE Capacity Manager in the event that the ANE project receives its needed approvals from FERC and the New England regulatory authorities?

Response:

The Access Northeast Project is not expected to commence service for several years and therefore it is premature to enter into arrangements to convey such capacity at this time. As the Company explained in its filing, the mode of conveyance of the pipeline capacity to generators will be via capacity release pursuant to the provisions of Algonquin's FERC tariff. The capacity is not available for release at this time. Moreover, it may be the case that much of the capacity, when it is available for release, will be procured by gas-fired generators closer to its actual use in real-time when generators are better able to anticipate the ISO-NE commitments and real-time dispatch needs specific to their individual gas-fired units.

McKEE-GRID 1-28

Request:

Refer to National Grid's latest Gas Long-Range Resource and Requirements Plan ("Plan") for the Forecast Period 2015/16 to 2024/25 on March 10, 2016. The filing is found in RI PUC Docket No. 4608.

A. In this Plan, National Grid states the following on page 32: "To address the changing gas supply landscape and to ensure its ability to reliably serve existing customer requirements as well as forecasted growth, the Company has developed and implemented a multi-pronged approach that includes incremental interstate pipeline capacity, as well as long-term LNG supply and liquefaction services."

    1. Did the Company consider signing a Precedent Agreement with the ANE project to secure a portion of the needed incremental pipeline capacity for its gas LDC customers?

    2. If not, why not?

    3. If so, what factors caused the Company not to proceed with entering into a Precedent Agreement with the ANE project?

B. One of the incremental pipeline resources that the Company lists in its Plan is a Precedent Agreement with Tennessee Gas Pipeline's Northeast Energy Direct Project (NED Project) for 35,000 MMBTU/day. Subsequent to the date of this filing, Kinder Morgan withdrew its federal application for the NED project, effectively cancelling it.

    1. Given this cancellation, what are the Company's plans to replace it in its resource portfolio?

    2. Subsequent to the March 10, 2016 filing date, is the Company now going to pursue a Precedent Agreement with the ANE project? If not, why not?

C. For the forecast period through 2024/25, how does the Company's annual cost of gas compare with the B&V annual forecast of gas prices? What accounts for the differences?

D. On Chart II-E-4, the Company shows a cost of incremental LNG vaporization of $69.79 per MMBTU and a cost of new pipeline capacity of $510.90/ MMBTU.

   1. How do these costs compare with the costs of LNG vaporization and new pipeline capacity for the ANE project?

   2. What accounts for the differences?

<u>Response</u>:

A. The Company's gas distribution system is served by two interstate pipelines – Algonquin Gas Transmission and Tennessee Gas Pipeline. These pipelines interconnect with the Company's facilities at different physical locations. In order to serve firm gas load, the Company requires deliveries by both pipelines and as the Company's load has increased, the Company has participated in expansion projects with both pipelines.

   On October 28, 2013 the Company entered into a precedent agreement with Algonquin for firm capacity on the Algonquin Incremental Market (AIM) Project which is expected to commence service on November 1, 2016. On December 19, 2014 the Company entered into a precedent agreement with Tennessee for firm transportation capacity on Tennessee's Northeast Energy Direct Project ("NED"). In light of Tennessee's suspension of the NED Project, that precedent agreement has been terminated.

   At the time that Algonquin announced its Access Northeast (ANE) Project, the Company did not have any requirement for additional deliveries by Algonquin to serve gas load and therefore, the Company did not at that time consider signing a precedent agreement with Algonquin for its gas customers.

B. In light of cancellation of Tennessee's NED Project, the Company is actively pursuing a suitable alternative. The Company has met with Algonquin and will consider whether the ANE Project can satisfy any portion of the requirements that would have been served by NED.

Prepared by or under the supervision of: John E. Allocca, Stephen A. McCauley and Denny K. Yeung

C. Black & Veatch's projected gas prices are based on our long-term market fundamental view and can differ from the NYMEX futures used in the Company's gas Long-Range Resource and Requirements Plan. Black & Veatch's analysis focused on regional market hub prices in New England, and not on upstream price hubs based on the Company's gas supply portfolio.

D. On Chart II-E-4, the Company used the unit costs of liquefied natural gas (LNG) vaporization and the AIM Project for the Rhode Island cost/benefit analysis of its design day standard. The ANE Project costs include the Acushnet LNG facility which is approximately [redacted]. The difference can be based on numerous factors including different costs of construction or differences in project design.

Prepared by or under the supervision of: John E. Allocca, Stephen A. McCauley and Denny K. Yeung

McKEE-GRID 1-29

Request:

Kinder Morgan, in its press release announcing its decision to suspend further work or expenditures on the NED Project, cited inadequate capacity commitments from prospective customers as its reason. They identified several contributing factors, including: (1) an uncertain regulatory environment; (2) innovations in production have resulted in a low-price environment, that, while good for consumers, has made it difficult for producers to make new long term commitments; and (3) current market conditions and counter-party financial instability have called into question the ability to secure incremental supply for the project. Given these market conditions, Kinder Morgan concluded that continuing to develop the project is not an acceptable use of shareholder funds. Since the ANE project faces the same, if not more, challenging market conditions (more challenging because the project is choosing to restrict its own market to electric generators), why should we accept that a gas pipeline project in New England now is a good investment for ratepayers to make when it is a bad investment for Kinder Morgan stockholders to make?

Response:

The Company did not execute the Access Northeast precedent agreement as a ratepayer investment opportunity. The purpose of executing the agreement was to acquire firm pipeline capacity that would be made available to electric generators in New England for the purpose of addressing electric market reliability concerns and reducing electric costs for customers in Rhode Island. The Company's analysis demonstrates that the Access Northeast Project will provide significant net benefits to Rhode Island customers.

McKEE-GRID 1-30

Request:

Refer to ISO New England's 2016 Regional Energy Outlook:

A. How much energy efficiency does ISO New England forecast to be deployed in the New England market by 2024?

B. How much was deployed through 2014?

C. Doesn't this show that ISO New England thinks that enough new energy efficiency will be deployed by 2024 to meet most of the need represented by the ANE pipeline capacity?

Response:

A. According the ISO New England 2016 Regional Energy Outlook (the Report), 3,600 MW of energy efficiency is expected to be deployed by 2024.

B. According to ISO New England 2016 Regional Energy Outlook, 1,500 MW of energy efficiency has been deployed through 2014.

C. The Report shows that ISO New England forecasts another 2,100 MW of energy efficiency to be deployed by 2024. Black & Veatch utilized the 2015 CELT report, which already accounts for approximately 3,579 MW by 2024. The proposed ANE Project will be able to serve the existing 9,500 MW of gas-fired generation directly connected to Algonquin and Maritimes & Northeast that currently does not hold firm pipeline capacity.

Prepared by or under the supervision of: Denny K. Yeung and Jeremy Newburger

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McKEE-GRID 1-31

Request:

Will New England electric ratepayers be required to pay for the full costs of the pipeline for the full 20 years regardless of the extent to which the pipeline is used by electric generators?

Response:

The Joint Testimony of Timothy J. Brennan and John E. Allocca (at 24) explains that "National Grid and the other EDC customers have negotiated a levelized cost for the 20-year duration of the contract" and that "[t]he rate paid by the EDCs will be based on the actual cost of construction subject to a cap." It is this levelized cost that the EDCs (including the Company in this proceeding) propose to recover from their electricity customers.

As explained in the Company's response to Data Request McKEE-GRID 1-20 (and for the reasons detailed therein), the Company is highly confident that the Proposed Agreement will deliver substantial net economic benefits for Rhode Island electricity customers over the full life of the contract.

The economic benefit-cost analysis conducted by Black & Veatch Management Consulting LLC (Black & Veatch) (see Schedule GJW-3) examined the full 20-year term of the Proposed Agreement. As shown on page 1 of Attachment DIV 1-23-2, Black & Veatch projects electricity market benefits from the Proposed Agreement (i.e., indicating that the pipeline is needed and used by electric generators) in every year that the ANE project is in service in all three of the scenarios modeled with the ANE project.

Prepared by or under the supervision of: Timothy J. Brennan

McKEE-GRID 1-32

Request:

In the Massachusetts proceeding, D.P.U. 16-05, on page 14 of John Hanger's Direct Testimony on behalf of Direct Energy, he states the following: "The ANE project over its 20-year life is a stranded asset waiting to happen." What assurances can you give the small business ratepayers in Rhode Island that Mr. Hanger is wrong about that?

Response:

The risk for small business customers in Rhode Island is the economic harm that continued excessive electricity costs caused by natural gas transportation constraints in New England will have on them. The Testimony of Michael C. Calviou (at 22) explains that:

> [H]igh 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 [emphasis added].

Governor Raimondo has made essentially the same point about the harmful impact that high energy prices have on Rhode Island businesses. 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.[1]

As explained in the Company's response to data request McKEE-GRID 1-20 (and for the reasons detailed therein), the Company is highly confident that the Proposed Agreement will deliver substantial net economic benefits for Rhode Island electricity customers, including small business customers, over the full life of the contract.

Mr. Hanger is wrong that the ANE Project is a "stranded asset waiting to happen." This assertion is clearly refuted by the benefit-to-cost ratio of [redacted] calculated by Black & Veatch Management Consulting, LLC (Black & Veatch) for their core scenario analyzing the Proposed Agreement—i.e., the "Reference Case - With ANE Only" scenario (see Table 8 in Schedule GJW-3). That benefit-to-cost ratio means, in essence, that Black & Veatch's modeling analysis found that the Proposed Agreement, over its 20-year term, will pay for itself more than [redacted] times over in form of lower electric commodity costs from the perspective of Rhode Island electricity customers.

The economic benefit-cost analysis conducted by Black & Veatch (see Schedule GJW-3) examined the full 20-year term of the Proposed Agreement. As shown on page 1 of Attachment DIV 1-23-2, Black & Veatch projects electricity market benefits from the Proposed Agreement (i.e., indicating that the pipeline is needed and used by electric generators) in every year that the ANE project is in service in all three of the scenarios modeled with the ANE project. Moreover, Attachment DIV 1-23-2 shows that the average (undiscounted) total electricity market benefits in each of those three scenarios is actually higher for the last ten years of the contract term than for the first ten years that the ANE Project is fully in-service. That is the exact opposite of what one would expect to see for a "stranded asset waiting to happen."

[1] 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.

McKEE-GRID 1-33

Request:

Are there terms in the Precedent Agreement that mitigate the exposure of ratepayers in the event that the ANE project becomes uneconomic or underutilized?

Response:

Yes, the negotiated rate agreement protects the customers from these risks. In accordance with the agreement, the customers bear no risk in the event that the project becomes uneconomic or underutilized. The only adjustment provided for under the negotiated rate agreement is a mechanism to adjust for differences between actual and estimated project capital costs; this adjustment is subject to a cap. The rate is not subject to adjustment for any other reason. Specifically, the rate paid by customers is not subject to an increase if the pipeline becomes uneconomic or underutilized.