nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

April 9, 2015

VIA HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 4556 - 2016 Standard Offer Service Procurement Plan
2016 Renewable Energy Standard Procurement Plan
<u>Responses to Division Data Requests – Set 1</u>

Dear Ms. Massaro:

Enclosed are ten (10) copies of National Grid's[1] responses to the first set of data requests issued by the Rhode Island Division of Public Utilities and Carriers in the above-referenced matter.

Thank you for your attention to this transmittal. If you have any questions, please contact me at (401) 784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Docket 4556 Service List
Leo Wold, Esq.
Steve Scialabba, Division

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

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Certificate of Service

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

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

Joanne M. Scanlon

April 9, 2015
Date

Docket No. 4556 - National Grid – 2016 Standard Offer Service (SOS) and Renewable Energy Standard (RES) Procurement Plans
Service List updated 4/7/15

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Division 1-1

Request:

Regarding Schedule 1, the procurements for the commercial and residential groups do not add up to 100%. Please provide a schedule that displays procurements for 100% of standard offer load.

Response:

Schedule 1 reflects only the solicitations pursuant to the approved 2015 Standard Offer Service (SOS) Procurement Plan. It illustrates the laddered and layered procurement plan described in the Direct Testimony of Margaret M. Janzen for the 2015 solicitations. Each quarterly solicitation procures SOS for a specific term and load obligation, and some contracts will have delivery periods beyond 2015. The procurements resulting from the 2015 SOS Procurement Plan, in conjunction with procurements from the 2013 Standard Offer Service Procurement Plan (Docket No. 4315) and 2014 Standard Offer Service Procurement Plan (Docket No. 4393), fully satisfy the Company's SOS obligation for the period July 2015 through June 2016. The 2015 SOS Procurement Plan also partially satisfies the Company's SOS obligation for July 2016 through December 2017. The Company's SOS obligations for this period will be fully met in conjunction with procurements made as a result of the 2016 Standard Offer Service Procurement Plan and the 2017 Standard Offer Service Procurement Plan.

Schedule 1 is reproduced below to include the contracts from previous procurement plans.

Residential Solicitations

NOTE:
2013 SOS Plan.
2014 SOS Plan.
Approved FRS solicitations that have been purchased are shown in yellow - 2015 SOS Plan.
Approved FRS solicitations are shown in white - 2015 SOS Plan.

Final Bid Date	Jul-2015	Aug-2015	Sep-2015	Oct-2015	Nov-2015	Dec-2015	Jan-2016	Feb-2016	Mar-2016	Apr-2016	May-2016	Jun-2016	Jul-2016	Aug-2016	Sep-2016
2013 Q4	15%	15%	15%	15%	15%	15%									
2014 Q1	20%	20%	20%	20%	20%	20%									
2014 Q2															
2014 Q3	20%	20%	20%	20%	20%	20%									
2014 Q4	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
2015 Q1	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
2015 Q2							20%	20%	20%	20%	20%	20%			
2015 Q3							20%	20%	20%	20%	20%	20%	20%	20%	20%
2015 Q4							15%	15%	15%	15%	15%	15%	15%	15%	15%
On-Going Spot Market Purchases	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%

Final Bid Date	Oct-2016	Nov-2016	Dec-2016	Jan-2017	Feb-2017	Mar-2017	Apr-2017	May-2017	Jun-2017	Jul-2017	Aug-2017	Sep-2017	Oct-2017	Nov-2017	Dec-2017
2013 Q4															
2014 Q1															
2014 Q2															
2014 Q3															
2014 Q4	15%	15%	15%												
2015 Q1	20%	20%	20%												
2015 Q2															
2015 Q3	20%	20%	20%												
2015 Q4	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
On-Going Spot Market Purchases	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-1, page 2

Commercial Solicitations

Final Bid Date	Jul-2015	Aug-2015	Sep-2015	Oct-2015	Nov-2015	Dec-2015	Jan-2016	Feb-2016	Mar-2016	Apr-2016	May-2016	Jun-2016	Jul-2016	Aug-2016	Sep-2016	Oct-2016	Nov-2016	Dec-2016
2014 Q4	30%	30%	30%	30%	30%	30%												
2015 Q1	30%	30%	30%	30%	30%	30%												
2015 Q2	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%						
2015 Q3							30%	30%	30%	30%	30%	30%						
2015 Q4							30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
On-Going Spot Market Purchases	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%

NOTE:
2014 SOS Plan.
Approved FRS solicitations that have been purchased are shown in yellow - 2015 SOS Plan.
Approved FRS solicitations are shown in white - 2015 SOS Plan.

Schedule 1 does not include the contracts from the 2016 SOS Procurement Plan and the 2017 SOS Procurement Plan. As described in the testimony of Ms. Janzen, the Company proposes to modify the 2015 SOS Procurement Plan and to transform the Commercial Group's procurement schedule to the Residential Group's schedule. Schedule 2B and Schedule 2C contained in the Company's filing include the proposed modifications to the 2015 SOS Procurement Plan and the proposed 2016 SOS Procurement Plan.

Division 1-2

Request:

Schedule 4, the Master Power Agreement, does not appear to be redlined. Please provide a redlined copy showing changes from the version last approved by the Commission.

Response:

Schedule 4 (the Master Power Agreement (MPA)) is identical to the version approved by the PUC in the 2015 Standard Offer Service Procurement Plan.

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-3

Request:

On page 14 of 63 of the Janzen testimony, it states that there are no significant changes to the MPA. Please describe all changes made and explain how they were determined not to be significant.

Response:

Schedule 4 (the Master Power Agreement (MPA)) is identical to the version approved by the PUC in the 2015 Standard Offer Service Procurement Plan. Accordingly, Ms. Janzen's testimony on page 14 of 63 noted above should be interpreted to mean that "there are no changes to the MPA."

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-4

Request:

On page 14 of 63 of the Janzen testimony, it states that edits to the SOS RFP notice would be applied retroactively in the 2015 SOS plan. Please explain why retroactive application is necessary or desirable, why the Company is doing so, and how it will be implemented.

Response:

Edits to Schedule 6 (SOS RFP Notice (Template)) are necessary to implement the Company's proposal to solicit one "flat" bid price for the entire contract term for each Residential and Commercial Group bid block, instead of varying "shaped" bid prices for each month. As described in the Direct Testimony of Margaret M. Janzen, the Company proposes flat bid prices to help make the migration process easier for customers who select a Non-regulated Power Producer (NPP). These proposals will result in the gradual decrease and eventual elimination of the billing adjustment for customers in the Residential and Commercial Groups that switch from Standard Offer Service (SOS) to a NPP.

To effect this change for customers as soon as possible, the Company proposes to amend the 2015 SOS Procurement Plan and implement this proposal immediately after approval. If approved, the Company will procure a flat bid price for the entire contract term for all remaining 2015 SOS Procurement Plan solicitations. If the Company does not implement this proposal for the remaining 2015 solicitations, all contracts under the 2015 SOS Procurement Plan would retain the monthly bid price format. In order to completely eliminate the variability between monthly contract prices and a flat, or uniform, price across all months and, thereby eliminating the need for the billing adjustment, all existing shaped bid price transactions must expire and be replaced by flat bid price transactions. The Residential Group's 2015 fourth quarter procurement is for the period ending December 2017. Because this transaction is currently in the monthly bid price format, the billing adjustment would not have been completely eliminated until December 2017. Thus, under the Company's proposal for prospective application of flat bid prices to the balance of solicitations during 2015, the billing adjustment will be completely eliminated a year earlier, by December 2016.

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-5

Request:

On page 15 of 63 of the Janzen testimony, it states that there are no significant changes to Schedule 6. Please describe all changes made and explain how they were determined not to be significant.

Response:

Schedule 6 (the SOS RFP Summary (Template)) is identical to the version approved by the PUC in the 2015 Standard Offer Service Procurement Plan. Accordingly, Ms. Janzen's testimony on page 15 of 63 noted above should be interpreted as "there are no changes to Schedule 6".

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-6

Request:

On page 16 of 63 of the Janzen testimony, it states that the elimination of shaped prices would be applied retroactively in the 2015 SOS plan. Please explain why retroactive application is necessary or desirable, why the Company is doing so, and how it will be implemented.

Response:

Please see the Company's response to Division 1-4.

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-7

Request:

On page 19 of 63 of the Janzen testimony, it states that some FRS suppliers have indicated that an incremental premium would not be added to create flat prices. Please list the suppliers that offered such an opinion and describe how the Company obtained that opinion. Provide any available documentation. Also, has the Company performed any analysis that would indicate whether such a risk premium would be added? If so, please provide the results of that analysis and the underlying assumptions and workpapers.

Response:

The Company obtained the information regarding the likelihood of risk premiums through informal discussions with some of its FRS suppliers active in recent solicitations.

One FRS supplier indicated it would not include an incremental risk premium for flat bid prices.

A second FRS supplier indicated that it did not believe it would add an incremental risk premium.

Five other FRS suppliers indicated a preference to continue with the varying shaped bid prices. These suppliers indicated that there are negative implications to flat bid prices but did not indicate the size of a risk premium, if any. The suppliers indicated that they hedge their load obligations monthly and would therefore prefer that the SOS prices remain monthly. The Company's transactions start with high cost months: January and February in the winter and July and August in the summer. The suppliers indicated that the transactions with flat bid prices would result in financial losses in the first few months of a transaction, and that there is a cost to finance these losses.

For the 2016 SOS Procurement Plan, the Company did not perform any analysis to determine if an additional risk premium would be included in flat bid prices.

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-8

Request:

Have any changes been made to Schedule 7 from the last version approved by the Commission? If so, please provide a redlined copy showing these changes.

Response:

There are no changes to the procurement methods approved in the 2015 Renewable Energy Standard (RES) Procurement Plan. The percentage requirement from New Renewable Energy Resources increased in 2016 to 8% from 6.5% in 2015. Please see Attachment DIV 1-8, which shows the redlined edits made to the approved 2015 RES Plan.

Please note that the graphs included in the approved 2015 RES Procurement Plan were also updated for the proposed 2016 RES Procurement Plan, but these could not be redlined.

Prepared by or under the supervision of: Margaret M. Janzen

~~2015~~2016 Renewable Energy Standard Procurement Plan

I. Objectives

A. This plan satisfies Section 8.2 of the Commission's Rules and Regulations Governing the Implementation of a Renewable Energy Standard ("RES Regulations"). Under Section 8.2, the Company is required to annually submit a Renewable Energy Standard Procurement Plan that sets out its procedures for obtaining resources that satisfy its obligations under the Rhode Island Renewable Energy Standard ("RES") (R.I. Gen. Laws § 39-26-1 et seq.).

B. The plan is for the procurement of the RES renewable energy certificates ("RECs") to meet the obligations associated with provision of Standard Offer Service ("SOS") for ~~2015.~~2016. A competitive procurement process will be utilized for a portion of the ~~2015~~2016 requirements New RECs and for all ~~2015~~2016 requirements for Existing RECs, either bundled with Full Requirements Service ("FRS") transactions or purchased separately.

II. Requirements

The following table displays the anticipated number of RECs that will be necessary to satisfy RES Regulations in ~~2015.~~2016.

Year	Percentage from New Renewable Energy Resources	Percentage from *either* New *or* Existing Renewable Energy Resources	Total RES Target Percentage	Estimated Standard Offer Load (MWhs)	Standard Offer Existing RES Obligation (RECs)	Standard Offer New RES Obligation (RECs)
~~2015~~ 2016	~~6.5~~8.0	2.0	~~8.5~~10.0	~~5,227,593~~5,208,086	~~104,552~~104,162	~~339,794~~416,647

III. REC Procurement

A. In order to comply with the Distributed Generation Standard Contracts Act and the Long-Term Contracting Standard for Renewable Energy ("Long Term Renewable Contracts"), the Company enters into transactions with renewable energy resources that include New RECs. As approved in Docket No. ~~4393,~~4393 and Docket No. 4490, the Company proposes to continue to utilize these RECs to partially satisfy its New RES requirements for the SOS load. The Company believes SOS customers will benefit from this approach because it minimizes transaction expenses.

As described in Docket No. 4338, the Company proposes to determine the market costs of these RECs for reconciliation by utilizing the most representative data sources, such as recent solicitation results, broker sheets, and market indices. This market cost will be charged to SOS customers for their RES obligation and the same amount will be credited to delivery customers.

B. Procurement of RECs (both New and Existing) will be linked to the purchase of FRS contracts through SOS competitive solicitations. Separate pricing would be requested from bidders to accept the RES obligations for the period served by the SOS contract. The bidders may decline to provide RES pricing. The lack of RES pricing will not impact the award of FRS transactions because the lowest FRS price will be the winner regardless of RES pricing. The Company will then evaluate the RES pricing provided by the winning bidders and compare it to the Company's best estimate of REC market prices. If the pricing provided by the winning SOS supplier is at or less than the Company's market price estimate, the SOS supplier will also be contracted to provide the RECs necessary to satisfy the RES obligation. For FRS RFPs that span multiple years, the Company will continue to only evaluate the bidders' RES pricing for the first year.

The Company continues to reserve the right to not award RES pricing in all SOS competitive solicitations. Due to the amount of New RECs acquired from the Long Term Renewable Contracts, the Company may not ~~to~~ award RES pricing in a SOS solicitation.

C. The Company will issue standalone REC RFPs to procure the remaining REC amounts for each REC class necessary to satisfy the RES Regulations. The Company intends to issue two or more REC RFPs in ~~2015.~~2016.

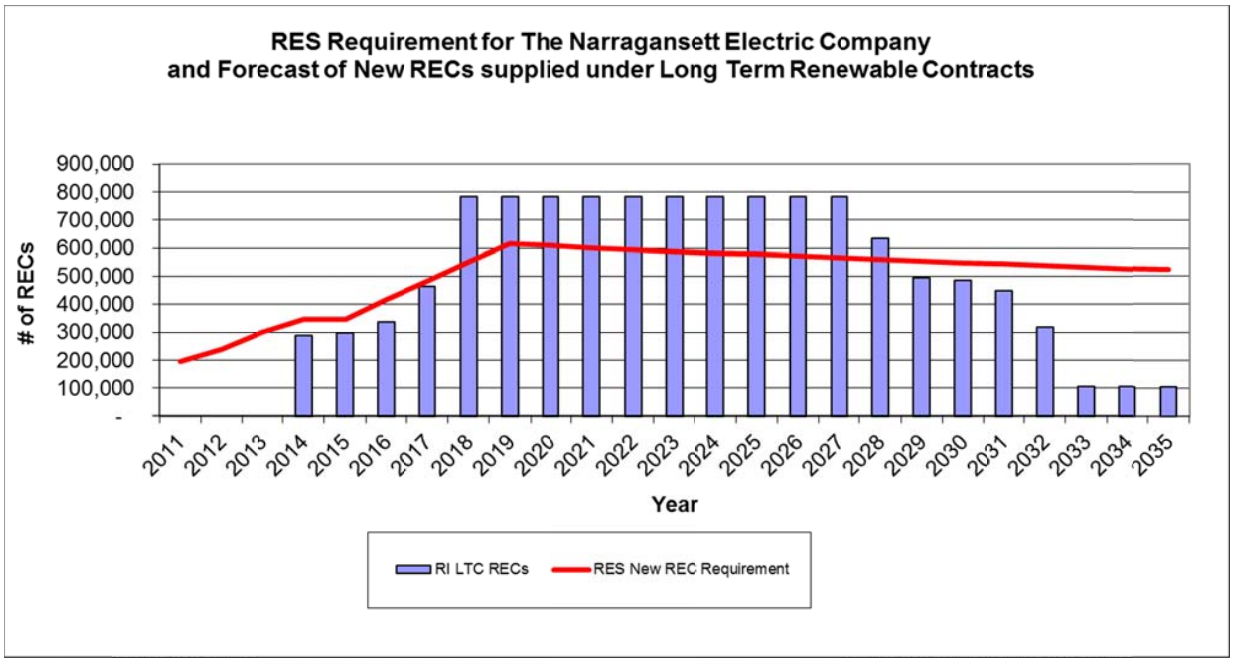
The principal criteria to be used in evaluating REC RFP proposals will be lowest evaluated bid price. In the event of identical low bids, the Company will allocate the offered RECs to all bidders with identical prices based on the quantities bid and the quantities solicited. For example, the Company solicits 5,000 RECs and receives two identical low bid prices. Bidder A offers 5,000 RECs and Bidder B offers 2,500 RECs. Bidder A will receive 3,333 RECs (5,000 / 7,500 * 5,000) and Bidder B will receive 1,667 RECs (2,500 / 7,500 * 5,000).

D. The Company may also evaluate unsolicited offers from brokers or other parties.

E. If the Company still has an obligation shortfall in a calendar year, the Company will make an Alternative Compliance Payment to the RI Economic Development Corporation for the unmet obligation.

IV. New RES Requirement and Forecast of RECs from Long Term Renewable Contracts

The chart below shows a projection of the New RES requirement over the next 20 years compared to the estimated output of RECs obtained through the Long Term Renewable Contracts.



Division 1-9

Request:

Please provide the data used to create that graph on page 3 of Schedule 7 in a live spreadsheet, including but not limited information on individual projects and any assumptions made by the Company.

Response:

As described on p. 26 of the Direct Testimony of Margaret M. Janzen, the Company made various assumptions regarding its Long-Term Renewable Contracts including commercial operation dates, project size, output, and contract capacity. The Company used reasonable estimates for the commercial operation dates of the executed Long-Term Renewable Contracts (including the Distributed Generation Standard Contracts) and for future Long-Term Renewable Contracts obligations to estimate the quantity of Renewable Energy Certificates (RECs) supplied. The Company assumes that it will satisfy its obligation and execute the remaining Long-Term Renewable Contracts, which will become commercially operable and produce RECs, by 2018. The Company also assumes that the Long-Term Renewable Contracts maintain operation through contract terms and meet estimated annual production volumes.

Please see the Excel file attachment "4556 DIV 1-9 - RI RES Requirements with LTC Obligations" for the assumptions regarding the quantity of RECs supplied from the Long-Term Renewable Contracts.

The Company used a forecast of the SOS load to calculate the New REC requirement. The forecasted annual SOS loads were multiplied by the Rhode Island Renewable Energy Standard (RES) New Renewable Resource Requirement (Section 4.2 of the Rules and Regulations Governing The Implementation Of A Renewable Energy Standard promulgated pursuant to the Renewable Energy Standard, R.I.G.L. § 39-26-1 et seq. to facilitate the development of renewable energy resources for the benefit of customers in Rhode Island) to determine the New REC requirement. The Company assumes that the New REC requirement established in 2019 shall be maintained for future years in accordance with R.I.G.L. § 39-26-4(a)(5). Please see the Excel file 4556 DIV 1-9 - RI RES Requirements with LTC Obligations" provided as Attachment DIV 1-9 for a detailed calculation of the Company's New REC requirement.

The data used to create the graph in Attachment DIV 1-9 has several minor updates from the data used to create the graph in Schedule 7. However, the conclusions made in the testimony have not changed: New RECs from the Long Term Renewable Contracts will meet most of the

Company's New RES requirement through 2017, and thereafter will likely exceed the Company's obligation.

Prepared by or under the supervision of: Margaret M. Janzen

Attachment DIV 1-9

Per the Division's request, the graph on page 3 of Schedule 7 is being provided in Excel format as Attachment DIV 1-9. The Company has provided a copy of Attachment DIV 1-9 on a CD-ROM. The CD-ROM is being provided to the PUC and to the Division.

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-10

Request:

Are the filed versions of Schedules 8, 9, and 10 identical to the last versions approved by the Commission? If not, please provide redlined versions showing any changes made.

Response:

Schedule 8 (the Certificate Purchase Agreement (CPA)), Schedule 9 (the RES RFP Notice (Template)), and Schedule 10 (the RES RFP Summary (Template)) are identical to the versions approved by the PUC in the 2015 Renewable Energy Standard Procurement Plan.

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-11

Request:

On page 39 of 63 of the Janzen testimony, it states that Pascoag customers are exposed to capacity market prices for the three-year duration of the TransCanada contract. What is the start date, end date, and term of the TransCanada contract? And, how far into the future are capacity market prices set via FCM auctions?

Response:

The Confirmation Letter included in the Prefiled Testimony of Michael R. Kirkwood[1] states that the agreement between TransCanada Power Marketing Ltd. and Pascoag Utility District commences on January 1, 2015 and terminates on December 31, 2017.

The ninth Forward Capacity Market auction was held on February 2, 2015, and the results were filed at the Federal Energy Regulatory Commission on February 27, 2015. The ninth auction is for the capacity commitment period from June 1, 2018 through May 31, 2019.

[1] Docket No. 4529: Year-End Filing for Standard Offer Service, Transmission, and Transition Reconciliation.

Division 1-12

Request:

Regarding page 41 of 63 of the Janzen testimony, provide any data available to the Company that shows whether Pascoag's entitlements are predominantly on peak.

Response:

The Company does not have access to Pascoag Utility District's (Pascoag) contracts' load data.

Pascoag's Schedule A of Docket No. 4529, Year-End Filing for Standard Offer Service, Transmission, and Transition Reconciliation, provides 2014 Purchased Energy (KWH) by contract but does not separate it into on and off peak. Schedule F provides forecasted energy for 2015 by contract but does not clearly separate it into on and off peak.

The Confirmation Letter detailing the agreement between TransCanada Power Marketing Ltd. and Pascoag is included in the Prefiled Testimony of Michael R. Kirkwood in the same docket. This Confirmation Letter includes Schedule 1 (Pascoag Fixed Volumes). Earlier in his testimony, Mr. Kirkwood describes that this agreement for load following energy is determined by "taking Pascoag's actual day-to-day load requirement and subtracting the estimate of our other entitlements (Seabrook, NYPA, RISE, Miller Hydro, and Spruce Mountain Wind)." One could logically assume that the Pascoag Fixed Volumes in Schedule 1 is the forecast of Pascoag's entitlements. The data in Schedule 1 is shown below. However, several of the entitlements are renewable resources and intermittent by nature. Their output may deviate from this forecast. In addition, some of the NYPA volumes are interruptible and have deviated from forecasts in the past.

Division 1-12, page 2 of 3

Pascoag's "FIXED" Supply Volumes for 2015			
	PEAK	7x8	2x16
Jan	3.641	3.925	3.292
Feb	3.673	3.317	3.286
Mar	4.971	3.356	4.292
Apr	5.084	3.494	4.492
May	4.844	3.222	4.219
Jun	5.044	3.299	4.270
Jul	4.937	3.363	4.326
Aug	4.842	3.432	4.405
Sep	4.816	3.429	4.405
Oct	3.437	2.077	3.034
Nov	4.673	3.293	4.279
Dec	3.386	3.129	3.111

Pascoag's "FIXED" Supply Volumes for 2016			
	PEAK	7x8	2x16
Jan	3.641	3.925	3.292
Feb	3.673	3.317	3.286
Mar	4.971	3.356	4.292
Apr	5.084	3.494	4.492
May	4.844	3.222	4.219
Jun	4.825	3.076	4.039
Jul	4.790	3.211	4.169
Aug	4.728	3.308	4.260
Sep	4.668	3.280	4.263
Oct	4.468	3.104	4.057
Nov	4.510	3.129	4.113
Dec	3.201	2.940	2.922

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-12, page 3 of 3

Pascoag's "FIXED" Supply Volumes for 2017			
	PEAK	7x8	2x16
Jan	3.446	3.102	3.094
Feb	3.507	3.153	3.123
Mar	4.734	3.119	4.051
Apr	3.638	2.053	3.054
May	4.591	2.973	3.979
Jun	4.825	3.076	4.039
Jul	4.790	3.211	4.169
Aug	4.728	3.308	4.260
Sep	4.668	3.280	4.263
Oct	4.468	3.104	4.057
Nov	4.510	3.129	4.113
Dec	3.201	2.940	2.922

Prepared by or under the supervision of: Margaret M. Janzen

Division 1-13

Request:

Regarding page 52-53 of 63 of the Janzen testimony, what is the expected capital cost, the expected in-service date, and the annual revenue requirements for the Access Northeast pipeline project. Provide the basis for the estimated savings of $1 billion per year during normal weather conditions, including but not limited to all assumptions, and workpapers. Provide any savings estimates performed by or in the possession of the Company. Also provide any available estimates of how the costs and benefits of the project will be allocated to Rhode Island ratepayers, including SOS customers and customers served by NPPs.

Response:

The Access Northeast project remains in the early stages of consideration at National Grid. Therefore, the Company is not able to quantify the expected capital cost or annual revenue requirement for the project at this time. The basis for the estimated savings of $1 billion per year is a study by ICF International entitled "Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England." Please see Attachment DIV 1-13 for a copy of this study. This study was prepared for Eversource Energy and Spectra Energy. National Grid had no involvement in the study. Although National Grid did engage a third-party vendor to analyze the benefits of adding new pipeline projects, such as the Access Northeast project, the completed analysis was performed over one year ago and utilized generic data based on a set of general assumptions and pipeline guidelines. Accordingly, the Company does not possess, nor has it performed, any savings estimates specific to the Access Northeast project, nor has the Company developed any estimates of the costs and benefits of the project to Rhode Island customers at this time.

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

Prepared for

Eversource Energy and Spectra Energy

Prepared by

ICF International
9300 Lee Highway
Fairfax, VA 22031

1331 Lamar
Suite 660
Houston, TX 77010

February 18, 2015

Disclaimer

This report reflects ICF's opinion and best judgment based upon the information available to it at the time of its preparation.

ICF's opinions are based upon historical relationships and expectations that ICF believes are reasonable. Some of the underlying assumptions, including those detailed explicitly or implicitly in this report, may not materialize because of unanticipated events and circumstances.

ICF's opinions could, and would, vary materially, should any of the above assumptions prove to be inaccurate.

Table of Contents

Introduction

ICF International (ICF) was engaged by Eversource Energy (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 increased its reliance on natural gas-fired electricity generation in recent years. At present, approximately 50 percent of New England's power comes from gas-fired generation; the projected retirements of regional nuclear and coal-fired generating facilities, which will be replaced in large part by new gas-fired generation, will further this trend.

The growth in new gas-fired generation raises important questions about the reliability of gas supplies to meet that demand. 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 peak gas demand conditions.[1] 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.[2] This equates to roughly 5,700 MW of capacity, or up to approximately 30% of the region's gas generation capacity.

Central to the issue is New England's reliance on interruptible gas supplies for much of its power generation fuel supply. Unlike local gas distribution companies (LDCs), who contract for firm pipeline and storage services that assure gas supplies on the coldest of days, most gas-fired generators in New England contract for non-firm pipeline capacity and gas supplies to run their plants. This practice has worked in the past because interruptible pipeline capacity has been widely available during most times of the year. Going forward, natural gas-fired plants will shoulder much of the load presently served by retiring nuclear and coal plants. This means that winter season gas demand for power is growing. Without new gas infrastructure, relatively little pipeline capacity will be available for interruptible services in the winter months, as LDCs continue to utilize their firm capacity to meet heating demands.

The ICF study for ISO-NE indicates that without new firm sources of gas supplies, there is a rising probability of gas supply deficits occurring on a significant number of days throughout the winter[3]. A gas supply deficit[4] is a serious threat to the reliable operation of the New England electric system that, under certain conditions, could result in costly electric system disruptions.

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[1] Gas utilities typically define peak demand conditions in terms of "design-day" criteria, design day refers to the coldest weather conditions over a given time interval, such as 20 or 30 years.

[2] 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.

3 Ibid, page 5.

[4] As described in more details later in this report, gas supply deficit is the amount that remaining gas firm supplies to meet power sector demand is less than the projected dispatch needs for gas-fired generation.

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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."[5] 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[6].

In response to this 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[7]. For its analysis, ICF has assumed that the project will add 500 MMcf/d pipeline capacity and 6 Bcf of peak supply through storage facilities with a maximum deliverability of 400 MMcf/d, starting in November 2018.

The need for natural gas infrastructure projects that introduce incremental firm natural gas supplies to New England or electric infrastructure projects that reduce the demand for natural gas during peak winter days is well documented. To that end, the New England Governors released a statement in December 2013 committing to support "investments in additional energy efficiency, renewable generation, natural gas pipelines, and electric transmission."[8] In the statement, Governor LePage of Maine expressed that New England's "high energy prices drain family budgets and are a significant barrier to attracting business investment, especially in energy-intensive industries… This energy infrastructure initiative can bring these world-class resources to start powering New England industry and start saving money for families across our states."

It is important to recognize that the economic benefits of new firm gas supplies will accrue to New England stakeholders even when conditions do not result in gas supply deficits or system disruptions. New England's natural gas and electricity grids operate as efficient and transparent markets where energy prices can rise quickly in response to tightening supply conditions. For example, ICF estimates that New England's 2013/2014 electric costs were approximately $3.2 billion higher than the previous winter (December to March), caused largely by Polar Vortex cold weather episodes and the gas market price volatility that cascaded across the East.[9] Grid operators successfully averted gas supply deficits and major system disruptions, but the economic burden on consumers was nonetheless substantial. ICF estimates that if the Access Northeast project had been in operation last year, New England could have saved $2.5

[5] 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.

6 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 demand side response program, and incentives to encourage dual fuel and oil generation capabilities. The 2014/2015 winter reliability program includes a LNG component.

[7]http://www.spectraenergy.com/content/documents/Projects/NewEngland/Access-Northeast-Project-Brochure.pdf

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

[9] As illustrated later in this report, electric prices in New England are strongly correlated to natural gas prices. High and volatile gas prices are quickly communicated to power markets.

billion last winter. The addition of firm gas supplies and transportation infrastructure can mitigate the risk of future energy price shocks, even during normal winters. As presented later in this report, ICF estimates that a project similar to Access Northeast, on average, could lower consumer energy costs by $780 million to $1.2 billion per year during the initial ten-years after it enters service in 2018.

Whether during an extreme year such as 2013/2014 or a normal weather year, ICF's analysis of regional energy price behavior indicate that the potential cost savings from having additional firm gas supplies in New England are well in excess of the annual cost of constructing and operating the infrastructure project.

Summary Findings and Conclusions

New England needs incremental firm natural gas supplies for the electric sector during winter months

In recent years, New England has steadily increased its reliance on natural gas fired generation as coal and nuclear power plants have been retired. 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. 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, and Mount Tom) and the addition of new gas-fired capacity (Footprint Power).

New England's reliance on non-firm winter gas supplies poses increasing risks on electricity consumer costs

New England LDCs hold the vast majority of firm capacity rights on pipelines. In contrast, power generators typically rely on interruptible pipeline capacity and the spot natural gas market to procure supply. During peak winter demand periods, pipelines must prioritize gas deliveries first to firm customers, with any remaining capacity allocated to the highest bidders in the market. As evidenced by last winter's record high prices, the resulting competition for scarce interruptible pipeline capacity (particularly during peak demand periods) places upward pressure on spot prices for natural gas. This caused regional wholesale electricity prices to soar, because those prices are set by bids from marginal generators, typically gas-fired units. Last winter, due to the existence of the ISO-NE Winter Reliability program, there were several days where the marginal price was set by oil-fired generation. Had this program not been in place, electric prices would have been even higher.

Diminishing New England gas supply sources increase consumer exposure to non-firm gas supplies

To supplement gas supplies transported by pipelines from US and Western Canadian fields, New England has historically relied on imports produced from smaller 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.

Atlantic Canada gas supplies have principally come from the Sable Offshore Energy Project (SOEP) off the coast of Nova Scotia. SOEP has experienced deep declines in production during the past few years and is expected to cease production completely within 10 years. A new offshore field called Deep Panuke commenced production in Q3 2013, but has had production issues resulting in numerous "shut-ins" of production, and has had higher than expected operating costs. Future gas exploration and production activity around Deep Panuke and other Nova Scotia gas fields is uncertain. Absent material changes in gas exploration and production successes in the Maritimes, New England buyers will need to replace this portion of its fuel supplies.

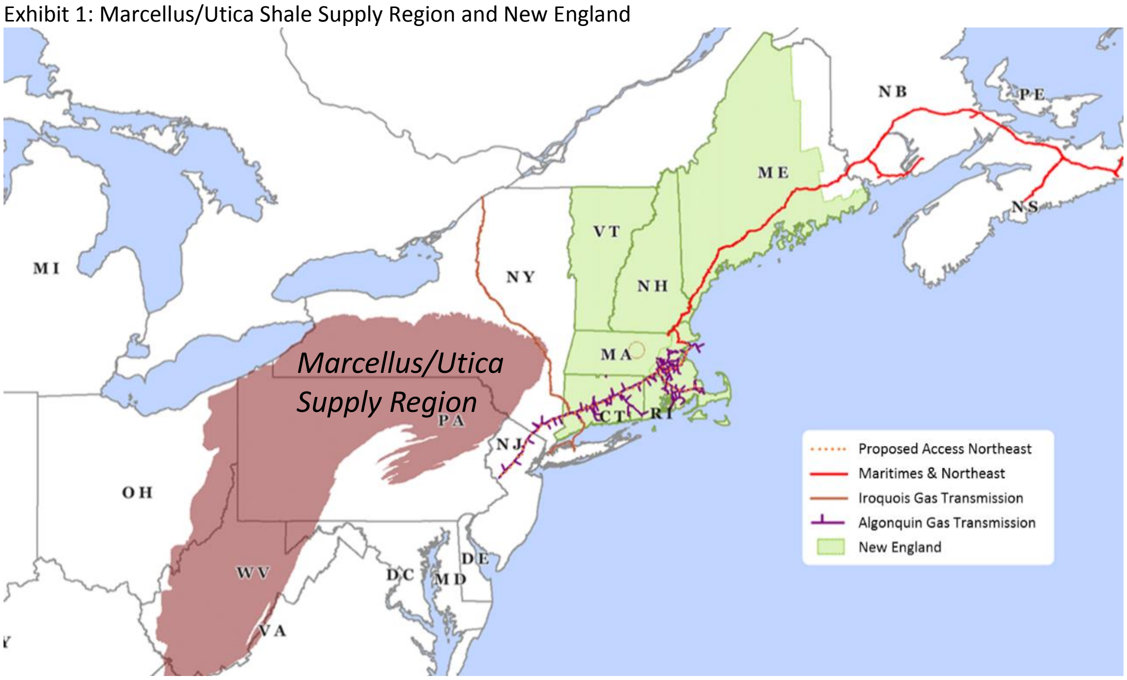
It is important to note that declining gas production in the Canadian Maritimes will likely prompt gas consumers in those provinces to turn to gas imports from New England to meet their heating and power generation needs.[10] This would lead to increased competition for already scarce pipeline capacity and gas supply resources for New England.

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. As a result, New England must compete with the rest of the world to have LNG spot cargoes available on peak days. This can result in extremely high gas prices, or no gas at all, depending on the availability of spot cargoes. Even during the 2013-2014 winter, when spot prices spiked to $78/MMBtu, very few spot cargoes were delivered into New England terminals.

Expected growth in the Marcellus/Utica production basins provides a reliable and economic supply source to New England and are located very close to the region

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 (Exhibit 1) increases from its current output of 17 Bcf/d to a projected 37 Bcf/d by 2035 (as shown by the right axis of Exhibit 2).

Exhibit 1: Marcellus/Utica Shale Supply Region and New England

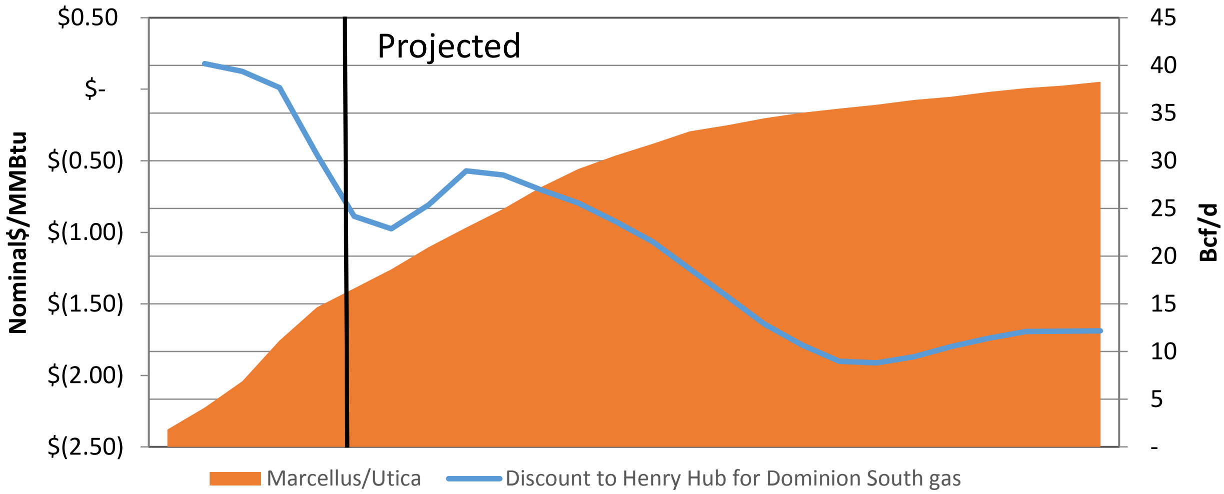


Source: ICF International, Ventyx

10 See also: "The Future of Natural Gas Supply for Nova Scotia", ICF International, Prepared for Nova Scotia Department of Energy, March 28, 2013.

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. As shown on the left axis of Exhibit 2, 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 $1.00. ICF projections show that, as a result of declining production costs, the discounted spread will widen further to more than $1.50/MMBtu. At these prices, the Appalachian Basin is among the lowest priced gas supply sources on the continent.

Exhibit 2 - Historical and Projected Marcellus/Utica Production and Dominion South Point to Henry Hub Basis[11]



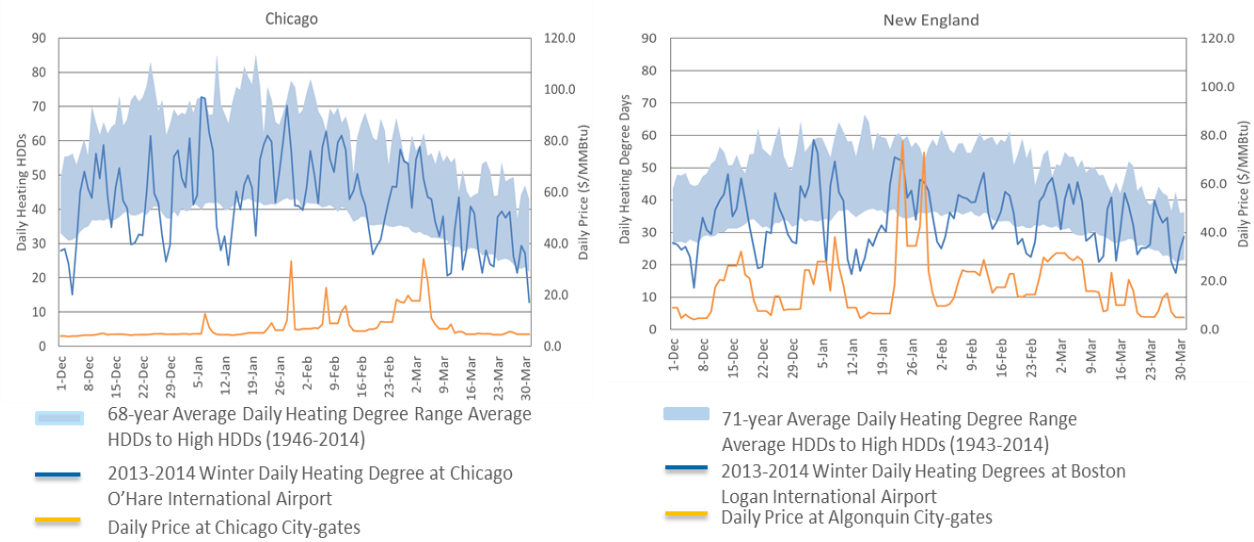
Source: ICF International, SNL

Lack of gas infrastructure to fuel power generation makes New England consumers especially vulnerable to cold weather situations

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. Exhibit 3 shows the comparable weather and natural gas prices in New England and Midwest during this past winter. The US Midwest region experienced the coldest winter in more than 60 years. This is reflected by the actual daily heating degree days[12] (HDD), represented by the blue line which is repeatedly approaching the top of the blue shaded range representing the past 68 years. On the other hand, New England was only moderately colder than normal with the blue daily HDD line positioned mostly in the middle of the historical range. Natural gas prices in the Midwest, however, were much more stable than those in New England primarily because the Midwest has a multiplicity of supply source options and adequate pipeline capacity on several pipeline systems. This behavior signals the first consequence of New England's winter gas capacity inadequacy - extremely high and volatile natural gas prices.

[11] Basis presented here is Dominion South Point price minus Henry Hub price.
[12] Heating Degree Days is calculated as 65 minus the average temperature of the day.

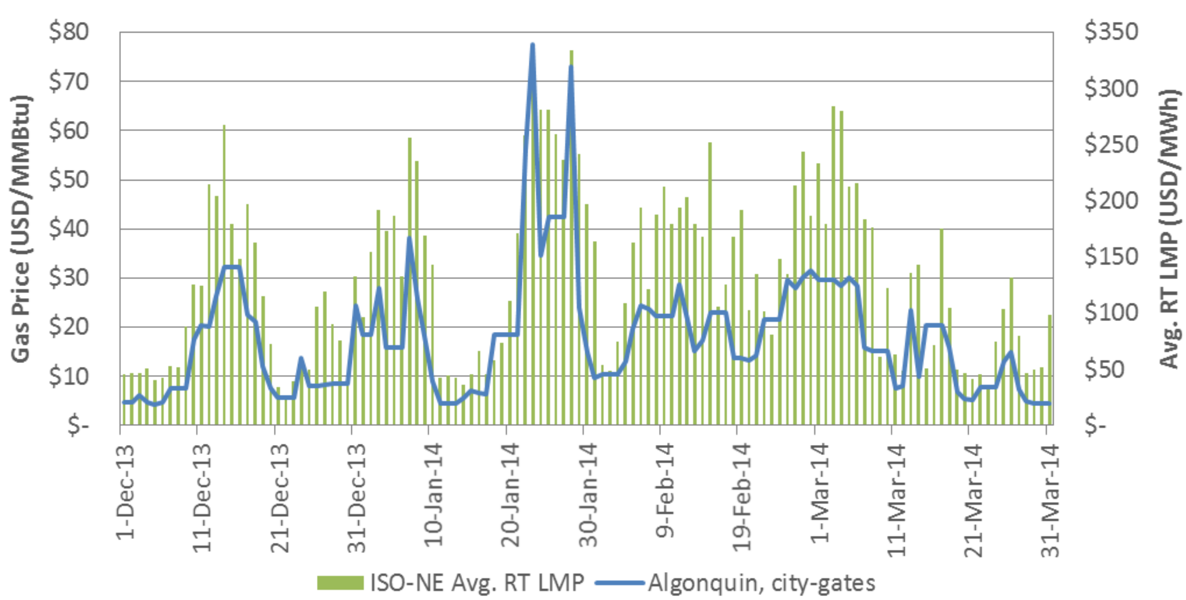
Exhibit 3: Winter 2013-2014 Natural Gas Spot Price Comparison



Source: ICF International, SNL, NOAA

Exhibit 4 shows the second and potentially more damaging consequence of the natural gas capacity inadequacy. In New England, power prices are closely correlated with natural gas prices, so electric prices last winter also reached unprecedented levels as a result of the natural gas price spikes. This tight correlation between gas and electric prices is expected to continue with the increasing dependency of the power grid on natural gas supply and delivery infrastructure.

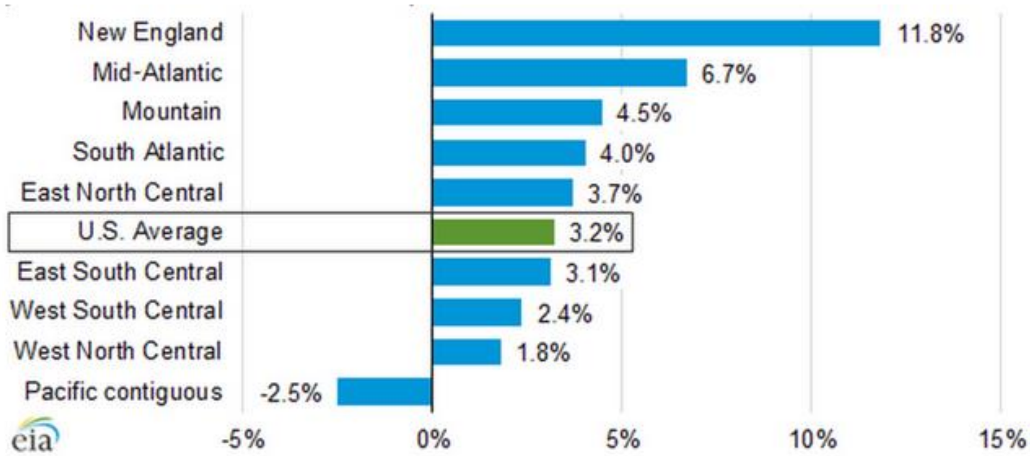
Exhibit 4: Comparison of New England Gas and Wholesale Power Prices



Source: ICF International, SNL

As a result, this extreme sensitivity to weather events may become very costly for New England's electricity consumers if left unaddressed. For December 2013 through March 2014, New England paid an estimated $6.8 billion for wholesale power, $3.2 billion above the prior year's level. New England residential electric customers experienced the highest single-year growth rate in the country.

Exhibit 5: Percent Change in Average Residential Electricity Prices, First Half 2014 versus First Half 2013



Source: Energy Information Administration http://www.eia.gov/todayinenergy/detail.cfm?id=17791

In addition, almost all New England utilities have had a drastic increase in residential retail rates for the first half of 2015, with increases ranging from 7 to 100 percent, as shown in Exhibit 6.

Exhibit 6: Average Residential Electricity Rates – Energy Only

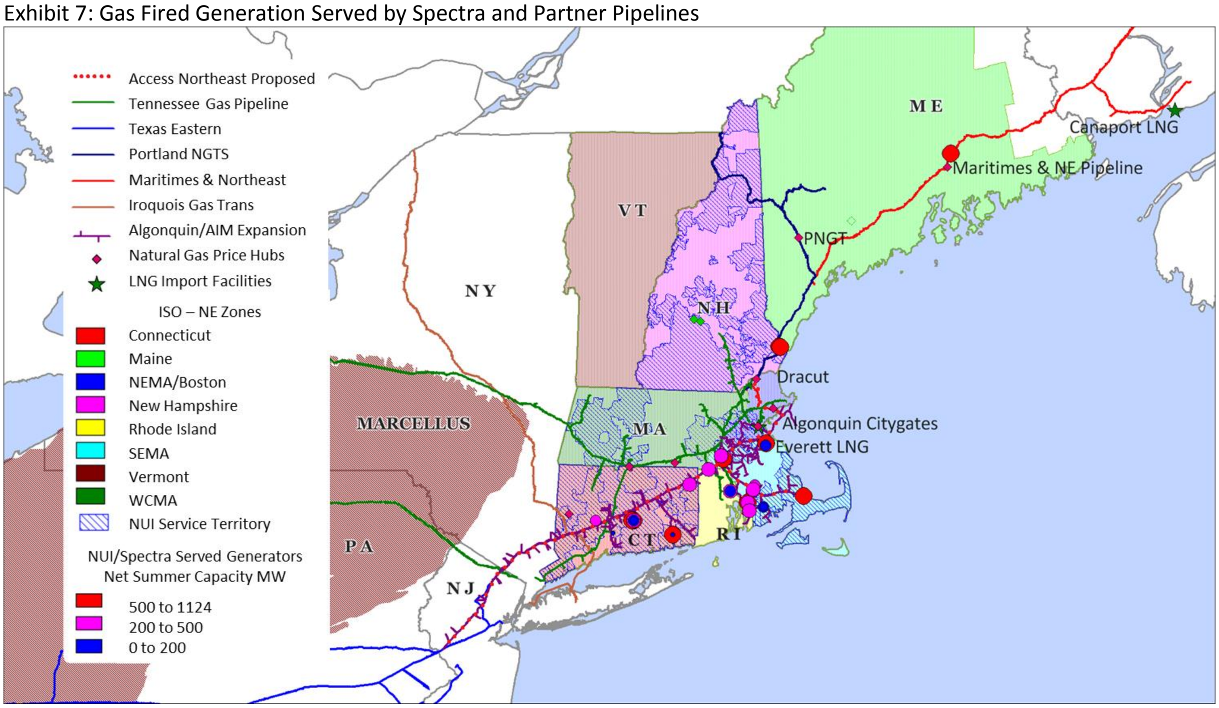
Residential Rates	Energy Rate (c/kWh)		% Change	Current Period
	Prior Rate	Current Rate		
Connecticut				
CL&P	10.0	12.5	25%	Jan '15 – Jun '15
United Illuminating	8.7	13.3	53%	Jan '15 – Jun '15
Massachusetts				
NSTAR	9.4	15.0	60%	Jan '15 – Jun '15
WMECO	8.8	14.0	58%	Jan '15 – Jun '15
National Grid	8.3	16.2	96%	Nov '14 – Apr '15
Fitchburg	8.5	14.1	66%	Dec '15- May '15
New Hampshire				
PSNH	9.9	10.6	7%	Jan '15 – Dec '15
Unitil	8.4	15.5	85%	Dec '14 – May '15
Liberty	7.7	15.5	100%	Nov '14- Apr '15
NH Elec Coop	9.0	11.6	29%	Oct '14 - Apr '15

Source: Eversource Energy

Access Northeast will enhance New England's grid reliability, complement the ISO-NE's market improvements to incentivize generation availability, and support the region's renewable energy goals

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.[13] 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. Exhibit 7 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.[14] By providing secure fuel supplies to these generators, Access Northeast could improve electric reliability across the grid.

Exhibit 7: 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 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

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

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. 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, 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. Once again, the 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.

New England could have saved $2.5 billion in wholesale electric costs had a project like Access Northeast been in operation during the 2013 – 2014 winter

In addition to enhancing the area's electric reliability, additional firm supplies created by a project like Access Northeast will significantly reduce regional gas and electricity prices, especially during winter months when lack of gas supply during peak days has led to high and volatile gas prices. ICF estimates that a project like Access Northeast could have eliminated gas and electric price spikes on 49 days during this past winter and saved $2.5 billion in wholesale energy costs for New England's electric consumers.

ICF has analyzed historical flow and price data for the "Polar Vortex winter" of 2013 - 2014 to illustrate the potential impacts that a project like Access Northeast could have had during the winter of 2013-2014. Daily load factors on pipelines serving New England from New York, namely Tennessee Gas Pipeline (Tennessee) and Algonquin, averaged 89 percent from December 2013 to March 2014, and load factors on price spike days frequently exceeded 95 percent. An additional 500 MMcf/d of capacity, such as is proposed by Access Northeast, could have reduced the average load factor to 75%. Additionally, the pipeline load factors on peak winter days could have been further reduced with Access Northeast's proposed capability to use strategically located LNG injection points on the Spectra pipeline systems, as illustrated in Exhibit 8. When pipeline load factor is at or below 75% of capacity, New England natural gas price spikes and associated electric price spikes are much less likely to occur[15].

Exhibit 8: Hypothetical Load Factor Reduction with Access Northeast

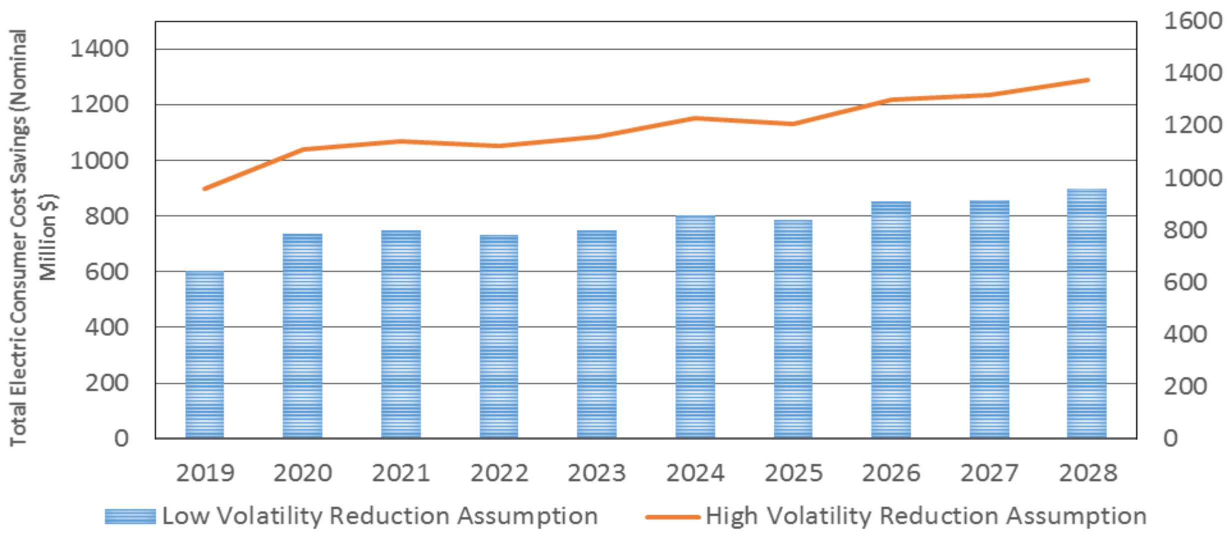
January 23, 2014						
Actual			Hypothetical with Access Northeast			
Flows MMcf/d	Capacity MMcf/d	Load Factor %	Capacity MMcf/d	Storage Dispatch MMcf/d	Reduced Flows MMcf/d	Load Factor %
2479	2761	90%	3261	83	2396	73%

[15] Historical data analysis indicates that New England prices tend to spike up when pipeline load factors exceed 75% of existing infrastructure capacity, which is consistent with the conclusions of the NESCOE study.

<u>A project like Access Northeast generates $780 million to $1.2 billion savings for New England Electric consumers under normal weather conditions</u>

ICF estimates that, on average, a project like Access Northeast could save New England electric consumers $780 million to $1.2 billion per year over its first ten years of operation (2019 – 2028). Reduced wholesale energy prices resulting from reduced gas prices lower the cost of every MWh of energy consumed in the region, so all electric consumers will benefit from this cost reduction. It is critical to note, however, the price correlation between natural gas and power can only be realized if power plants have access to natural gas supply, which is a primary benefit that Access Northeast provides. Exhibit 9 shows that annual electric cost savings resulting with Access Northeast rises from $600 million to $1.4 billion over time.

Exhibit 9: New England Electric Consumer Cost Savings



Source: ICF International

The extreme price volatility of natural gas in winter was partly driven by generators' lack of firm access to fuel. The volatile market price for gas on a daily basis results from the scarcity pricing effect where generation buyers were faced with little to no market liquidity (a "seller's market"). ICF's volatility analysis is intended to capture the asymmetric nature of the "gas for power" market in New England - prices can go very high, but tend to decline only modestly. ICF's estimates of volatility reduction are conservative, by assuming that a project like Access Northeast results in "reduction" and not "elimination" of volatility, which could have resulted in larger economic benefits such as the $2.5 billion estimated for the 2013-2014 winter.

In addition to the projected savings to consumers, an infrastructure project like Access Northeast will improve market liquidity by providing the infrastructure needed to ensure firm gas access for power generation and, therefore, create a more balanced and efficient "gas for power" market. The Access Northeast infrastructure will "de-bottleneck" the gas supply market for generation much like a transmission line removes market price separation along a constrained electric interface.

The annualized cost of the Access Northeast project assessed in this analysis is approximately $400 million a year.[16] ICF estimates that the project would potentially produce net savings of $380 million to $800 million a year to New England's electric consumers. This estimate assumes that the project is constructed following the funding mechanism that the electric distribution companies proposed to NESCOE[17]. Under such a mechanism, New England's electric consumers would 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). ICF also estimates that the majority of the $2.4 billion investment required for the project could be recovered from the cost savings realized from a single winter like 2013/14.

Access Northeast's cost savings increase by more than 25% if extreme winter weather conditions occur along with a nuclear plant outage

ICF has assessed the benefits of Access Northeast under a "1-in-20 year" design winter and also assuming that 1,000 MWs of base load units are not available during the 2018-2019 winter (this is also a condition evaluated by ISO-NE and carries a high risk to electric reliability without new gas infrastructure). This results in more dramatic natural gas and wholesale electricity price reductions. ICF estimates that during the five-month winter period from November 2018 through March 2019, cost savings to the area's electric customers would be approximately $1.1 billion dollars, 25 percent higher than the high volatility reduction under normal weather conditions.

Access Northeast promotes greater reliability and mitigates the risks of costly electric grid disruption

The cost savings estimated by ICF in preparing this study and report focus solely on the benefits that additional infrastructure have on fuel supply costs and, in turn, the cost of producing electricity. Another and potentially much greater financial benefit is gained by avoiding potential direct and indirect economic consequences from disruptions to electric grid services. Although beyond the scope of this study, other sources have shown that disruptions to electric services can be multiples of the billions of dollars in fuel cost savings we identify.

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[16] ICF estimated the levelized cost for the power generation solution based on a $2.4 billion capital investment requirement.

[17] http://www.nescoe.com/uploads/GasforElectricReliabilityGraphic_April2014.pdf

Study Background

The ISO-NE Perspective

Over the past decade, the New England power market has experienced a rapid shift towards gas-fired generation, which has created challenges for ISO-NE regarding electric system reliability. Although the region has expanded pipeline infrastructure as demand from gas LDCs customers has grown, there has been no equivalent investment to ensure that gas is available for power plants as New England's reliance on gas-fired generation has increased significantly. Generators' lack of firm pipeline capacity contracts has been identified as a key risk by ISO-NE. Under the pipeline regulatory system imposed by FERC, interstate gas pipelines only build new or increased pipeline capacity if shippers are willing to commit to long-term firm contracts for the capacity rights. Without long-term firm contracts, pipeline capacity will not be added into New England.

LDCs contract for firm pipeline capacity based on potential peak day demand of their firm service customers under extreme winter weather conditions, referred to as a "design day" and buy their gas supplies under a portfolio of supply contracts and delivery points in the gas production areas served by their pipeline transport providers. Electrical generators in vertically integrated power markets (primarily in the Midwest, southern states, and some western states) will make long-term pipeline contracts because they are usually permitted to pass the costs of the capacity contracts through to their electric customers. However, in ISO/RTO markets like New England, generators are unwilling to take the risk of entering in long-term contracts absent any certainty that they will be able to recover those costs. As a result, most gas-fired generators in New England have made no long term commitment and rely on non-firm, interruptible capacity (IT) services and spot market purchases of natural gas supplies.

During the summer months, New England LDC loads are low and IT services are readily available. However, in the winter months (and particularly on cold winter days when firm LDC demand is highest), IT services become scarce, leading to sharp increases in regional spot gas prices and concerns about meeting minimum fuel requirements needed to avoid electric system disruptions. The 2013/14 Winter Reliability program encouraged oil and dual-fuel generation to stockpile oil reserves though out-of-market payments. With FERC approval, ISO-NE has implemented a similar Winter Reliability program for the winter of 2014/15. However, in its order approving the new 2014/15 program, FERC stated, "we expect ISO-NE to abide by its commitment to develop a long-term, market-based solution to address winter reliability issues."[18]

As part of its effort to look for long-term solutions, ISO-NE has engaged ICF for three separate studies since 2011 to evaluate the availability of gas supplies to New England electric generators during peak winter demand periods through 2020. The three ICF studies are:

1) Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs ("Phase I"), analysis completed June 2012[19]

[18] http://www.ferc.gov/CalendarFiles/20140909165718-ER14-2407-000.pdf
[19] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public_slides.pdf

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2) Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II ("Phase II"), analysis completed December 2013[20]
3) Winter 2013/14 Benchmark and Revised Projections for New England Natural Gas Supplies and Demand ("Winter Benchmark"), analysis completed April 2014[21]

A similar analytic approach was used in the Phase I and Phase II studies. First, ICF evaluated the total gas supplies available to New England consumers (from firmly contracted interstate pipeline capacity, send out from LNG import terminals, and LDC-operated peak-shaving facilities) on a peak winter day. Next, ICF projected the aggregated design day firm load for the New England LDCs, based on data provided by the LDCs for use in the study and LDC filings with their state public service commissions. To arrive at gas supplies remaining for New England's electric generators on a peak winter day, ICF subtracted the LDC firm design day load from the total regional gas supplies. Separately, ISO-NE modeled multiple scenarios for gas generation fuel requirements, based on various combinations of gas prices, projected electric load, availability of non-gas generation, and other variables. The ISO-NE projections for generator gas demand were compared to the remaining supply; where projected demand is greater than the remaining supply, this is referred to as a gas supply deficit. The Phase II study concluded that by the winter of 2019-2020, gas supply deficit would range from 250 to 1,100 MMcf/d under the Phase II Retirements scenarios, which did not include ISO-NE's revised projections for electric load reductions due to energy efficiency.[22] However, even in cases including new energy efficiency projections that reduce electric load growth and gas demand, the Phase II still projected gas supply deficits of from 200 to 800 MMcf/d.[23]

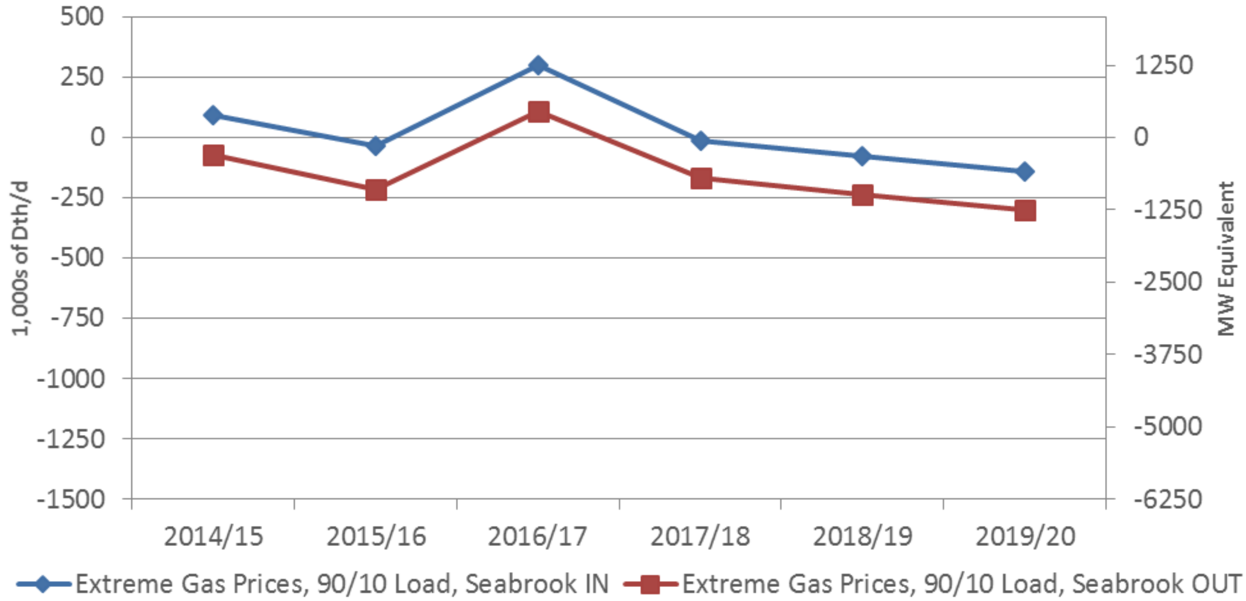
For the most recent Winter Benchmark study, ISO-NE asked ICF to examine gas system performance during the winter of 2013/14 (particularly during the January 2014 polar vortex events), and based on this new data, revise its Phase II projections for New England natural gas supplies, firm LDC demand, and gas supplies remaining for electric generators. ICF collected data on daily pipeline flows throughout the winter, and the Northeast Gas Association (NGA) provided send out data from their member LDCs for four of the peak demand days in January. ISO-NE provided a total of nine new gas demand projections, based on its dispatch analysis using results from the latest Forward Capacity Auction (FCA 8), and various combinations of gas prices, load assumptions, and nuclear outages.

The cases ISO-NE deemed to be most relevant in the Winter Benchmark study were those using "extreme" (~$23/MMBtu) gas prices, since these cases are most representative of spot prices observed in New England when gas supplies are constrained and oil-fired units frequently become the marginal supply.

[20] While the Phase II study was complete in 2013 and a draft report was issued in December 2013, the final version of the report was posted on ISO-NE on November 20, 2014; see: http://www.iso-ne.com/static-assets/documents/2014/11/final_icf_phii_gas_study_report_with_appendices_112014.pdf
[21] http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/apr292014/a3_icf_benchmarking_study.pdf
[22] Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near Term Electric Generation Needs: Phase II, ICF International (2014), page 21, Exhibit 4-6.
[23] Ibid.

Exhibit 10 shows the projected gas deficits for peak winter days through the winter of 2019/20; points below 0 on the y-axis represent supply deficits.[24]

Exhibit 10: Power Sector Winter Peak Day Supply Deficits



Source: ISO-NE Planning Advisory Committee presentation, April 29, 2014

Even assuming extreme gas prices and heavy reliance on older more expensive oil-fired generation, the electric system is still expected to have a gas deficit of between 140 and 300 MMcf/d (equivalent to 600 and 1,300 MW) by the winter of 2019/20, meaning electric system reliability will remain at risk without additional gas supplies into the region. As shown in the Phase II study, the supply gap is expected to be much larger if gas prices are less extreme. Gas supply to ISO-NE generation would need to provide an additional 1.1 Bcf/day in order to fuel as much as 5,700 MW of generation and allow for cost efficient and reliable operations.

With extreme gas prices at $23/MMBtu and above many oil units are in merit, which reduces gas-fired generation, producing a "lower" deficit for natural gas fired generation capacity. However, while the ISO-NE dispatch analysis assumes oil supplies are available, experience from the winter of 2013/14 indicates that this might not be the case. Generators had stockpiled oil prior to winter (due to the ISO-NE Winter Reliability program requirements), but by February of 2014 most generators were down to two days of oil supplies. In a filing with FERC, ISO-NE stated that during this winter2013/14:

> "Those [oil-fired generating stations] that tried to replenish their inventory reported difficulties in both procuring and transporting oil. Oil was unavailable given the increased demand from both the heating and power sectors and reduced supply following years of reduced demand. Even when oil was available, barges to transport the oil were in short supply due to high demand all along the East Coast. When they were

[24] The deficit reduction in the winter of 2016/17 is due to the planned Algonquin AIM and Tennessee Connecticut pipeline expansions in November 2016; these were the only pipeline capacity expansions assumed in the Winter Benchmark analysis.

available, barges had difficulties with frozen and shallow water conditions. Trucks were also limited, and commercial drivers' license requirements restricted hours per day of work (although the license requirement was loosened in Massachusetts at the ISO's request)."[25]

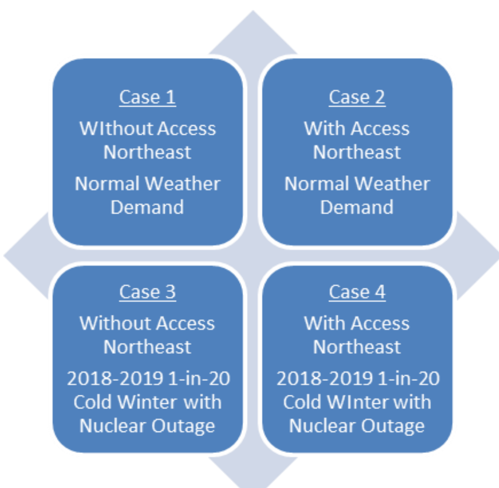
While ISO-NE's Winter Reliability program encourages less reliance on gas-fired generation, the resulting increase in dependence on oil-fired generation can also present reliability risks, demonstrated by the difficulties replenishing oil supplies this past winter. Additionally, the increased dependence on oil-fired generation can result in high electricity rates to customers (such as those experienced during winter 2013/14) as summarized earlier in this report. Consistent with the design of the Access Northeast project, firm pipeline capacity, from both more firm transport from stable gas sources west of New England and access to supplemental LNG supplies from strategically located facilities in New England, will provide enhanced power supply reliability.

Purpose of This Study

The purpose of this study is to assess the impact to electric system reliability and estimate the potential cost savings to New England electric consumers from the proposed Access Northeast project.

ICF's analyses focused on four model runs – one scenario assuming the average normal weather conditions from 2019 through 2028 with and without Access Northeast, and a second scenario assuming a 2018-2019 cold winter season with a large nuclear outage, as shown in Exhibit 11. ICF also provides qualitative assessments on the proposed project's potential non-economic benefits, including enhancing the electric system reliability and supporting renewable generation.

Exhibit 11 : ICF Analysis Overview



ICF's analyses and findings draw from years of experience consulting on North American natural gas and electric markets, and the proprietary software tools and data bases developed for that purpose. For this analysis, ICF utilized a suite of analytical tools –Gas Market Modeling (GMM©), ICF's Integrated Planning

[25] ISO-NE ISO New England Inc., Docket No. ER14-2407-000 Winter 2014-15 Reliability Program (Part 1 of 2) http://www.iso-ne.com/regulatory/ferc/filings/2014/jul/er14-2407-000_win_rel_pro_7-11-2014.pdf

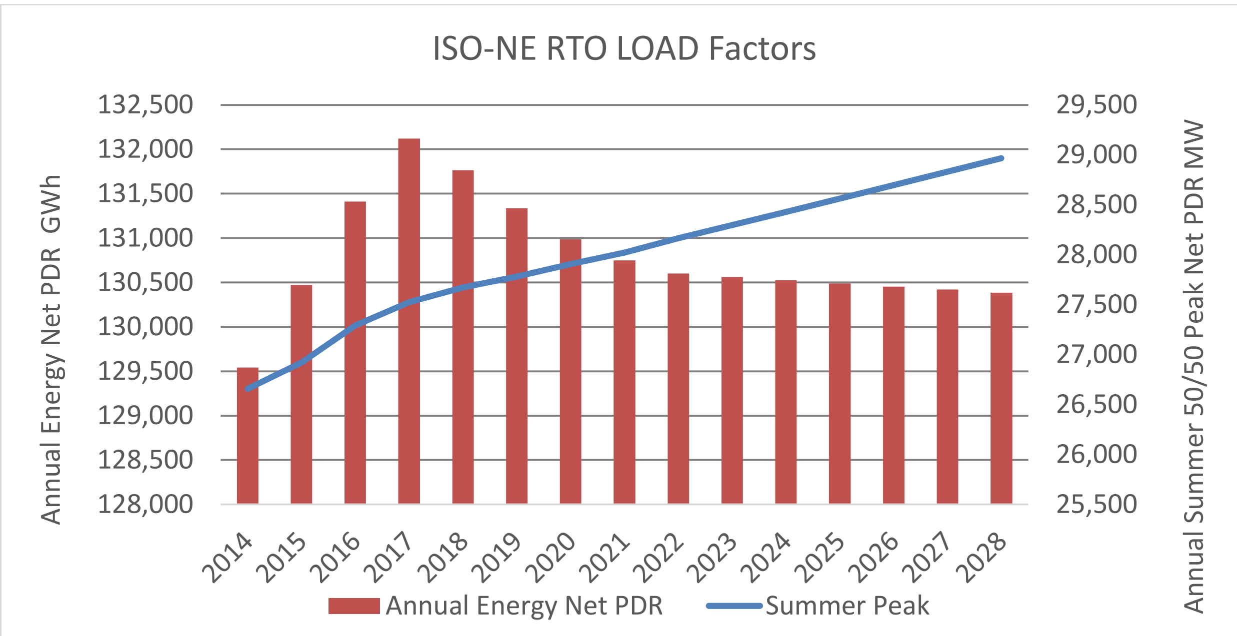
Model (IPM®), and GE's Multi Area Production Simulation (MAPS) –through an iterative and integrated process.

Analytic Assumptions

Electric Load Growth

For electric load growth in New England, ICF utilizes the 2014 ISO-NE CELT report's net of Passive Demand Response ("PDR") energy load forecast extrapolated through 2028. The projection assumes that New England's annual net energy load grows through 2017 and declines until 2023 and remains flat afterwards as seen in Exhibit 12. This load growth projection reflects significant amount of energy efficiency gains over time to offset the load growth resulted from population growth and economic developments.

Exhibit 12: ISO-NE RTO LOAD Factors



Source: ICF International

Capacity Retirements and Builds

In the analysis, ICF assumes that approximately 2,800 MW of coal, oil, and nuclear generation capacity in ISO – NE is retired by 2018 as shown in Exhibit 13.

Exhibit 13 – ISO – NE Firm Retirements

Plant Name	Capacity Type - Sub Type	Retirement Date	Capacity Modeled(MW)
Vermont Yankee	Nuclear - Nuclear	01-Oct-14	604
SALEM HARBOR	Coal, Oil/Gas Steam	30-May-14	581
Bridgeport Station	Oil/Gas Steam - Heavy Oil	01-Jan-17	130
Brayton PT	Oil/Gas Steam - Heavy Oil, Combustion Turbine, Coal	31-May-17	1500

Source: ICF International

For this analysis, ICF assumes that the Footprint Power facility (700 MW rating) comes online in January 2017. In addition, a 500 MW of combined cycle facility is assumed to be constructed in 2023 to replace retired capacities.

Renewables

ICF assumes all renewable portfolio standards ("RPS") in the New England states are met according to the proposed timeline. For Massachusetts, the RPS requires 22 percent of energy from renewable resources by 2020 and an additional 1 percent each year thereafter. Connecticut, 27 percent by 2020; New Hampshire, 24.8 percent by 2025; Rhode Island, 16 percent by 2020 and Maine, 30 percent by 2020. ICF assumes 800 MW of wind will be built through 2028. 1,500 MW of solar and approximately 150 MW of landfill and biomass capacity will also be added to serve ISO-NE.

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 place. ICF also assumes that the EPA will not have an alternative to current the Clean Air Interstate Rule (CAIR) regulations, and that CAIR remains in place through 2017. In 2018, ICF assumed standards tighten to the Cross State Air Pollution Rule (CSAPR) Phase II requirements. Furthermore, ICF considers a national CO_2 cap and trade program starting in 2020 at $1/ton and increasing to $16.6/ton by 2028. However, on the regional level, the analysis assumes the existing CO_2 market for Northeastern and Mid-Atlantic states[26] under the Regional Greenhouse Gas Initiative ("RGGI") program remains in place[27] and is gradually integrated into the federal program.

ICF's CO_2 forecast reflects a probability weighted assessment of several alternative GHG mitigation policies. Exhibit 14 shows the RGGI CO_2 expected allowance prices in New England increases from $5.2/Ton to $16.6/Ton by 2028.

[26] Includes MD, CT, DE, ME, MA, NH, RI, VT, and NY.

[27] RGGI CO_2 program is assumed to be subsumed by National CO_2 program by 2026. Inflation used beyond 2013 is 2.1% annually. Therefore the values presented here beyond 2025 are actually national CO_2 numbers.

Confidential and proprietary to ICF International

Exhibit 14: Carbon Pricing Assumptions

Year	RGGI: CO_2 Expected Allowance Prices (Nom$/Ton)
2014	5.2
2015	6.3
2016	7.5
2017	8.9
2018	9.1
2019	9.3
2020	11.4
2021	11.6
2022	11.8
2023	12.1
2024	12.3
2025	12.6
2026	13.3
2027	14.9
2028	16.6

Source: ICF International

Impact on System Reliability

Access Northeast will increase ISO-NE's electric system reliability by directly providing firm natural gas fuel for gas fired power generators. As discussed earlier, the most recent ISO-NE study performed by ICF last year identified that potential capacity needs for the region range from 250 MMCf/d to 1.1 Bcf/d for peak winter days under different assumptions.

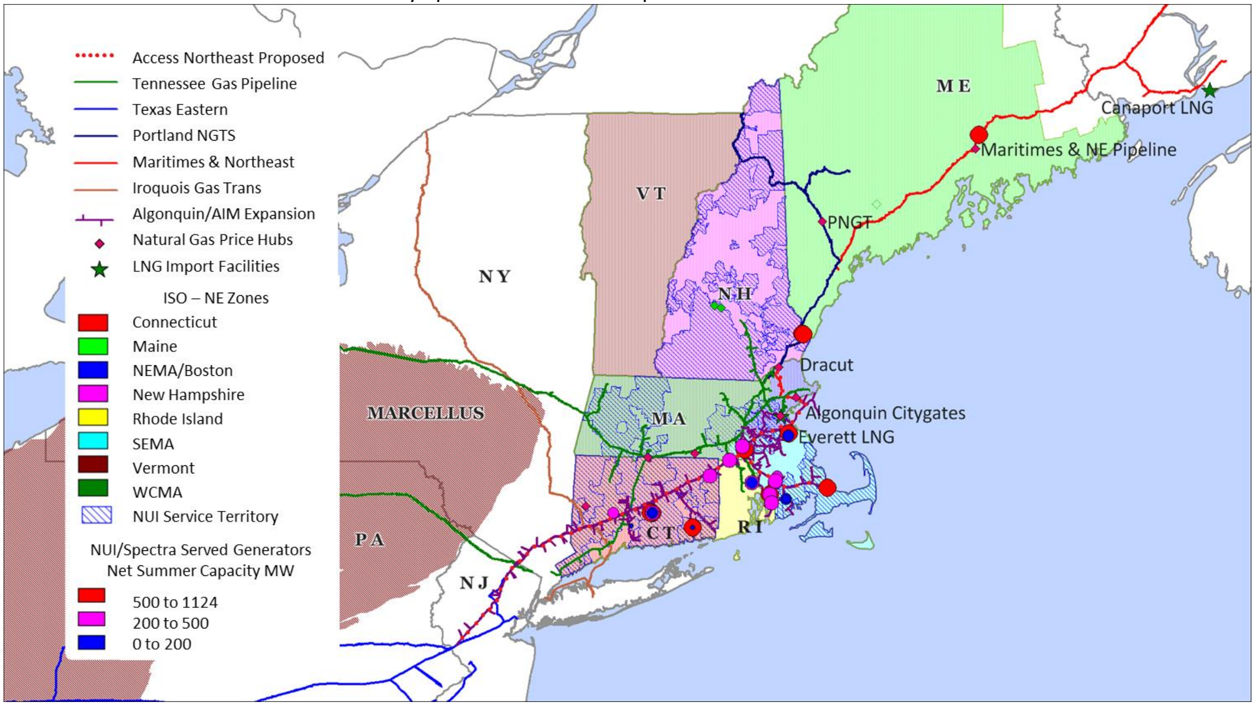
The Mass DOER study, recently completed by Synapse Energy, analyzed a suite of scenarios and concluded that in order to balance supply and demand for natural gas in Massachusetts in 2020, there is a hypothetical natural gas capacity need of 25 billion Btu per peak hour to 33 billion Btu per peak hour (0.6 Bcf per day to 0.8 Bcf per day).[28] The estimated need for pipeline capacity exists even under the low demand scenario with the assumption of a new transmission project that imports 2,400 MW of Canadian hydroelectric power into Massachusetts. The low demand scenario is based on the assumption that Massachusetts implements all of the alternative resources deemed technically and economically feasible and practically achievable.

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. Exhibit 15 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[29]. By providing secure fuel supplies to these generators, Access Northeast could significantly improve electric reliability across the grid.

[28] Massachusetts Low Demand Analysis, slide 28, http://synapse-energy.com/project/massachusettslow-demand-analysis.

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

Exhibit 15: 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 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. 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.

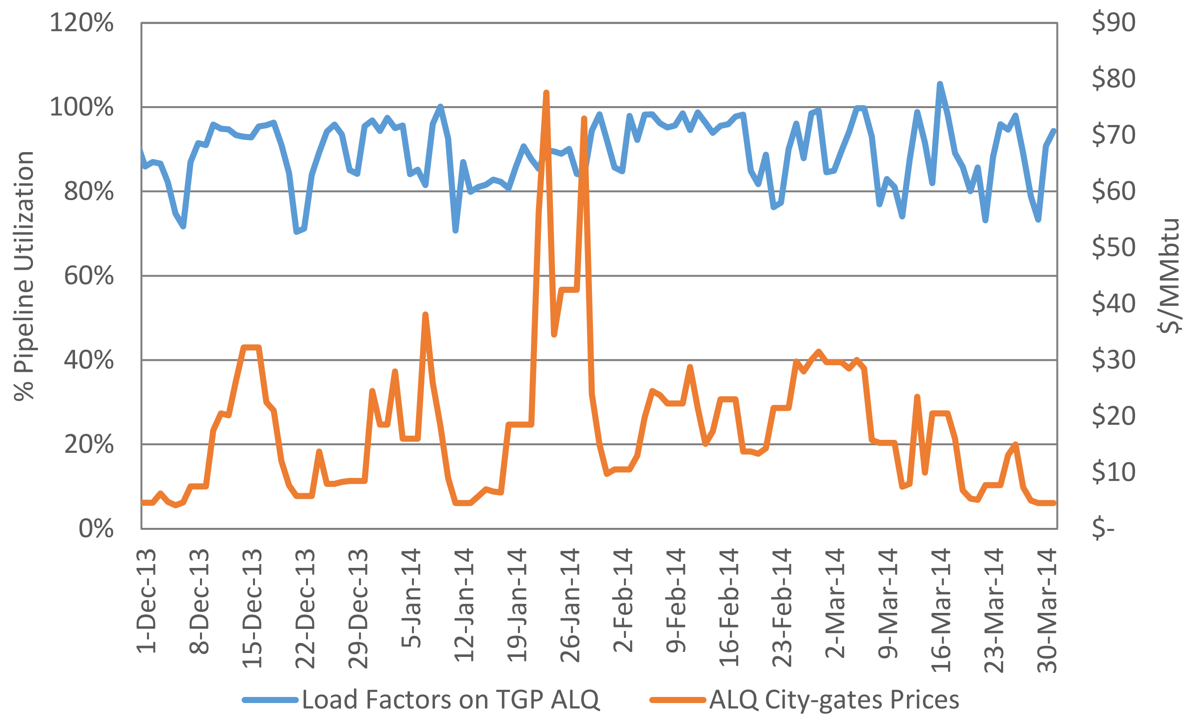
In addition, New England states have ambitious goals for deployment of renewable generation. Due to the intermittent nature of wind and solar generation, additional quick response gas-fired generation is needed as renewables' share of total generation increases. Once again, the Access Northeast will 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.

Hypothetical Impact of Project on Winter 2013/2014

ICF has analyzed historical flow and price data to illustrate the potential impacts that a project like Access Northeast could have had during the "polar vortex winter" of 2013-2014.

As shown in Exhibit 16, daily load factors on pipelines serving New England from New York - namely Tennessee Gas Pipeline (Tennessee) and Algonquin - averaged 89 percent from December 2013 to March 2014, and load factors on price spike days frequently exceeded 95 percent.

Exhibit 16: Daily Load Factors on TGP and ALQ during winter 2013-2014 and New England Natural Gas Prices

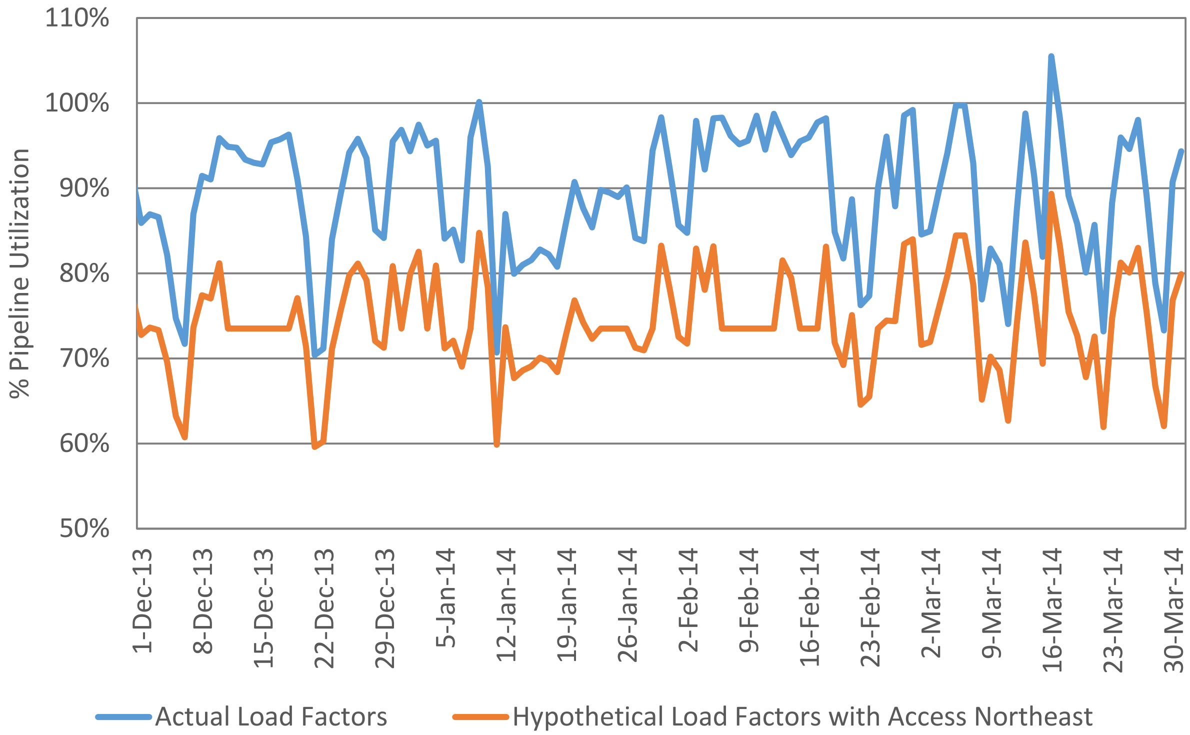


Source: ICF International, LCI

An additional 500 MMcf/d of capacity, such as is by Access Northeast analyzed in this study, could have reduced the load factors by increasing available capacity. Additionally, the dispatch of Access Northeast's proposed LNG capabilities on peak winter days could have further reduced pipeline load factors. Exhibit 17 shows the actual load factor and the hypothetically reduced load factors for introducing the Access Northeast project. Based on the assumption that the gas price spikes and associated electric price spikes would be eliminated when pipeline load factors are at or below 75 percent[30], ICF estimates that a project like Access Northeast could have eliminated gas and electric price spikes on 49 days from December 2013 through March 2014, saving $2.5 billion in wholesale energy costs for New England's electric consumers.

[30] Historical data analysis indicates that New England prices tend to spike up when pipeline load factors exceed 75% of existing infrastructure capacity, which is consistent with findings of the NESCOE study.

Exhibit 17: Actual Pipeline Load Factors and Hypothetical Reduced Load Factors with Access Northeast



Source: ICF International

The estimated cost savings were extraordinary for winter 2013-2014, because the polar vortex conditions have impacted a very large US geographic area (including the Northeast, Southeast, and Mid-west simultaneously) that drove up the demand for natural gas throughout the natural gas transportation systems.

Cost Savings - Normal Weather Scenario

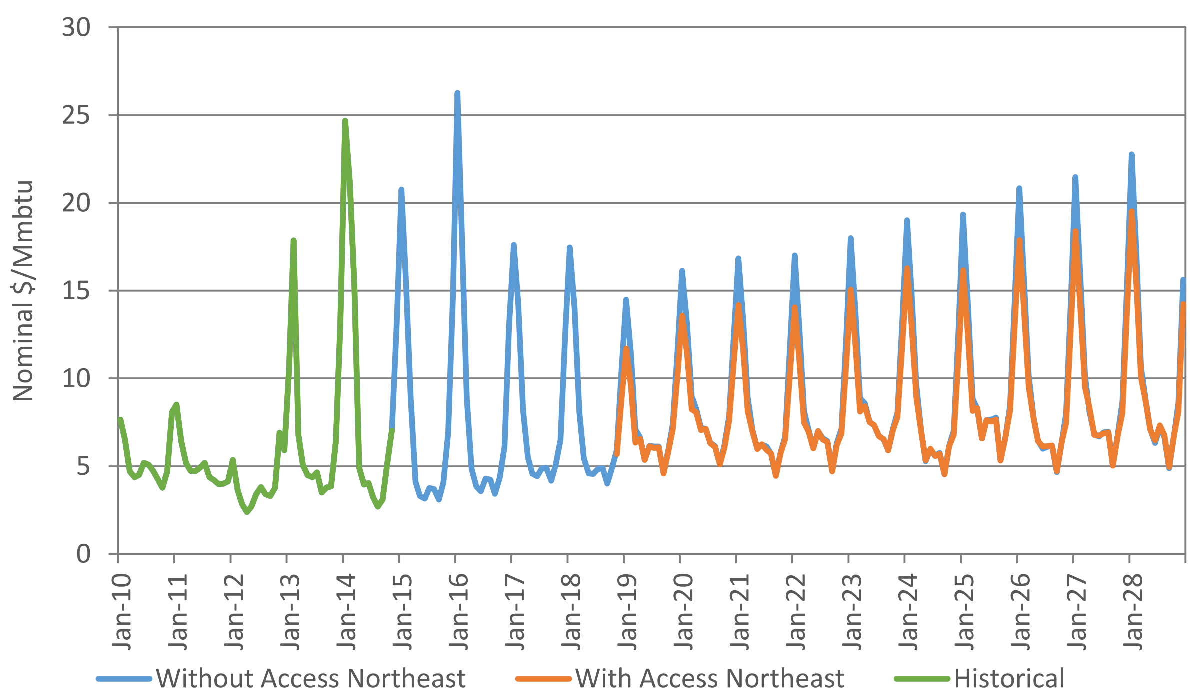
ICF estimates the economic impact of Access Northeast by running GMM and IPM models under normal weather conditions with and without Access Northeast and compares the difference between natural gas prices and electricity prices. The price reduction is used to calculate the market impact and potential cost savings to New England's electric consumers before estimating savings from reduced price volatility. The project's impact on natural gas price volatility and subsequent reduction to the electric price spikes are then estimated separately utilizing a statistical approach.

Natural Gas Price Impact (excluding volatility)

Exhibit 18 shows that without Access Northeast, under normal weather conditions, ICF projects gas prices in New England will briefly exceed the level reached in last winter. Incremental capacity expansions (such as AIM, Tennessee's Connecticut Expansion, Spectra's Atlantic Bridge, and other projects to meet LDCs' load growth) will lower the price down to \$15/MMBtu. It then steadily increase over time and exceed \$20/MMBtu by January 2026 when more gas is needed for generation and supply from East Canada is no longer available. Access Northeast reduces January price by \$2.80 – 3.20/MMBtu for the entire study period.

Even before taking the impact of volatility into consideration, ICF projects that Access Northeast will significantly reduce natural gas prices during peak winter months. On average, peak winter month prices will be approximately \$3/MMBtu lower with Access Northeast.

Exhibit 18: New England Natural Gas Price Forecast (excluding volatility reduction benefits)

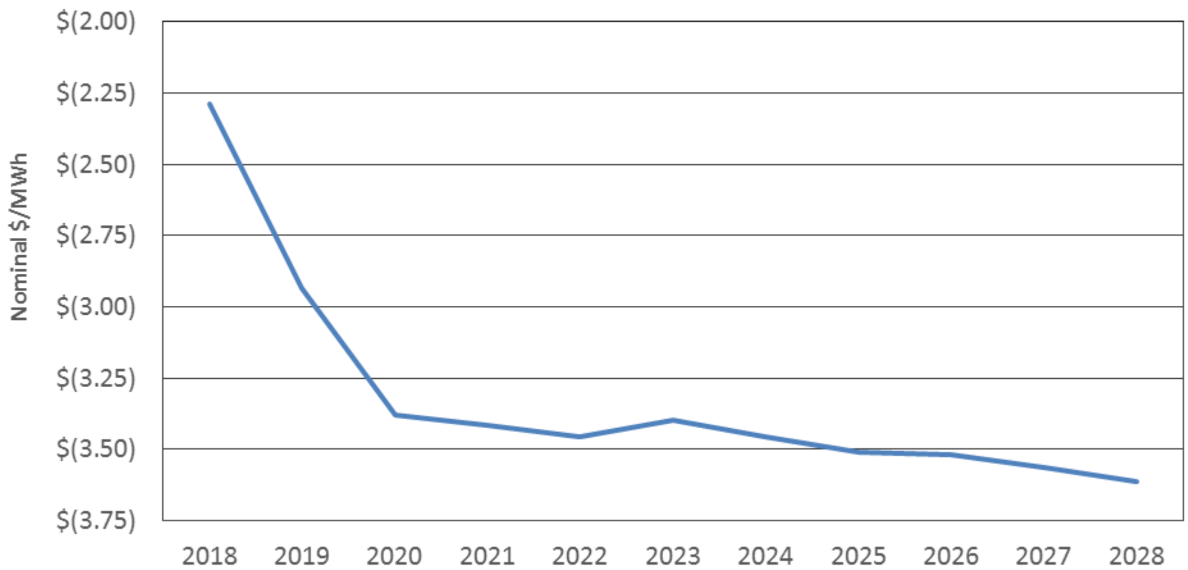


Source: ICF International, SNL

Electric Price Impact (excluding volatility)

Access Northeast is designed to provide firm gas supply to the gas fired power plants that are connected to the Spectra pipelines. The Spectra pipelines are already directly and indirectly connected to 70 percent of the gas fired generation plants that serve New England. Further, Spectra pipelines serve twice the number of efficient gas fired power plants than the other pipelines combined. Because Access Northeast along with interconnecting pipelines and regional storage assets will provide firm service to gas fired generators (even during severe winter conditions), the reduction in natural gas prices resulting from Access Northeast will result in a reduction of electricity prices. Exhibit 19 shows the energy price with Access Northeast minus the energy price without Access Northeast. Access Northeast reduces the New England annual average wholesale power price by $2.25/MWh to $3.50/MWh between 2019 and 2028, with substantial reduction as high as $15/MWh during peak winter periods.

Exhibit 19: New England Annual Average Electric Price Reductions with Access Northeast (excluding volatiity impact)



Source: ICF International

Consumer Cost Savings

ICF estimates the potential cost savings to New England's electric consumers from reductions in average price levels and in natural gas and electric price volatility.

Cost Savings to Electric Consumers from Average Price Reduction

Analysis results presented above show that Access Northeast may reduce New England's wholesale energy price by lowering the regional natural gas price and the fuel costs for gas fired power generation. ICF assumes that for this analysis that reductions in wholesale electricity prices provided by infrastructure solutions benefit all New England electric consumers. Annual cost savings to electric consumers are calculated as the reduction in New England's wholesale energy prices multiplied by ISO-NE annual net energy load.

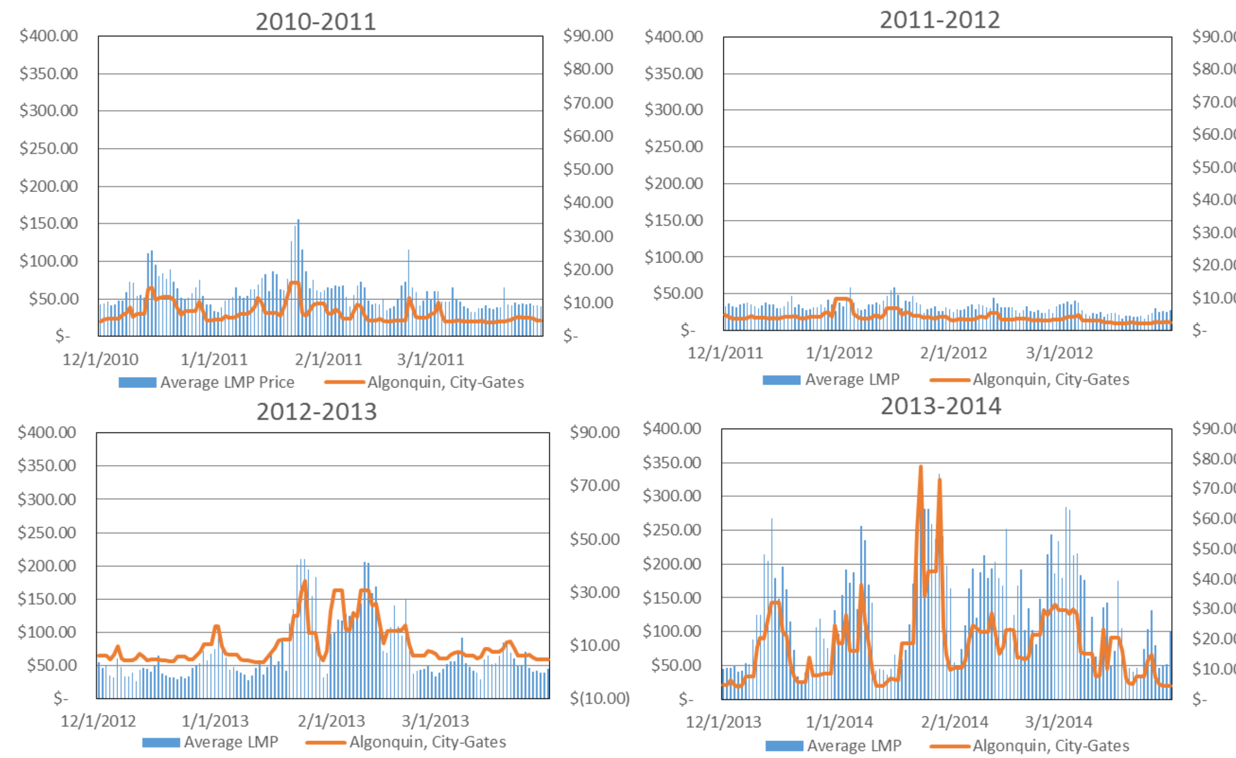
Benefits from Reduced Daily Gas Price Volatility

In addition to the overall price decreases that ICF derived using the GMM and IPM models, there are additional cost savings to natural gas and electric consumers due to reductions in daily natural gas and power price volatility.

For the purpose of this analysis, ICF assumes that Access Northeast will introduce 500 MMcf/d incremental gas supply capacity into New England year-round, and an additional 6 Bcf of winter supply (400 MMcf/d of send out from the LNG storage). Both serve to relieve the winter constraints recently experienced in New England. In addition to reducing monthly average prices captured by ICF's GMM modeling analysis, the volatility of prices, i.e., the frequency and magnitude of price spikes, may be reduced. As New England's power generators dispatch their gas generation based on daily fuel prices, reduction in natural gas price volatility may result in further reduction in natural gas prices.

For this study, ICF uses the frequency and magnitude of extraordinary price spikes as a proxy to measure the impact of volatility reductions. Exhibit 20 presents daily ALQ price and ISO-NE daily LMPs for the past four winters.

Exhibit 20: New England Power and Gas Price Correlation



Source: ICF International, SNL, ISO-NE

ICF estimates a range of the volatility reduction impacts by assuming two volatility reduction levels:

- Low Volatility Reduction Assumption - Frequency and size of price spikes were reduced by half from a moderate volatility market, similar to that experienced in the 2010-2011 or 2012-2013 winter;

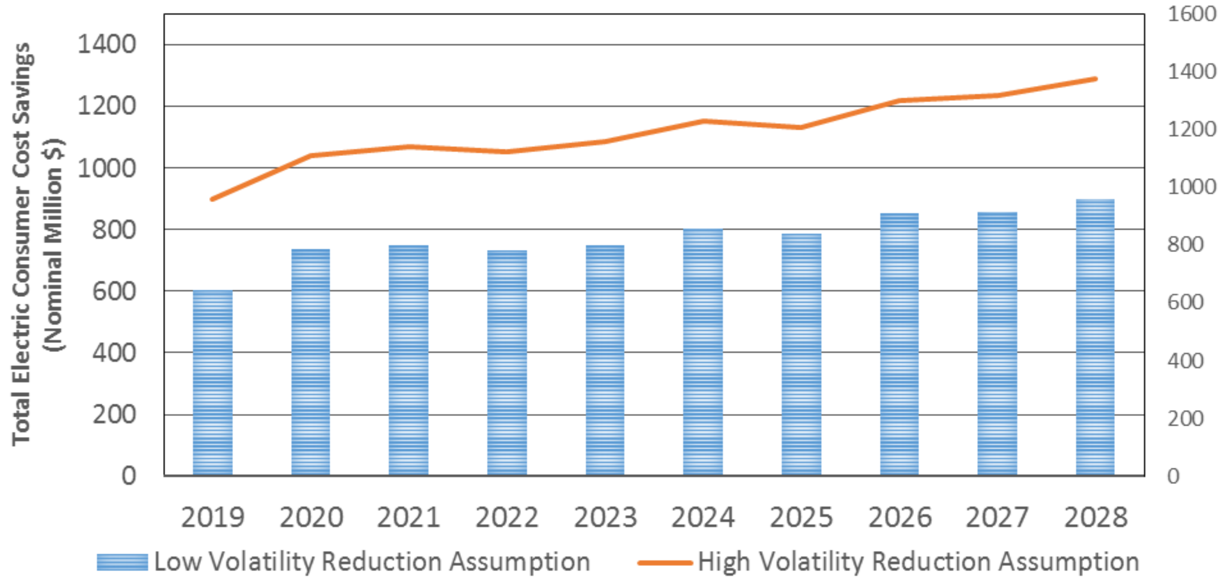
- High Volatility Reduction Assumption - Frequency and size of price spikes were reduced by half from a high volatility market, similar to that experienced in the 2013-2014 winter.

Both assumptions reflect a conservative scenario that a project like Access Northeast will result in "reduction" and not "elimination" of volatility. ICF estimates that additional eight percent reduction in natural gas prices for December and March using the low volatility assumption and 20 percent further price reduction using the high volatility assumption, which translate into an additional $330 million and $750 million a year of cost savings to electric consumers.

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, Exhibit 21 shows that a project like Access Northeast could generate $600 million to $1.4 billion a year to New England electric consumers. The annual average cost savings to consumers for the 10-year period is $780 million to $1.2 billion for the low and high volatility assumption scenarios, respectively.

Exhibit 21: New England Electric Consumer Cost Savings



Source: ICF International

Cost Savings - Cold Weather and Nuclear Outage Scenario

ICF assessed the impact of Access Northeast by assuming that the winter of 2018-2019 is a "1-in-20 year design" winter and also experiences a large nuclear outage event. On the electric market, ICF also used the 90-10[31] scenario from ISO-NE's CELT report that has a significantly different peak energy load profile than under the normal weather conditions.

Weather and RCI Demand Assumptions

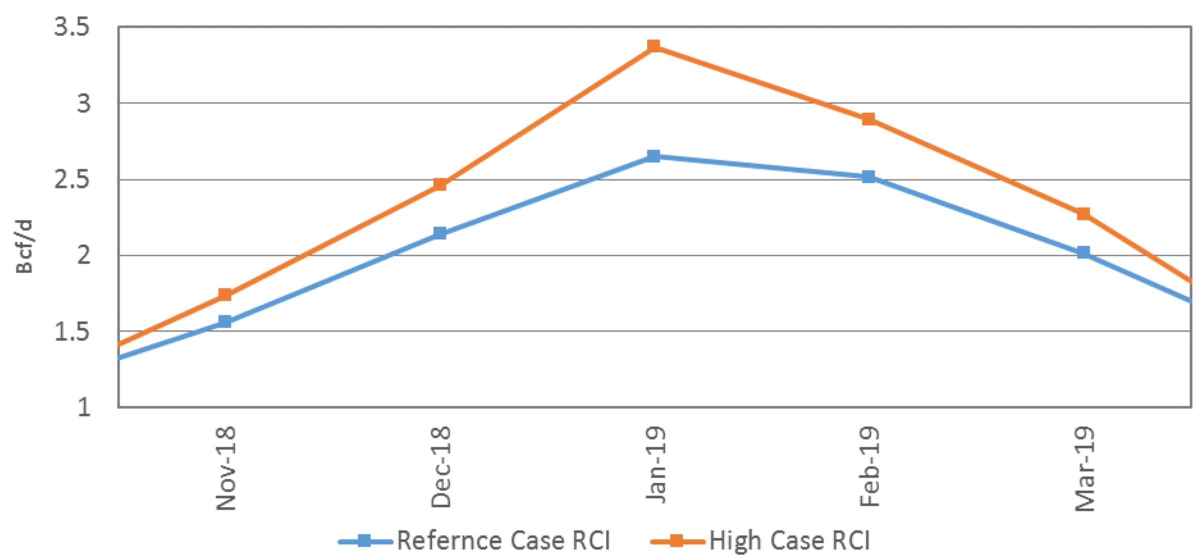
ICF utilized the design winter weather data provided by Eversource, to calibrate the design winter conditions in New England. Exhibit 22 shows that the design winter is, on average, 20 percent colder than normal winter conditions. Exhibit 23 shows that residential and commercial demand for the five winter months is 20 percent higher than under normal weather conditions.

Exhibit 22: 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 International

Exhibit 23: RCI Demand Comparison - High Winter Case vs. Reference Winter Case



Source: ICF International

[31] 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 market. Exhibit 24 shows that on average (before taking volatility into consideration), natural gas price could be reduced by 23 percent and electric prices be reduced by 12 percent.

Exhibit 24: Colder than Normal Winter Scenario Power and Gas Price Results with and without Access Northeast (Excluding Volatility Impact)

	Natural Gas Prices ($/MMBtu)			Power Prices ($/MWh)		
	With Access Northeast	Without Access Northeast	Delta	With Access Northeast	Without Access Northeast	Delta
Nov-18	$4.95	$ 5.45	10%	$40.80	$43.57	7%
Dec-18	$10.83	$12.79	18%	$52.31	$56.96	9%
Jan-19	$20.95	$ 31.73	51%	$81.19	$98.65	22%
Feb-19	$12.07	$14.87	23%	$60.99	$68.93	13%
Mar-19	$6.44	$7.38	15%	$53.67	$58.05	8%

Source: ICF International

Under the cold weather and nuclear outage scenario, ICF assumes that Access Northeast could reduce the volatility by a level consistent with the high volatility reduction assumption. In total, Access Northeast could generate approximately $1.1 billion cost savings to electric consumers in the five winter month period, 25 percent higher than under normal winter conditions. The average cost savings of the ten-year period, if assuming the 1-in-20 weather scenario and high volatility reduction, is approximately $1.4 billion a year.

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 $2.4 billion. Assuming this translates into a $400 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.

Exhibit 25: Annual Access Northeast Cost and Benefits Summary

	Total Benefits	Net Benefits
Base Case Normal Weather	$0.8 - $1.2 billion	$0.4 - $0.8 billion
1-in-20 Weather	$1.4 billion	$1.0 billion
2013/2014 Extreme Winter	$2.5 billion	$2.1 billion

Source: ICF International

The net benefits to New England, ranging from $0.4 billion to $2.1 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 $2.4 billion investment required for the project could be recovered from the cost savings in a single extreme winter similar to 2013/14.

Passion. **Expertise. Results.**

Division 1-14

Request:

Regarding page 62 of 63 of the Janzen testimony where offsetting hedge transactions are discussed, how many days does the Company think it takes for a NPP to consummate the offsetting transactions?

Response:

To clarify, the offsetting transactions described on page 62 of 63 of the Direct Testimony of Margaret M. Janzen referred to the actions of wholesale SOS suppliers, not NPPs.

The Company does not have specific knowledge of wholesale SOS suppliers' offsetting transactions to hedge their winning bid prices. After winning a FRS contract, the SOS suppliers most likely will attempt to hedge their positions as soon as possible to minimize their risk.

Prepared by or under the supervision of: Margaret M. Janzen