REDACTED

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 16-___

PETITION FOR APPROVAL OF A LONG-TERM CONTRACT
FOR NATURAL GAS INTERSTATE PIPELINE CAPACITY

DIRECT TESTIMONY OF JAMES M. STEPHENS

February 18, 2016

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I. Introduction

Q. Please state your name, position, and business address.

A. My name is James M. Stephens. I am a Partner of Sussex Economic Advisors, LLC ("Sussex"). My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts, 01581.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this direct testimony to the New Hampshire Public Utility Commission (the "Commission") on behalf of Public Service Company of New Hampshire ("PSNH") d/b/a Eversource Energy (hereinafter, "Eversource" or the "Company").

Q. Please describe your educational background.

A. I hold a Bachelor of Science degree in Management and a Master of Business Administration with a concentration in Operations Management from Bentley College.

Q. Please describe your professional experience in the energy and utility industries.

A. I have over 25 years of experience in the energy industry and have held senior management positions at consulting firms, energy marketing companies and natural gas local distribution companies ("LDCs"). In my role as a consultant, I have assisted numerous clients with regulatory policy strategy/tactics and energy market analyses/assessments including: the analysis of regional energy market dynamics and the associated drivers for new natural gas infrastructure; the evaluation of new markets/opportunities; market entry/exit strategies; market implications of new energy infrastructure; integrated resource plans; natural gas supply portfolio evaluation and optimization; and management prudence. In addition, I have served as the President of a retail energy marketing firm where I was responsible for all aspects of business unit management including front, mid, and back-office functions. I was also responsible for Gas Supply Procurement and Portfolio Optimization for Colonial Gas Company, which is now a subsidiary of National Grid. A summary of my professional and educational background is provided with my testimony as Attachment EVER-JMS-1.

Q. Have you previously provided testimony before the Commission?

A. No, I have not previously appeared before the Commission.

Q. Have you submitted expert testimony in other jurisdictions?

A. Yes, I have submitted expert testimony in several other jurisdictions including before the Federal Energy Regulatory Commission ("FERC"), the States of Massachusetts and Maine, and the Canadian Provinces of Ontario and Québec. A list of past cases in which I have submitted expert testimony is provided with my testimony as Attachment EVER-JMS-2.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the market factors that are influencing Eversource's decision to acquire firm natural gas transportation and storage capacity for release to New England power generators on a priority basis. My review includes a discussion of the regional natural gas supply and demand trends affecting the value of transportation capacity during certain periods of high demand, and how those trends ultimately influence the price of wholesale and retail electricity prices. Further, my testimony reviews the competitive solicitation process undertaken by the Eversource Energy electric distribution companies (the "Eversource EDCs"), in conjunction with

National Grid, to address these market trends. Next, I review the qualitative and quantitative analysis developed by Sussex to compare the various proposals received in response to the competitive solicitation process conducted by the Eversource EDCs and National Grid. Lastly, my direct testimony reviews the proposed long-term contracts between the Company and Algonquin Gas Transmission LLC ("Algonquin" or "AGT") for firm natural gas transportation and storage capacity on the Access Northeast project (together the "ANE Contract").

Q. Please summarize your conclusions related to the Company's execution of the ANE Contract with Algonquin.

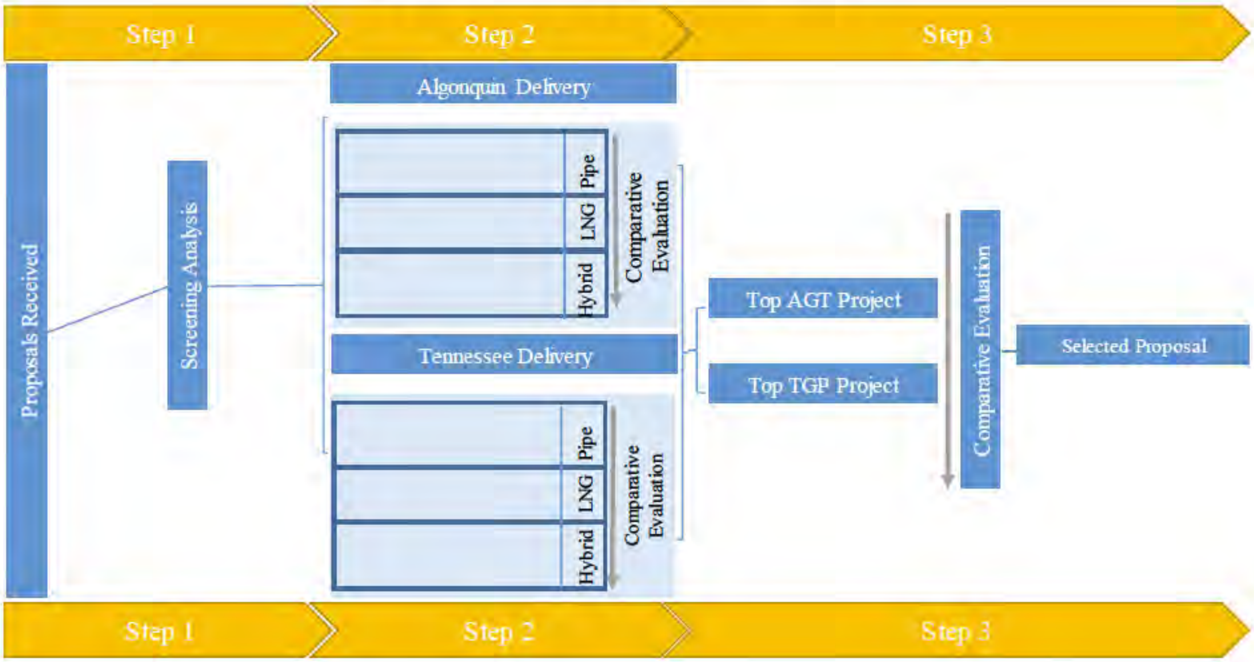
A. The ANE Contract will facilitate the development of the Access Northeast project, which is a reasonable and viable solution to enhance gas supply deliverability and to address the high wholesale natural gas and power prices recently experienced in New England. Access Northeast is expected to provide 500,000 MMBtu/day of incremental natural gas transportation capacity into New England and an even greater volume (i.e., 900,000 MMBtu/day) of natural gas deliverability during the peak winter and summer months. As discussed by Company Witness James G. Daly, the liquefied natural gas ("LNG") storage component of the Access Northeast project will provide flexibility to meet "fast start" requirements for power generators. By assigning this firm capacity on a priority basis to New England power generators, Eversource anticipates that the Access Northeast project will result in increased natural gas supply and reduced wholesale natural gas and power prices, which will offset the cost of the contracts for electric retail customers.

As part of the decision-making process used to select the Access Northeast project, a competitive solicitation process was conducted by the Eversource EDCs, in conjunction with National Grid. The competitive solicitation process produced 20 resource alternatives from seven entities including owners and operators of major infrastructure assets in New England and Maritime Canada.[1] Specifically, the following entities provided responses: Algonquin, Tennessee Gas Pipeline, L.L.C. ("Tennessee" or "TGP"), Portland Natural Gas Transmission System ("PNGTS"), GDF SUEZ Gas NA LLC ("GDF SUEZ"), Repsol Energy North America Corporation ("Repsol"), Iroquois Gas Transmission System, L.P. ("Iroquois"), and Stolt LNGaz Inc. ("Stolt"). The options submitted by the bidders ranged from the construction of incremental pipeline capacity to contracts for imported LNG to a combination of constructing incremental pipeline capacity and market area LNG storage.

To evaluate the proposals received by the Eversource EDCs, Sussex relied on a three-step evaluation process as shown in Figure 1 below.

[1] Please note that several of the bidders submitted proposals with multiple options.

Figure 1: Sussex Evaluation Process



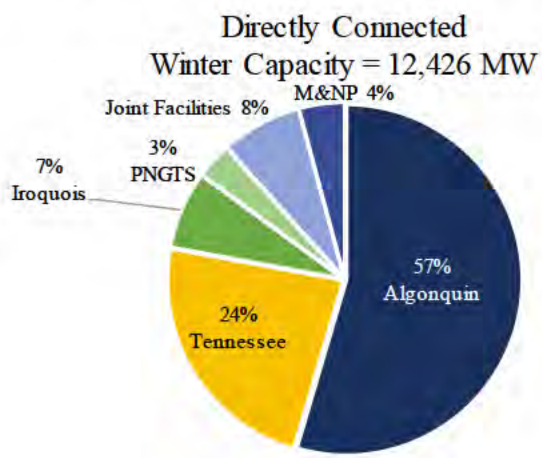
Step 1 of the evaluation process encompassed a screening analysis of each proposal, resulting in the elimination of two of the proposals due to insufficient volumes and the lack of a specified cap on cost-of-service based rates. Therefore, five supply and/or transportation proposals were included in the next phase of the evaluation process. To the extent that a proposal included multiple options, Sussex evaluated each option that was consistent with the screening criteria.

In Step 2 of the evaluation process, the Sussex analysis focused on the capability of the proposed projects to directly serve power generation load on Algonquin and Tennessee.

Figure 2 shows that Algonquin serves approximately 57 percent of the natural gas-fired and dual-fuel generating capacity directly connected to an interstate pipeline in New

England, while Tennessee serves approximately 24 percent of the directly connected natural gas and dual-fuel generation.[2]

Figure 2: N.E. Gas-Fired Generation Directly Connected to Interstate Pipelines[3]



Given that most New England generation is located within the Algonquin or Tennessee delivery areas, Sussex focused its quantitative analysis on the estimated cost to deliver natural gas supplies to the Algonquin and Tennessee delivery areas. Sussex also conducted a qualitative assessment of each proposal and proponent using certain metrics and risks, including: (i) project development experience; (ii) rate structure or regulation; (iii) access to gas supply; and (iv) liquidity of pricing location.

Based on the analysis developed in Step 2, the Access Northeast project and the

[2] As proposed, the Access Northeast project would serve the natural gas-fired and dual-fuel generation on Maritimes and Northeast Pipeline ("M&NP") and the Joint Facilities (i.e., the 101-mile pipeline from Westbrook, ME to Dracut, MA that is jointly owned by M&NP and PNGTS) raising the market share served by the Access Northeast project from 57 percent to nearly 70 percent.

[3] Based on Sussex analysis of publicly available information. Sources: U.S. EIA, Form EIA-860 Detailed Data for 2014, release date October 21, 2015; ISO New England, CELT Report: 2015-2024 Forecast Report of Capacity, Energy, Loads, and Transmission, May 1, 2015; and Levitan & Associates, Inc., Gas-Electric System Interface Study: Existing Natural Gas-Electric System Interfaces, Appendix 4, April 4, 2014. The percentages do not sum to 100 percent because Ocean State Power I/II can be served by either Algonquin or Tennessee.

Tennessee Northeast Energy Direct ("NED") project were identified as the most cost-effective proposals to deliver natural gas to power generators connected to the Algonquin and Tennessee pipelines, respectively. The Access Northeast project and the Tennessee NED project were then compared to one another in Step 3. Sussex identified the Access Northeast project as the option with the highest capability to impact reliability and pricing issues affecting the New England region. As shown in Table 1, the Access Northeast project provides cost-effective natural gas deliverability and received a higher qualitative evaluation, when compared to the Tennessee NED project without LNG and TGP Z4 receipts.

Table 1: Access Northeast and Tennessee NED Projects Comparative Evaluation[4]

Project Name	Landed Cost Rank	
	Annual 2016/2017-2021/2022 Forwards	Winter 2016/2017-2021/2022 Forwards
Access Northeast	[redacted]	[redacted]
NED Ex-LNG TGP Z4 Receipts	[redacted]	[redacted]

Project Name	Relative Qualitative Evaluation							
	Winter Generating Capacity Served	Peak Day Deliverability	Fixed Demand Charges	Flexibility	Receipt Point Liquidity	Construction Risks	Sponsor Financial Condition	Capacity Mitigation Opporunities
Access Northeast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NED Ex-LNG TGP Z4 Receipts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

As shown in Table 1 above, the Access Northeast project will serve the greatest proportion of directly connected generation and provide the greatest volume of peak day

4 Check marks are indicative of the entity with a higher assessment in each category based on the analysis and information contained herein. The lack of a check does not indicate the lack of qualification in the category, merely that the other entity was assessed higher. In instances where both the Access Northeast and Tennessee NED projects received check-marks, the projects were assessed to be comparable.

deliverability. Similarly, the Access Northeast project will provide access to liquid pricing points and will make use of existing right-of-ways to mitigate development risk.

Algonquin, as the developer of the Access Northeast project, has substantial experience constructing, operating, and expanding natural gas transportation in the New England region. Algonquin's experience includes the currently under construction Algonquin Incremental Market ("AIM") project to expand Algonquin, and the proposed Atlantic Bridge project to expand Algonquin and M&NP using similar construction methods as are proposed for the Access Northeast project. Algonquin and its owners have substantial financial capability, including investment grade credit ratings, to fund and complete the project. The current financial condition of Algonquin's parent companies was assessed to be stronger than the competing proposal.

Importantly, the Access Northeast project will provide incremental access to natural gas supplies from the Marcellus and Utica shale basins. Both basins have shown remarkable growth in recent years and are currently projected to continue to grow during the term of the proposed ANE Contract. By providing access to these stable, low-cost natural gas supplies at a reasonable cost for the delivery infrastructure, Eversource is addressing the pipeline constraints driving increasing wholesale power prices.[5]

Lastly, it is critical to understand that committing to the Access Northeast project at this

[5] As noted in the testimony of Company Witness Mr. James G. Daly, the additional costs to New England electricity customers were more than $3 billion during the 2013/2014 winter, as compared to prior winters. ICF has determined that the Access Northeast project will save customers $1.4 to $1.9 billion each year and as much as $3.1 billion in a design winter. Taking into account the cost of the pipeline, the net benefits to New England electric consumers could range from $0.9 to $1.3 billion per year on average, under normal weather conditions.

point in time will not preclude other options in the future. As discussed in the Company's testimony, Eversource remains committed to pursuing its energy efficiency programs and renewable energy additions to the resource portfolio.

Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is organized as follows:

- Section II – Regulatory Context and Guidelines – In this section, I review the regulatory guidelines and principals that have been expressed by the Commission in its recent decision in Order No. 25,860, in Docket No. IR 15-124 Investigation into Potential Approaches to Ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire ("Order No. 25,860") regarding the approval of firm natural gas transportation agreements entered into by the New Hampshire electric distribution companies ("EDCs"). In addition, I review certain requirements for seeking approval of a natural gas pipeline from the FERC, including the commercial practicalities of pipeline construction.

- Section III – Market Context – In this section, I review the market dynamics that are currently shaping the New England natural gas and power markets, including changes in natural gas demand and supply.

- Section IV – Competitive Solicitation Process – This section reviews the competitive procurement process utilized by the Eversource EDCs and National Grid to solicit interest for firm natural gas supply and delivery services.

- Section V – Evaluation of the Proposals – This section reviews the evaluation process utilized by Sussex to evaluate the proposals received in response to the competitive solicitation conducted by the Eversource EDCs and National Grid.
- Section VI – Overview of the Proposed ANE Contract – Section VI reviews the ANE Contract executed by Eversource and Algonquin for natural gas transportation and storage capacity on the Access Northeast project.
- Section VII – Summary and Conclusions – This section summarizes the Sussex evaluation and conclusions related to the ANE Contract.

Q. Please list the attachments to your direct testimony.

A. In addition to my testimony, I am sponsoring the following eight attachments:

- Attachment EVER-JMS–1 – contains the curriculum vitae of James M. Stephens.
- Attachment EVER-JMS–2 – contains the testimony listing of James M. Stephens.
- Attachment EVER-JMS–3 – contains a summary of the pipeline project sponsors and LNG suppliers to whom the RFP issued by the Eversource EDCs and National Grid RFP was addressed.
- Attachment EVER-JMS–4 – contains a detailed summary of the Sussex landed cost analysis.
- Attachment EVER-JMS–5 – contains the Sussex qualitative review of the Pipeline proposals.
- Attachment EVER-JMS–6 – contains the Sussex qualitative review of the

imported LNG proposals.

- Attachment EVER-JMS–7 – contains the Sussex qualitative review of the Hybrid proposals.
- Attachment EVER-JMS–8 – contains a summary of a comparative evaluation of the Access Northeast project and the Tennessee NED project.

II. Regulatory Context and Guidelines

Q. Are there challenges in the New England wholesale power market that are not currently addressed by the New Hampshire EDCs or another market participant?

A. Yes. The Commission noted the New England market challenges in comments to the FERC by stating the following:

> "…the problem of fuel assurance has been particularly acute in New England in recent years, resulting in system reliability concerns on the coldest winter days when the region's pipeline capacity is constrained, paired with record high wholesale electricity prices of the past two winters and extreme price volatility." [6]

As described in the testimony of Company Witness James G. Daly, the existing Independent System Operator New England ("ISO New England" or "ISO-NE") rules do not require market participants to procure firm fuel supplies to offer energy into the wholesale power market.[7] As a result, many natural gas-fired generators rely on interruptible transportation services to deliver the necessary natural gas to fuel their generators.[8] The lack of firm transportation capacity contracts has led to high demand and resultant high prices for pipeline transportation services during the winter demand

[6] FERC Docket Nos. AD13-7-000, AD14-8-000, Comments of the New Hampshire Public Utilities Commission, at 3.
[7] Company Witness Mr. James G. Daly also discusses the steps ISO-NE has taken to mitigate this concern.
[8] ISO-NE, 2015 Regional System Plan, November 5, 2015, at 131.

months.[9] The impact of this lack of firm natural gas transportation capacity on electricity prices and emissions was recognized by the Commission in its comments before the FERC which stated the following:

> "Without market reforms that encourage the use of firm natural gas supplies by generators, as natural gas prices spike in the winter months, fuel oil and LNG will increasingly become the fuels of choice for electricity production and wholesale and retail electricity prices will remain at elevated levels. In addition, because fuel oil has a significantly dirtier emissions than natural gas, its increased use risk reversing progress on reducing power plant emissions profile in New England, an outcome that may make the permitting of back-up fuel oil facilities difficult if not impossible."[10]

Finally, the Commission has noted that this challenge "can be addressed economically only through the addition of new pipeline capacity."[11]

Q. Please explain how the lack of sufficient incentive for generators to execute firm transportation contracts affects the development of natural gas pipelines in New England.

A. New pipeline development requires the investment of hundreds of millions or billions of dollars into a fixed asset with limited or no alternative uses. The sponsors of new pipeline projects must demonstrate to lenders and investors that they will be able to recoup their investment with reasonable certainty and within a reasonable period to obtain the financing required for new projects. Absent the ability to demonstrate the requisite demand, investors are unwilling to provide the funds required to complete the project. Thus, the projects are generally not able to be financed.

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[9] Ibid.
[10] FERC Docket Nos. AD13-7-000, AD14-8-000, Comments of the New Hampshire Public Utilities Commission, at 5-6.
[11] Ibid., at 7.

As a result, sponsors of new pipeline projects require prospective shippers to execute precedent agreements to ensure adequate demand exists to support the pipeline and provide for recovery of the investment. The precedent agreements provide for, among other items, execution of a firm transportation agreement once certain conditions precedent are met by both parties to the agreement. The conditions precedent often include receipt of all required regulatory approvals and construction of the pipeline in a manner that is consistent with the initial development plans.

When users, such as electric generators, elect not to sign up for firm transportation capacity either on existing pipelines or new pipeline developments, it signals to investors and project sponsors that the risk assumed by the project sponsor is significant, and the project sponsor may be unable to recover its investments and earn an adequate return within a reasonable period. Thus, projects are not generally built to accommodate the fuel demands of those customers, including power generators.

In addition, to obtain FERC approval of an application for a Certificate of Public Convenience and Necessity ("CPCN") a pipeline must demonstrate the need for the incremental capacity, which is generally shown by submitting executed precedent agreements from firm shippers.

Q How do natural gas transportation customers, such as power generators, anticipate sourcing natural gas absent firm transportation agreements?

A. Customers that do not have firm transportation capacity generally expect to use interruptible capacity or acquire capacity released by holders of firm transportation capacity.[12] However, and as noted in Section III below, in times of high demand, the present holders of that firm transportation require the capacity to serve firm loads and meet contractual commitments; thus limiting the capacity released or available on an interruptible basis.

Q. Has the Commission indicated that it would consider approval of natural gas transportation contracts entered into by the New Hampshire EDCs for purposes of addressing the pipeline constraints?

A. Yes, in Order No. 25,860, the Commission indicated it would consider an EDC petition for approval of a natural gas transportation capacity contract using a two phase review process. The first phase to review the legality of approving such a contract, and a second phase to review the merits of the natural gas transportation capacity contract. Specifically, the Commission stated the following:

> "Such a proceeding would be opened if and when a New Hampshire EDC files a petition for a proposed capacity acquisition, and related cost recovery. The Commission would consider the petition in separate phases. In the first phase, the Commission would review briefs submitted by the petitioner EDC, Staff, and other parties regarding whether such capacity procurement is allowed under New Hampshire law…If the Commission were to rule in the affirmative regarding the question of legality, it would then open a second phase of the proceeding to examine the appropriate economic, engineering, environmental, cost recovery and other factors presented by the actual proposal."[13]

In addition, Order No. 25,860 notes that unlike New Hampshire LDCs that have appropriate criteria for planning and completing natural gas transportation capacity procurements, the New Hampshire EDCs lack any such planning and evaluation criteria.

[12] ISO-NE, 2015 Regional System Plan, November 5, 2015, at 131.
[13] Order No. 25,860, at 3.

The Commission noted its strong preference for the use of an "open, transparent, and competitive" procurement process when reviewing a potential EDC petition for approval of a natural gas transportation capacity contract.[14] The Commission has otherwise not expressed a specific evaluation framework for such contracts. Nonetheless, it is clear the Commission and Commission Staff expect such a procurement to provide benefits to customers including meaningfully reducing wholesale and retail electricity prices.

III. Market Context

A. Natural Gas Demand

Q. Has the demand for natural gas in New England increased since 2001?

A. Yes. The annual natural gas demand in New England has increased by approximately 17 percent, from approximately 770 Bcf[15] in the 2001/2002 split-year[16] to 900 Bcf in the most recent 12-month period ending August 2015.[17] Figure 3, below, depicts this trend and reflects seasonal fluctuation (winter peaking) in New England natural gas demand.

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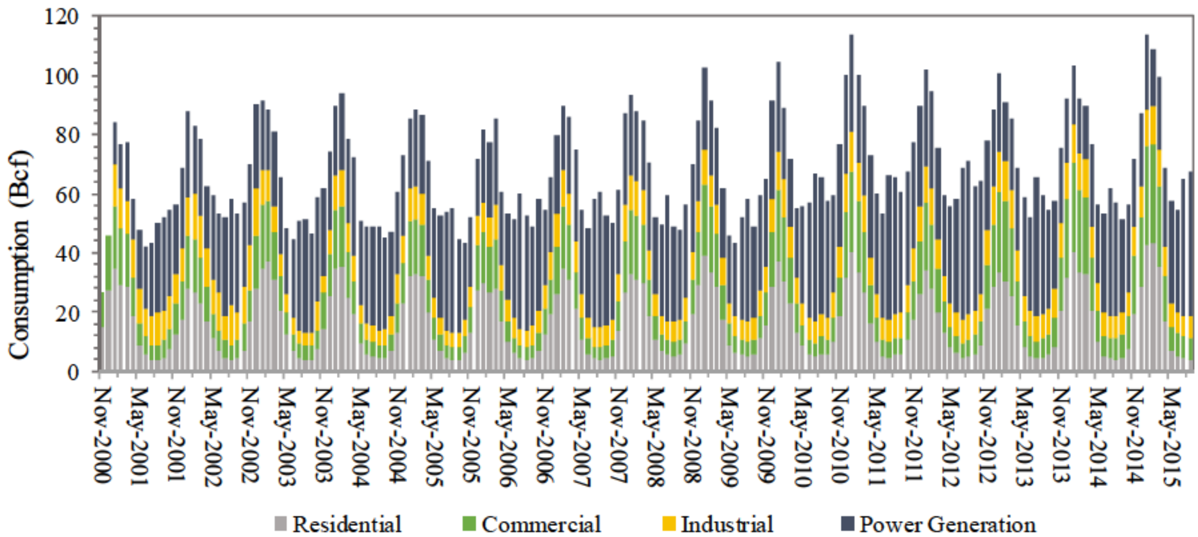
14 Ibid., at 4.

15 For purposes of my direct testimony and analyses, I have assumed that 1 Mcf = 1 Dth = 1 MMBtu.

16 Throughout my direct testimony, the winter period is defined as the five-month period from November to March, the summer is the seven-month period from April to October, and a split-year is the twelve-month period from November to October.

17 Data for certain months in 2015 are based on estimates. Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont and Maine, release date October 30, 2015.

Figure 3: Historical Monthly Natural Gas Demand (November 2000 – August 2015)[18]



The New England natural gas demand in the winter season has grown by a compound annual growth rate ("CAGR") of approximately 1.8 percent over the 2001/2002 to 2014/2015 split-years.[19] That demand growth is being driven primarily by growth in the power generation sector where natural gas-fired generation is consistently displacing alternative generation and replacing older generating capacity fueled by coal, oil and nuclear.[20]

Q. Please discuss the New England natural gas demand by sector.

A. In New England, the power generation segment is the largest consumer of natural gas and presently represents approximately 41 percent of the total annual natural gas demand.

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18 Ibid.

19 Ibid.

20 An example of this trend is the Salem Harbor plant, an oil-fired plant that was retired and is being replaced with a modern, combined cycle power plant fueled by natural gas.

The residential and commercial segments, combined, account for 46 percent, and the industrial segment accounts for 13 percent of the total annual demand.[21]

Q. Is the demand for natural gas in New England expected to continue increasing from its current level?

A. Yes. The demand for natural gas in New England is expected to continue to grow. The U.S. Energy Information Administration ("EIA") is forecasting the annual demand for natural gas in New England to increase from approximately 900 Bcf in 2015 to approximately 1,052 Bcf in 2035, or approximately 17 percent in aggregate. A primary driver of the demand growth is the power generation segment, which is forecasted to grow by 26 percent between 2015 and 2035.[22]

Q. Please discuss the existing power generation fleet in New England.

A. There are approximately 350 generators in the ISO-NE region, with a total generating capacity of approximately 31,000 MW in the summer and 33,000 MW in the winter.[23]

Q. Is natural gas the primary fuel for power generation in New England?

A. Yes. Natural gas and dual-fuel (i.e., natural gas/oil) generating units currently account for nearly 60 percent of the total generating capacity in ISO-NE and approximately 46 percent of the total electricity generated in ISO-NE.[24] Between 2001 and 2015, the

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[21] Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont and Maine, release date October 30, 2015.

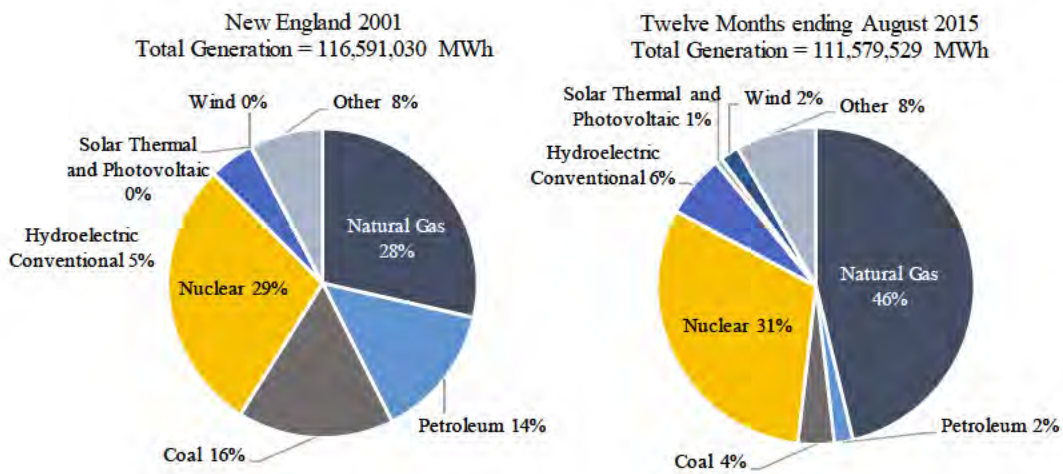
[22] Data for certain months in 2015 are based on estimates. Sources: U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont and Maine, release date October 30, 2015; and U.S. Energy Information Administration, Annual Energy Outlook 2015, release date April 14, 2015.

[23] See also, ISO New England, Seasonal Claimed Capacity Monthly Report, November 3, 2015.

[24] Sources: ISO New England, Seasonal Claimed Capacity Monthly Report, November 3, 2015; and U.S. Energy Information Administration, Monthly Generation Data by State, Producer Sector and Energy Source; 2001-2015 EIA-923 Form.

amount of electricity generated by natural gas-fired units increased from approximately 33.3 TWh in 2001 to approximately 51.6 TWh in 2015, or an increase of 55 percent. Over that same period, electricity generated by coal- and oil-fired units decreased from 16 percent and 14 percent, respectively, of the total electricity generation in 2001 to approximately 4 percent and 2 percent, respectively, of total electricity generation in the 12-month period ending August 2015 (Figure 4, below).

Figure 4: Historical Annual Generation by Fuel Type[25]



Q. Will natural gas continue to be the primary fuel for power generation in New England?

A. Yes. In a 2012 study, ISO-NE identified approximately 8,300 MW of oil- and coal-fired generating units that were "at-risk" of retirement by 2020.[26] A subset of the 8,300 MWs identified by ISO-NE as "at-risk" is shown in Figure 5 and Table 2 which note that five

25 Source: U.S. Energy Information Administration, Monthly Generation Data by State, Producer Sector and Energy Source; 2001-2015 EIA-923 Form.

26 See, ISO New England, Generation Retirements Study, December 2012.

of the generating units that were identified as "at-risk" by ISO-NE have already retired or have announced plans to retire by a date certain. In addition, two nuclear units that were not included in the 8,300 MWs identified as 'at-risk' by ISO-NE have already retired or will retire by June 2019. Collectively, these two nuclear units represent 1,287 MWs of baseload capacity.

Figure 5: Power Generation Retirements[27]

[27] Source: ISO New England, Key Facts: Resource Mix [modified by Sussex].

Table 2: Power Generation Retirements[28]

Plant Name	Fuel Type(s)	ISO-NE Load Zone	Scheduled Retirement Date	Capacity (MW)
Salem Harbor	Coal; Oil	NEMA/Boston	Retired (June 2014)	749
Mount Tom	Coal	WCMA	Retired (Late 2014)	143
Vermont Yankee	Nuclear	VT	Retired (Late 2014)	604
Brayton Point	Coal; Oil	SEMA	June 2017	1,535
Bridgeport Harbor	Coal	CT	June 2017	180
Norwalk Harbor	Oil	CT	June 2017	342
Pilgrim	Nuclear	SEMA	June 2019	683
TOTAL				**4,236**

As shown above, nearly 4,236 MWs or 15 percent of the region's existing winter generating capacity has ceased operations (1,496 MW) or will retire by 2019 (2,740 MW). To the extent that this capacity is replaced, it is highly likely that it will be replaced by new natural gas-fired generating units, thus further increasing natural gas demand.

Q. Please further discuss why the amount of natural gas-fired capacity is likely to increase.

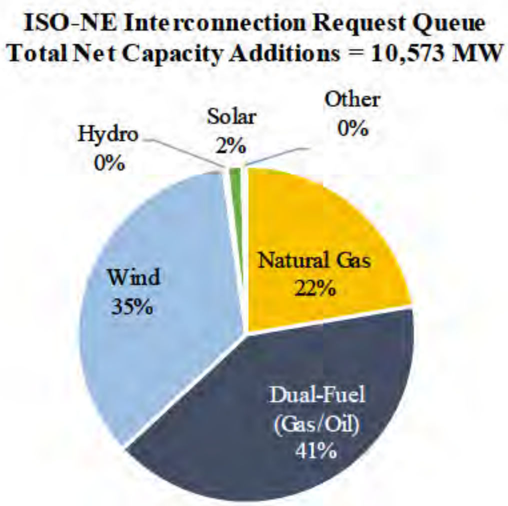
A. The ISO-NE interconnection queue contains 92 proposed generation projects, representing approximately 10,600 MW of incremental capacity.[29] As illustrated in Figure 6 below, the majority (i.e., approximately 63 percent) of the proposed generation projects are fueled by natural gas or are dual-fuel (i.e., natural gas/oil).[30]

[28] Sources: ISO New England, Key Facts: Resource Mix; ISO New England, Seasonal Claimed Capacity Monthly Report, November 3, 2015; and ISO New England, Status of Non-Price Retirement Requests, October 13, 2015.

[29] Source: ISO New England, Interconnection Requests for New England Control Area, November 1, 2015.

[30] Wind projects account for most of the remaining capacity (i.e., 35 percent).

Figure 6: Proposed Power Generation Projects[31]



Fuel Type	Number of Projects	Net MW
Natural Gas	18	2,359
Dual-Fuel (Gas/Oil)	21	4,314
Wind	39	3,670
Hydro	7	33
Solar	5	158
Other	2	38
Total	92	10,573

*Excludes transmission projects

Of the 39 proposed natural gas and dual-fuel (i.e., natural gas/oil) generation projects, the largest net capacity additions are located in Massachusetts, Connecticut, and Rhode Island (i.e., along the existing Algonquin and Tennessee pipelines). Specifically, 50 percent of the net capacity additions (i.e., 3,328 MW) are located in Massachusetts; followed by net capacity additions of 1,794 MW in Connecticut and 1,452 MW in Rhode Island. Please see Table 3 below.

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31 Ibid.

Table 3: Proposed Natural Gas and Dual-Fuel Power Generation[32]

ISO-NE Zone	Number of Projects	Net MW by Fuel Type(s)			Total Net MW	Percentage of Net MW
		NG	NG Primary	NG Secondary		
Northeast ME	1	30	0	0	30	0%
NH	2	69	0	0	69	1%
MA / Boston	6	716	215	16	947	14%
Central MA	4	130	0	0	130	2%
Southeast MA	9	-21	332	1,509	1,820	27%
Western MA	3	0	0	431	431	6%
RI	4	1,171	0	281	1,452	22%
CT	1	50	0	0	50	1%
Southwest CT	9	215	745	785	1,744	26%
Total	**39**	**2,359**	**1,292**	**3,022**	**6,673**	**100%**

Q. What are the implications on the demand for natural gas in New England given the proposed generation retirements that primarily rely on nuclear, oil, and coal and capacity additions that primarily rely on natural gas?

A. The retirement of key generating facilities that relied on coal, oil and nuclear will likely increase the reliance on existing natural gas-fired and dual-fuel (i.e., natural gas/oil) generating units, as well as relying on incremental generation facilities, which are likely to be fueled by natural gas. Given these market trends, the demand for natural gas by the power generation segment will increase.

Q. Has ISO-NE expressed concern with respect to the increased reliance on natural gas-fired generation?

A. Yes, ISO-NE has raised concerns regarding the availability of natural gas to meet power generation demand, particularly in the winter heating season, and the associated impact on the reliability of the power grid due to the increased reliance on natural gas for power

32 Source: SNL Financial as modified by Sussex.

generation and the pipeline capacity constraints in the New England region.[33]

In addition, ISO-NE has raised concerns with respect to the regional emissions levels due to the increased reliance on oil- and coal-fired generation to maintain system reliability when natural gas is not available.[34] The ISO-NE has stated: "[w]ithout significant expansion of natural gas pipeline and LNG storage serving New England, the impacts on reliability, price, and emissions are likely to continue."[35]

Q. What role has state climate and greenhouse gas emission policies played in the increased demand for natural gas in New England?

A. The New England states have implemented several policies in an effort to mitigate greenhouse gas emissions. These policies include statewide greenhouse gas emissions reduction targets and renewable portfolio standards ("RPS").

According to the EIA, carbon dioxide ("CO_2") emissions in New England have declined by approximately 20.8 percent from 2000 to 2013.[36] However, CO_2 emissions from the electric power sector in New England declined by approximately 39.7 percent during this same period,[37] and New England experienced a significant increase in natural gas-fired generation. Furthermore, the decline in CO_2 emissions from the electric power sector is larger than the CO_2 emissions decline in any other sector.

Additionally, the New England states are approving policies to support the expansion of

33 See, ISO New England, 2015 Regional Electricity Outlook, February 26, 2015, at 15.
34 Ibid, at 17.
35 Ibid, at 18.
36 *Energy-Related Carbon Dioxide Emissions at the State Level, 2000-2013*, U.S. Energy Information Administration, Table 1, October 2015.
37 Ibid.

natural gas for heating in New England, due to the relative difference in the prices and carbon emissions of natural gas and oil. For example, Connecticut's 2013 Comprehensive Energy Strategy included a policy to expand natural gas availability to 300,000 homes and businesses, citing the lower emissions, affordability and reliability of natural gas.[38]

State targets for greater intermittent renewable resources, such as solar and wind, also require a greater level of dispatchable generation on reserve, which are typically natural gas-fired facilities. As ISO-NE stated in its 2014 Regional System Plan, "[t]he need for flexible resources to provide operating reserves as well as other ancillary services, such as regulation and ramping, will likely increase as a result of unit retirements and the addition of variable energy resources, particularly wind and PV."[39] Consequently, the demand for cheaper, cleaner fuel sources from both the power generation and heating sectors have driven demand for natural gas in the region. The evidence submitted by Company Witness James G. Daly addresses the reliance of ISO-NE on natural gas-fired generation to meet load fluctuations.

B. Supply Trends

Q. Are there certain natural gas supply trends that are influencing the New England natural gas market?

A. Yes, there are four primary trends that are influencing the New England natural gas market, thus affecting the cost of energy paid by New England consumers. Specifically,

[38] *2013 Comprehensive Energy Strategy for Connecticut*, Connecticut Department of Energy and Environmental Protection, February 19, 2013, at iv - v.
[39] ISO New England, Inc., 2014 Regional System Plan, November 6, 2014, at 13.

the four supply trends are:

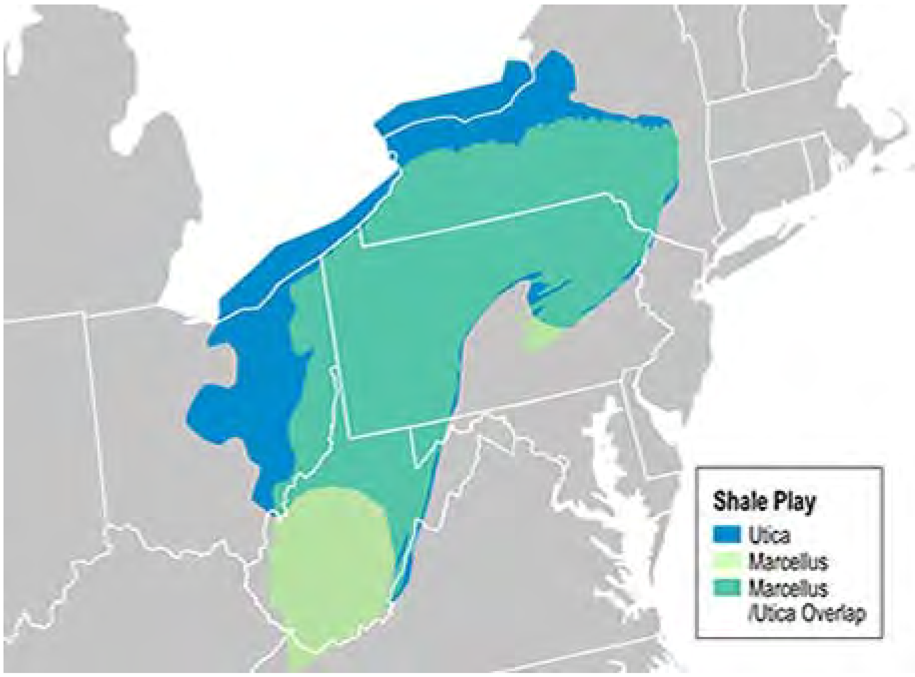
- A significant increase in natural gas production from the Marcellus and Utica shale basins;
- A decrease in natural gas supplies delivered from offshore Nova Scotia to New England;
- Declining and variable LNG imports into the New England region; and
- Constraints on natural gas pipelines that connect New England to the Marcellus and Utica shale basins.

1. <u>Appalachian Basin Natural Gas Production</u>

Q. Please describe the Appalachian supply area.

A. Located approximately 500 miles from central New England, the Appalachian Basin, including the Marcellus and Utica shale basins, encompasses areas in Ohio, West Virginia, and Pennsylvania where natural gas producers have successfully unlocked substantial natural gas production through improvements in drilling and production techniques. The location and proximity of the Marcellus and Utica shale basins are shown in Figure 7 below.

Figure 7: Marcellus and Utica Shale Basins[40]



Q. Has natural gas production from the Marcellus and Utica shale basins increased?

A. Yes. As illustrated in Figure 8, the total natural gas production from the Marcellus and Utica shale basins is approximately 20 Bcf/day, which is approximately ten times the production level of 2 Bcf/day in 2009/2010.

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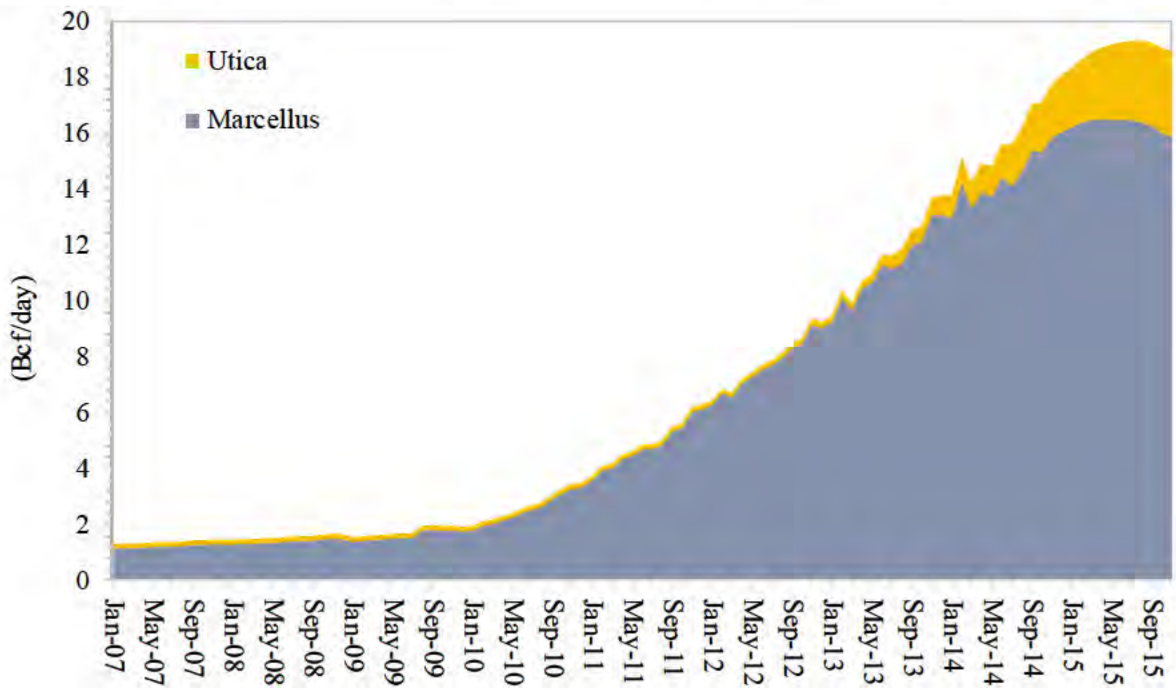
[40] U.S. EIA.

Figure 8: Marcellus and Utica Production (January 2007 – September 2015)[41]

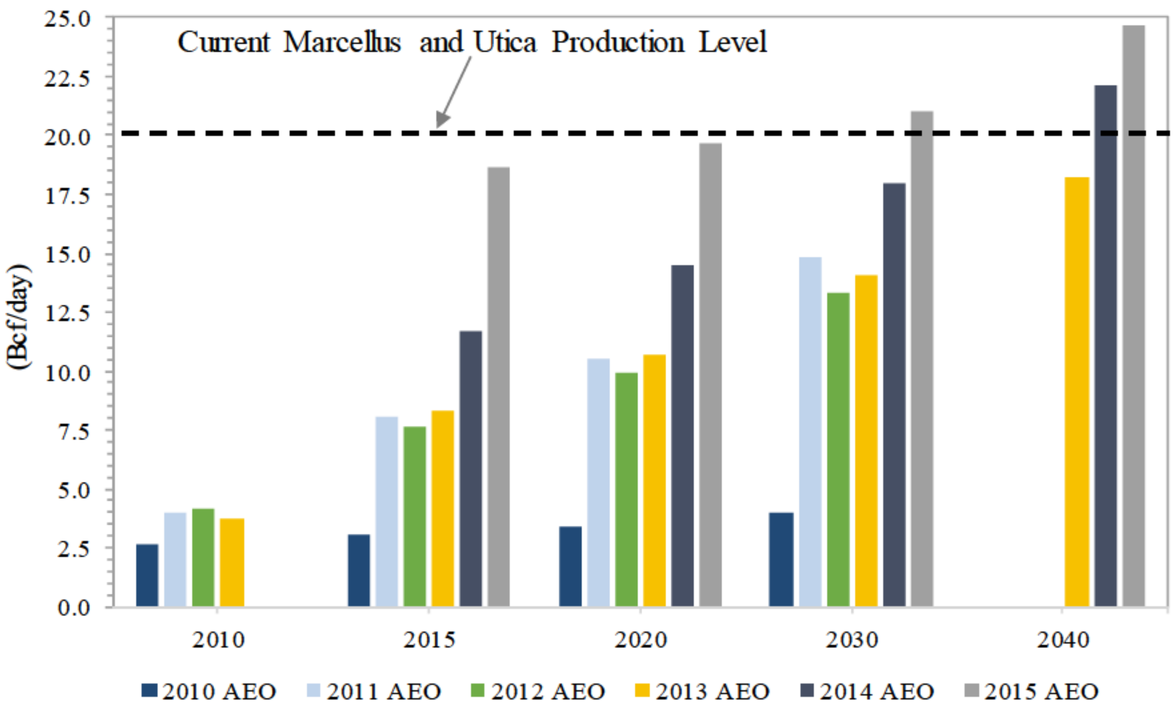


Q. Do long-term forecasts of natural gas production from the Marcellus and Utica shale basins indicate this level of production will continue?

A. Yes. Natural gas production from the Marcellus and Utica shale basins is forecasted to continue to grow through at least 2040. The EIA, for example, produces an annual 30-year production forecast in its Annual Energy Outlook ("AEO"). Figure 9 below depicts the current EIA AEO natural gas production forecast through 2040 for Marcellus and Utica, as well as the prior EIA natural gas production forecasts from 2010 through 2014. During this period, the EIA has consistently increased its production forecast to reflect faster than forecasted buildout of the Marcellus and Utica shale basins and enhanced production techniques.

41 U.S. EIA Drilling Productivity Report, October 13, 2015.

Figure 9: EIA AEO: Marcellus and Utica Shale Production Forecast (2010-2015)[42]



In its 2015 natural gas production forecast, EIA is forecasting that natural gas production from the Marcellus and Utica shale basins will increase by approximately 32 percent between 2015 and 2040. Of note, however, is that current natural gas production from the Marcellus and Utica shale basins has already exceeded the 2015 and 2020 natural gas production levels predicted by the 2015 EIA AEO forecast.

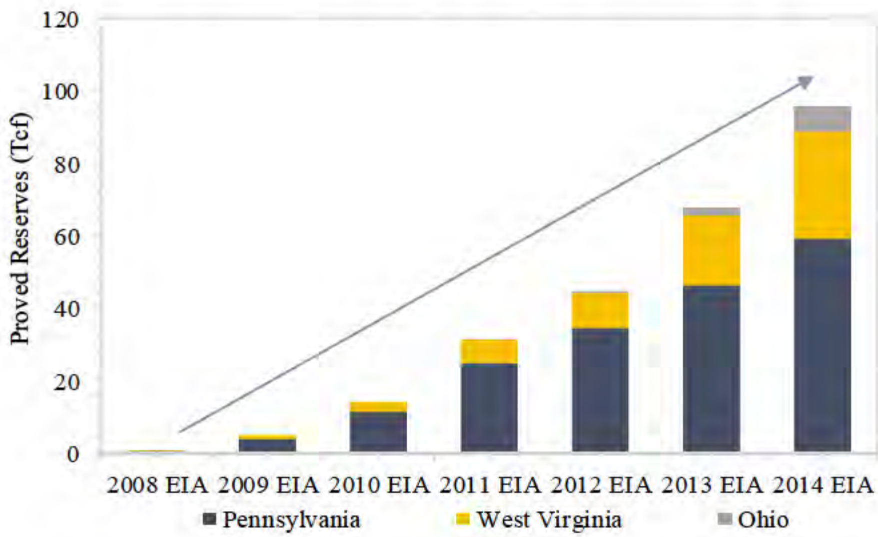
Q. To verify this production level is sustainable, have you reviewed estimates of the natural gas reserves or resources that are potentially available from the Marcellus and Utica shale basins?

A. Yes, both the EIA and the Potential Gas Committee ("PGC"), a research entity affiliated with the Colorado School of Mines, have produced recent estimates of the potential

42 U.S. EIA Annual Energy Outlooks produced between 2010 and 2014.

volume of natural gas that can be produced from the Marcellus and Utica basins. Figure 10 below, depicts the growth in the EIA's estimates of proved reserves for the states that encompass the majority of the Appalachian Basin production (i.e., Pennsylvania, West Virginia, and Ohio) between 2008 and 2014.[43]

Figure 10: EIA Proved Reserves (2008 – 2014)[44]



As illustrated above, in 2008, the EIA estimate included de minimis proved reserves in Pennsylvania and West Virginia, which, in aggregate, represented less than 0.1 Tcf of proved reserves. However, the EIA estimate of proved reserves has shown consistent, annual growth since 2008, resulting in a 2014 estimate of 95 Tcf.

43 For purposes of the EIA analysis, a proved reserve is defined as a reserve that has demonstrated with reasonable certainty (i.e., 90 percent probability or greater) to be recoverable from known reservoirs under the existing economic and operational conditions.

44 U.S. EIA, Estimate of Proved Reserves, Shale Gas, as of December 31st of each year. http://www.eia.gov/dnav/ng/ng_enr_shalegas_a_EPG0_R5301_Bcf_a.htm., accessed November 30, 2015.

Q. Please describe the PGC estimates of natural gas resources from the Marcellus and Utica shale basins.

A. The PGC produces a biennial estimate of the technically recoverable natural gas resources in the U.S.[45] The estimates are additive to the aforementioned proved reserves estimates provided by the EIA. PGC classifies its estimates amongst three resource categories defined by the PGC as:[46] Probable Resources,[47] Possible Resources,[48] and Speculative Resources.[49] Figure 11 below depicts the PGC estimates of potential resources as of 2010 and 2014.[50]

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45 http://potentialgas.org/what-we-do-2, accessed October 28, 2015. While the EIA estimates of proved reserve identify the economically recoverable resources under existing circumstances, the PGC estimate includes resources that are expected to be recoverable based on expected economic conditions, proximate resource performance and expected technological developments.

46 Ibid.

47 A probable resource is defined as a discovered but unconfirmed resource associated with known fields and field extensions, also undiscovered in new pools in both productive and nonproductive areas of known fields; http://potentialgas.org/what-we-do-2, accessed October 28, 2015.

48 A possible resource is an undiscovered resource associated with new field/pool discoveries in known productive formations in known productive areas; Ibid.

49 A speculative resource is an undiscovered resource associated with new field/pool discoveries in as-yet nonproductive areas; Ibid.

50 "Potential Supply of Natural Gas in the United States – Report of the Potential Gas Committee December 31, 2012," The Potential Gas Agency, Colorado School of Mines, April 2013 and "Potential Supply of Natural Gas in the United States – Report of the Potential Gas Committee December 31, 2014," The Potential Gas Agency, Colorado School of Mines, April 2015.

Figure 11: PGC Potential Resources Estimates in the Atlantic Region (2010 – 2014)[51]

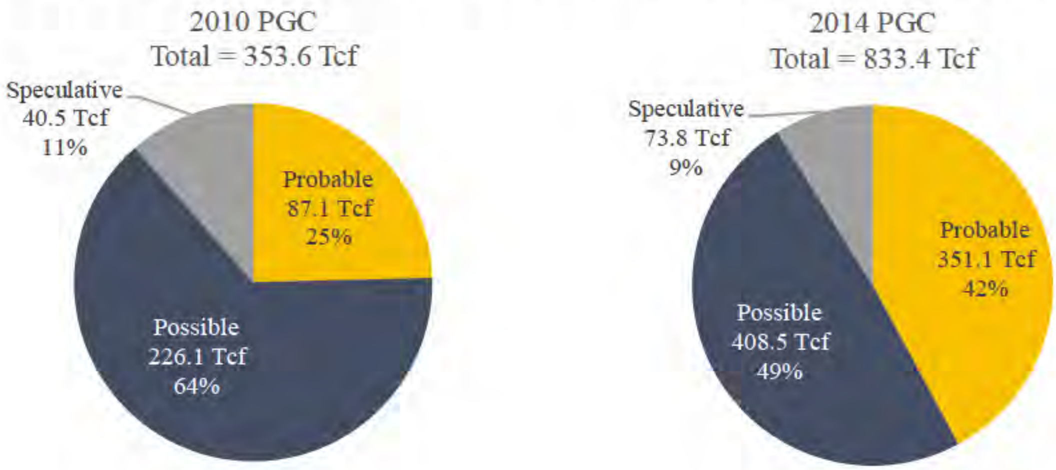


Figure 11 illustrates not only the growth in total Atlantic Region (i.e., Marcellus and Utica) potential resources, but the changes by resource estimate category. Specifically, the total estimate of Potential Resources in the Atlantic Region increcreased from approximately 354 Tcf to approximately 833 Tcf, or by 135 percent. More importantly, the Probable Resource category (i.e., the more certain of the three resource categories) increased from approximately 87 Tcf, or 25 percent, of the total resource estimate to approximately 351 Tcf, or 42 percent, of the total resource estimate, an increase of over 300 percent.

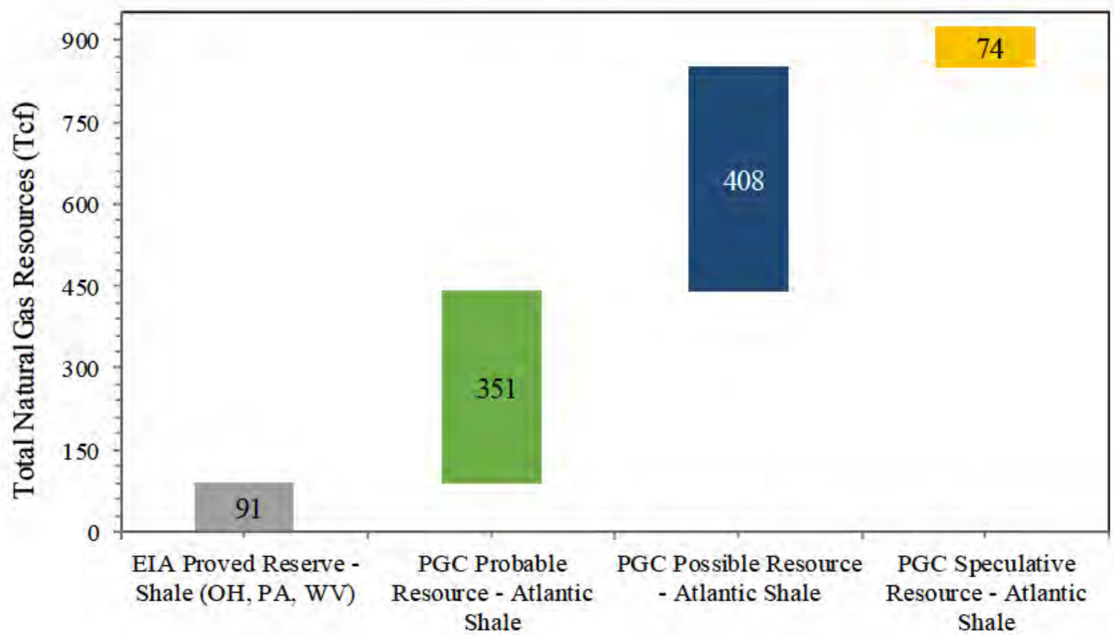
Q. Please provide an overview of the total natural gas available from the Marcellus and Utica region based on the EIA and PGC estimates?

A. The current estimates of the total natural gas that may be produced from the Marcellus and Utica shale basins are substantial. Figure 12 below illustrates the scale of the

[51] "Potential Supply of Natural Gas in the United States – Report of the Potential Gas Committee December 31, 2012," The Potential Gas Agency, Colorado School of Mines, April 2013 and "Potential Supply of Natural Gas in the United States – Report of the Potential Gas Committee December 31, 2014," The Potential Gas Agency, Colorado School of Mines, April 2015.

potential resource level by combining the EIA Proved Reserve and PGC Potential Resource estimates to derive the total resource potential from the Marcellus and Utica shale basins.

Figure 12: Combined EIA Proved Reserves and PGC Potential Resources for Marcellus and Utica Shale



To provide context, and assuming an annual overall U.S. natural gas consumption level of 26.7 Tcf,[52] the combined EIA proved reserves of shale natural gas and PGC potential resources in the Atlantic Region would provide sufficient supply for all U.S. natural gas demand for approximately 35 years.

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[52] The EIA notes that the 2014 annual consumption of natural gas in the U.S. was 26,698 Bcf or 27,563 PJ, which converts to approximately 73.1 Bcf/day or 75.5 PJ/day. *See*, U.S. Energy Information Administration, *Natural Gas Consumption by End Use*, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm, accessed November 2015.

2. Declining Offshore Nova Scotia Production

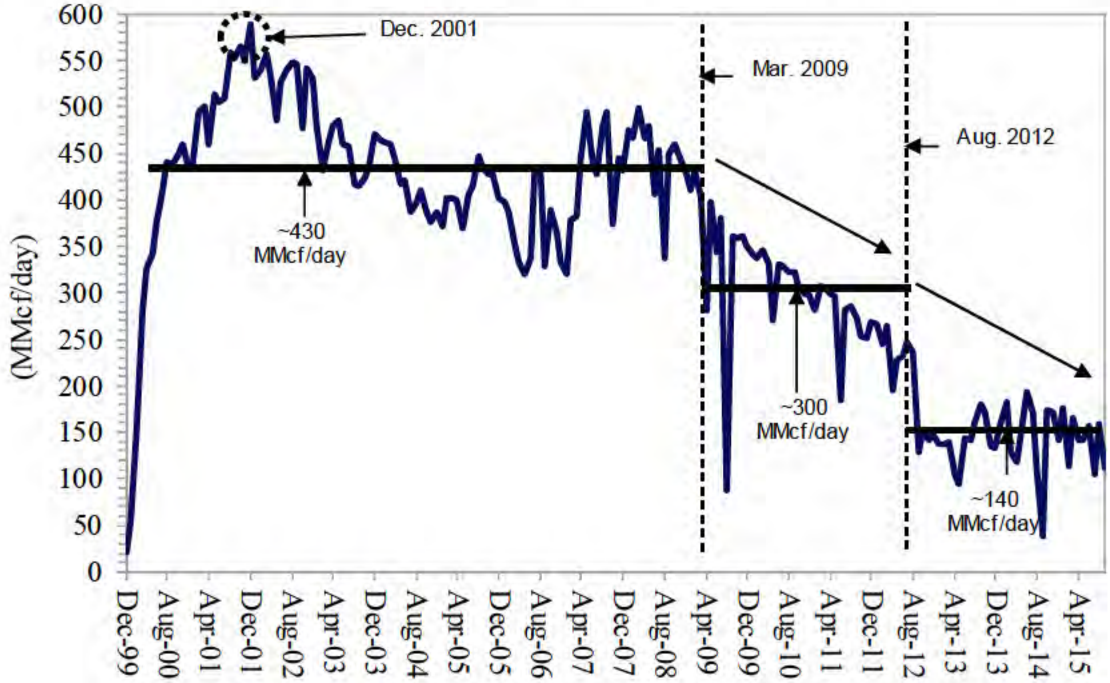
Q. Please describe the natural gas supplies from offshore Nova Scotia.

A. The natural gas supplies from offshore Nova Scotia are comprised of the Sable Offshore Energy Project ("SOEP"); and Deep Panuke Offshore Gas Development Project ("Deep Panuke"). The SOEP natural gas production was developed in late 1999, while Deep Panuke came on-line in August 2013.

Q. Please describe the decline in natural gas production from SOEP.

A. Although average daily production from SOEP was relatively stable over the December 1999 to March 2009 period, peaking at nearly 600 MMcf/day, subsequent production from SOEP has decreased significantly. As illustrated in Figure 13, average daily SOEP production declined from approximately 430 MMcf/day over the December 1999 to March 2009 period to approximately 140 MMcf/day since August 2012. Stated differently, the current average daily production level from SOEP is a nearly 70 percent decrease from the production levels experienced prior to March 2009.

Figure 13: Average SOEP Natural Gas Production (December 1999 – September 2015)[53]



Q. Please discuss the natural gas production from Deep Panuke.

A. As illustrated in Figure 14, natural gas production from Deep Panuke has been variable since its inception in August 2013. Although Deep Panuke was expected to produce approximately 300 MMcf/day,[54] actual average daily natural gas production from Deep Panuke peaked at approximately 280 MMcf/day in January 2014, and declined to approximately 170 MMcf/day in the winter of 2014/2015.

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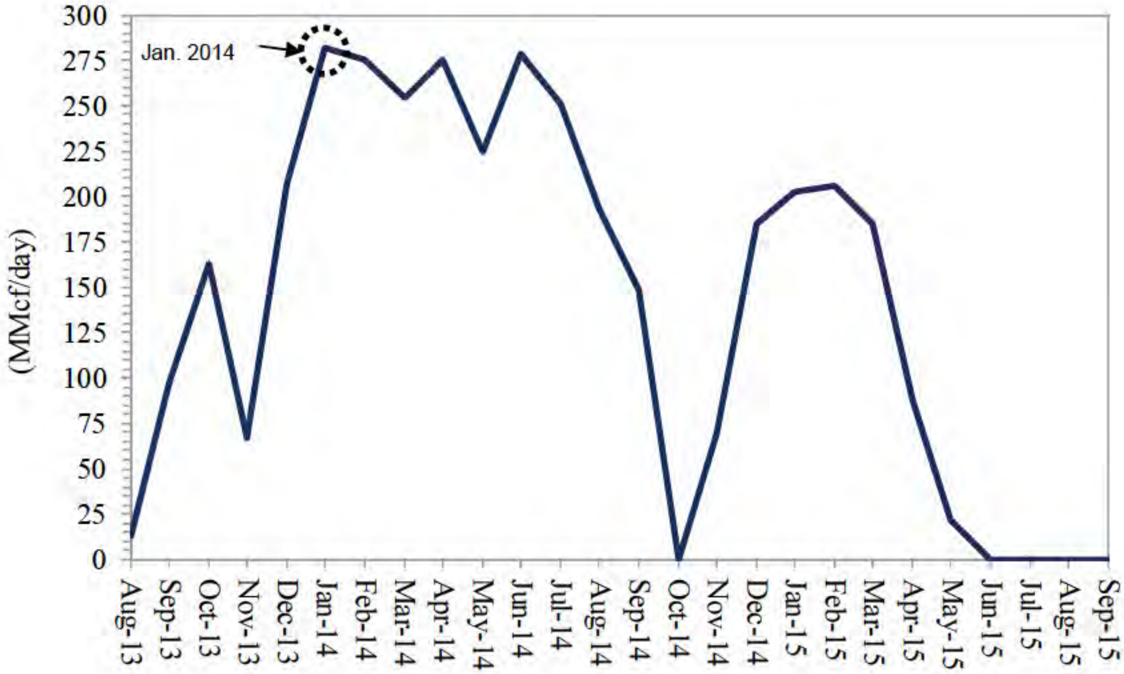
53 Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, accessed on November 3, 2015.

54 Nova Scotian Department of Energy; The Future of Natural Gas Supply for Nova Scotia. Prepared by ICF Consulting Canada, Inc., March 2013, at 35.

Figure 14: Average Deep Panuke Natural Gas Production (August 2013 – September 2015)[55]



Q. Has Encana Corporation recently adjusted its reserve estimate for Deep Panuke?

A. Yes. In 2015, the owner of the Deep Panuke facility, Encana Corporation ("Encana"), reduced the existing reserve estimate for Deep Panuke by approximately 50 percent.[56] Additionally, Encana halted production from Deep Panuke in May 2015, while announcing plans to produce natural gas only during the winter months.[57]

55 Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, accessed on November 3, 2015.

56 See, Natural Gas Intelligence, "Deep Panuke NatGas Reserves Halved by Encana", February 26, 2015. The reserve estimate was reduced from 400 Bcf to 200 Bcf.

57 See, The Chronicle Herald, "Deep Panuke resumes natural gas production", October 29, 2015.

Q. Have the Maritime Canada natural gas market participants initiated steps to diversify their gas supplies as a result of the decline in off-shore Nova Scotia natural gas production?

A. Yes, certain market participants in Maritime Canada, including Heritage Gas Limited, Irving Oil Terminal Operations Inc., and J.D. Irving Limited, have contracted to support new pipeline infrastructure such as the Atlantic Bridge project.[58]

3. <u>LNG Imports</u>

Q. Please discuss the trends related to the role of imported LNG in the New England region.

A. There has been significant variability in the volumes of imported LNG to the New England region. As illustrated in Figure 15, the average daily imported LNG volumes at the four LNG import facilities in the New England/Maritime Canada region have declined.[59] The two off-shore LNG importation facilities, Northeast Gateway and Neptune LNG, have received limited LNG deliveries since commencing service in 2009 and 2010,[60] respectively; while the GDF SUEZ Everett LNG and Canaport LNG facilities have experienced the same declining trend. The combined volume of imported LNG has declined by nearly 60 percent from a daily average of approximately 870 MMcf/day in winter 2010/2011 to approximately 380 MMcf/day in the first three months of 2015 (i.e.,

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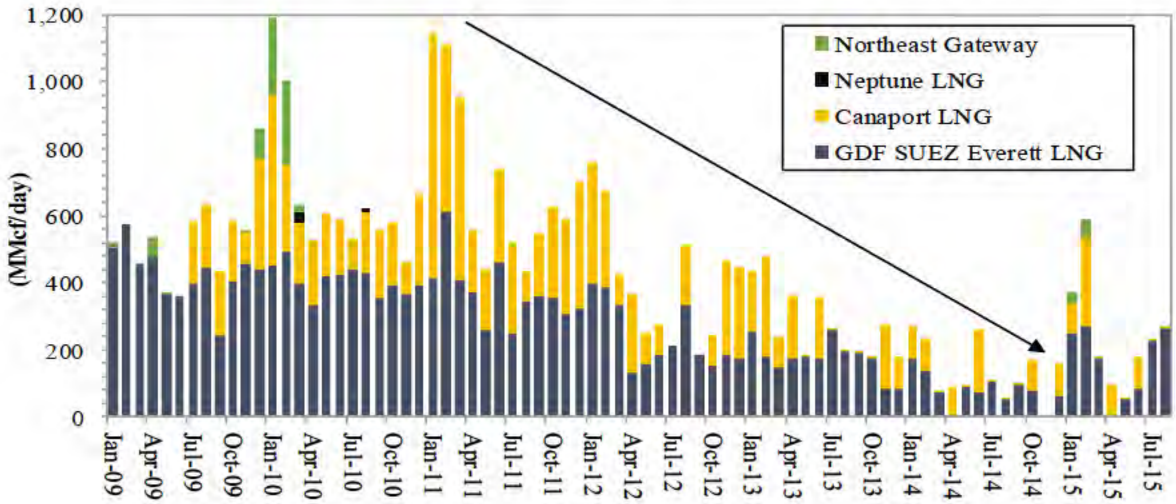
58 See, NEB, Market Snapshot: Deep Panuke moves to seasonal production and lowers reserve due to water influx, July 29, 2015.

59 The four LNG import facilities include the Everett Marine Terminal in Everett, MA ("GDF SUEZ Everett LNG"), the Neptune Deepwater Terminal ("Neptune LNG") located off the shore of Gloucester, MA, the Northeast Gateway facility owned by Excelerate Energy and located off the MA Coast ("Northeast Gateway"), and the Canaport LNG facility located near St. John, New Brunswick ("Canaport LNG").

60 The Neptune LNG facility ceased its ability to receive LNG deliveries in 2013 following a request by GDF SUEZ subsidiary, Neptune LNG, to the U.S. Maritime Administration to suspend its deep-water port permit for five years noting that "based upon various market conditions affecting the Northeast region's natural gas markets, the Neptune Port has remained inactive since its commissioning and will likely remain inactive for the foreseeable future." See, Letter to Mr. Francis J. Katulak, Senior Vice President, Neptune LNG LLC dated June 22, 2013.

January 2015 to March 2015).

Figure 15: Average Imported LNG Volumes (January 2009 – August 2015)[61]



Q. What factors have contributed to the decline and variability of imported LNG to the region?

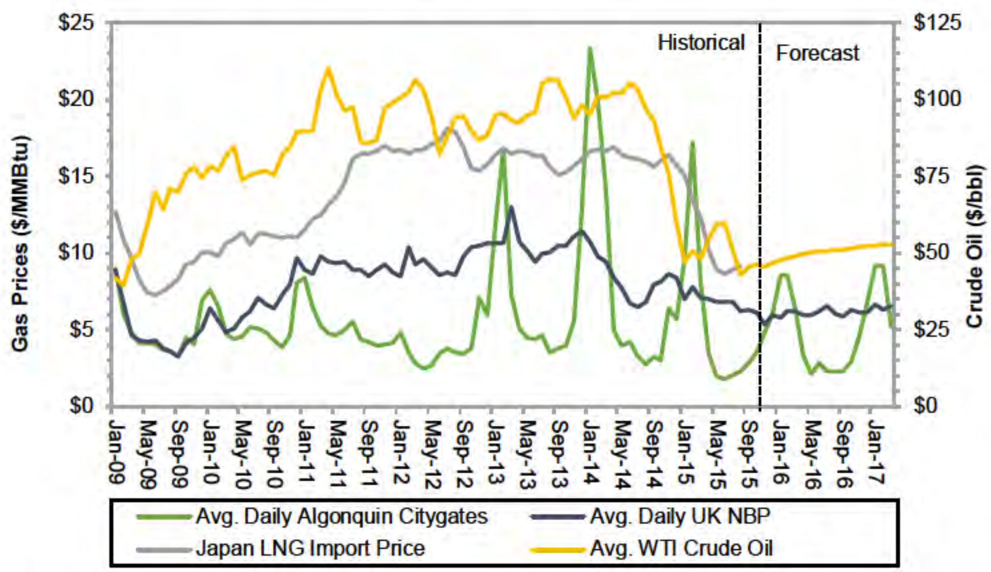
A. Since the imported LNG market is a global market, the New England/Maritime Canada region must compete with international markets for imported LNG supplies. The volume of LNG imported into the New England/Maritime Canada region is influenced by the demand for LNG in alternative markets (e.g., United Kingdom and Japan) and the associated price signals in those markets. As illustrated in Figure 16 below, the LNG prices in certain alternative markets have tracked the price of crude oil.[62] Stated differently, the volume of LNG available to New England may depend on the relative price signals of alternative markets that are priced off of an oil index, compared to the

[61] Sources: U.S. Department of Energy, LNG Annual and Monthly Reports, accessed on November 3, 2015; and National Energy Board, LNG - Shipment Details, accessed on November 3, 2015.

[62] See, U.S. Energy Information Administration, "Annual Energy Outlook 2015", April 14, 2015, at 22.

New England natural gas market price. Further, the New England natural gas market price (i.e., the price that may be compared to other LNG markets) is influenced by the existing pipeline constraints, thus limiting access to the prolific, low-cost natural gas supplies in the Marcellus and Utica shale basins.

Figure 16: LNG Market Signals (January 2009 – March 2017)[63]



Although the New England market experienced an increase in LNG cargoes during the 2014/15 winter, that increase was partially attributed to a reduction in global oil prices and expectations of high New England natural gas prices resulting from infrastructure constraints.

4. *__Pipeline Capacity Constraints into the New England Region__*

Q. Please provide an overview of the interstate pipeline infrastructure in New England.

A. There are five interstate natural gas pipelines that serve the New England region: (i)

[63] Sources: SNL Financial; and Bloomberg Professional.

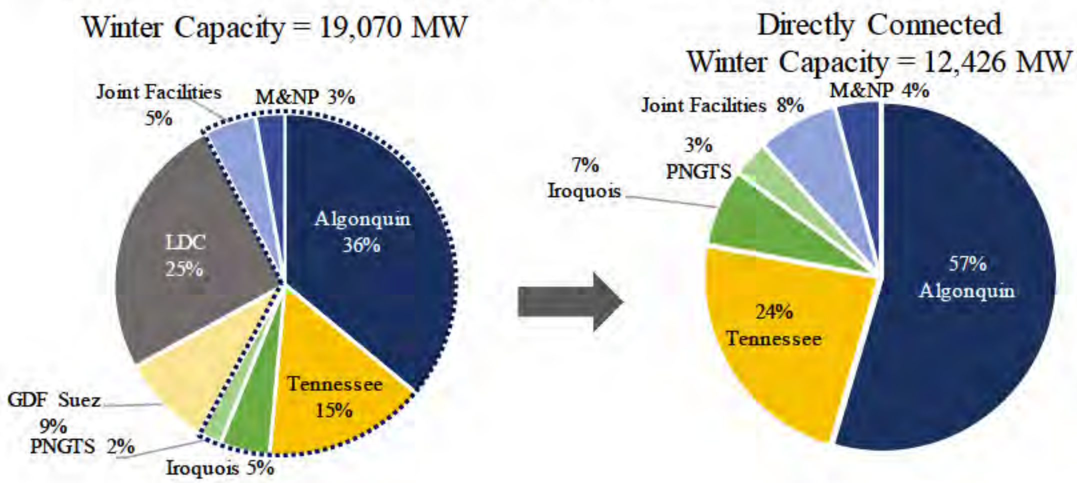
Algonquin; (ii) Tennessee; (iii) Iroquois; (iv) PNGTS; and (v) M&NP. Figure 17 presents the location of each of these pipeline systems.

Figure 17: New England Interstate Pipelines[64]

The Iroquois, PNGTS, and M&NP pipelines primarily, but not exclusively, deliver natural gas into the Algonquin and Tennessee pipelines for transportation to power generators and LDC systems located along those pipelines. Figure 18 depicts the amount of natural gas-fired and dual-fuel power generation served by each of the New England pipelines, LDCs, and GDF SUEZ. In addition, Figure 18 depicts the natural gas-fired and dual-fuel generation served directly by the interstate pipelines.

64 Source: SNL Financial.

Figure 18: New England Gas-fired Power Generation Winter Capacity[65]



As shown in Figure 18 and focusing on the natural gas-fired and dual-fuel generation directly connected to pipelines, Algonquin serves approximately 57 percent of the total natural gas-fired and dual-fuel generation capacity directly connected to an interstate pipeline in New England. Tennessee directly serves approximately 24 percent of the natural gas-fired and dual-fuel generation directly connected to an interstate pipeline in New England. Lastly, PNGTS, Iroquois, M&NP and Joint Facilities are directly connected to 3 percent, 7 percent, 4 percent, and 8 percent of the natural gas-fired and dual-fuel generating capacity connected to an interstate pipeline, respectively.

65 Based on Sussex analysis of publicly available information. Sources: U.S. EIA, Form EIA-860 Detailed Data for 2014, release date October 21, 2015; ISO New England, CELT Report: 2015-2024 Forecast Report of Capacity, Energy, Loads, and Transmission, May 1, 2015; and Levitan & Associates, Inc., Gas-Electric System Interface Study: Existing Natural Gas-Electric System Interfaces, Appendix 4, April 4, 2014. The percentages do not sum to 100 percent because Ocean State Power I/II can be served by either Algonquin or Tennessee.

Q. Please discuss the pipeline capacity constraints into the New England region.

A. From the south, both the Algonquin and Tennessee systems are fully subscribed and have experienced significant pipeline capacity constraints due to increased utilization of pipeline capacity into the region over the past several years. As noted by Algonquin, the Southeast and Cromwell compressor stations (i.e., two of the major compressor stations into the New England region) have "operated at [an] essentially 100% load factor" over the past four to five years.[66] In addition, Algonquin has stated that winter season nominations for west-to-east transportation has been 400,000 to 500,000 MMBtu/day higher than current capacity.[67]

Similarly, Tennessee has reported interruptible transportation restrictions at Compressor Station 245 in New York for 100 percent of the days during the past two winters (i.e., the winters of 2013/2014 and 2014/2015), and over 98 percent of the days in the past two summers (i.e., the summers of 2014 and 2015).[68] Moreover, Tennessee recently stated the following to the Massachusetts Department of Public Utilities ("MA DPU"):

> To highlight the inadequate pipeline capacity into and within New England, Tennessee receives requests nearly every day of the year for transportation service to or within New England that greatly exceed Tennessee's operating capacity. Specifically, in the winter (i.e., November through March), Tennessee is required each day to restrict shippers' requested volumes for non-firm service. The extent of these restrictions over the past three winters ranges from an average low of approximately 0.7 Bcf/d, to an average high of 1.4 Bcf/d, with sustained periods of significantly greater restrictions (e.g., restricting up to 2.6 Bcf/d of shipper requests during the winter of 2014/2015). These required

[66] See, D.P.U. 15-37, Spectra Energy, Initial Comments, at 8, 9 (June 15, 2015).
[67] Ibid., at 8.
[68] See, Kinder Morgan, Presentation at the 2014 Shipper Meeting, October 1-3, 2014, at 14, 21; and Kinder Morgan, Pipeline Operations Update, October 8, 2015, at 13, 19.

> restrictions on requested service that are affecting New England occur at multiple locations along Tennessee's system, and importantly, usually impact all priorities of Tennessee's various interruptible transportation services.[69]

Tennessee has also noted an increasing number of operational flow orders ("OFOs") over the past two years, which are typically issued by a pipeline to protect the operational integrity of the system. Specifically, for Tennessee Zones 5 and 6, there were OFOs issued on 35 days in 2013/2014 and 40 days in 2014/2015.[70]

The high level of utilization, the restrictions on available capacity, and the increasing number of days with OFOs are indicative of the pipeline constraints into the New England region. These constraints are ultimately reflected in the electricity prices experienced by New England consumers.

C. Market Price Signals

Q. Please provide an overview of the New England natural gas price trends.

A. The natural gas prices in New England have historically been at a premium to other markets (i.e., the adjacent Mid-Atlantic region and the Gulf Coast). However, over the past few years, natural gas prices in the New England region have been markedly high and volatile. To provide context and as summarized in Table 4, Sussex compared the average daily spot prices for New England, as represented by the Algonquin CityGates ("ALGCG") price index to the average daily spot prices for the adjacent Mid-Atlantic region (as represented by the TETCO M3 price index) and the Gulf Coast (as represented

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69 Tennessee Gas Pipeline Company, L.L.C., Initial Comments, Docket No. D.P.U. 15-37, Investigation by the Department of Public Utilities into the Means by Which New Natural Gas Delivery Capacity May be Added to the New England Market, June 15, 2015, at 13.

70 See, Kinder Morgan, Pipeline Operations Update, October 8, 2015, at 7.

by the Henry Hub price index).

Table 4: Average Daily Natural Gas Spot Prices ($/MMBtu)[71]

Split-Yr (Nov-Oct)	Annual (Nov-Oct)		
	ALGCG	TETCO M3	Henry Hub
2010/2011	$ 5.43	$ 5.06	$ 4.13
2011/2012	$ 3.53	$ 2.94	$ 2.72
2012/2013	$ 6.48	$ 3.94	$ 3.65
2013/2014	$ 8.35	$ 5.24	$ 4.39
2014/2015	$ 5.32	$ 2.97	$ 2.93
Historical Avg. (2010/11-2014/15)	**$ 5.82**	**$ 4.03**	**$ 3.56**

As illustrated by Table 4, over the past five split-years, the average annual New England natural gas price (i.e., ALGCG) was over $5.80/MMBtu. In contrast, the average annual price in the Gulf Coast (i.e., Henry Hub) was $3.56/MMBtu, or approximately $2.25/MMBtu lower than the New England price; and the average annual price for the adjacent Mid-Atlantic region (i.e., TETCO M3) was approximately $4.00/MMBtu, or approximately $1.80/MMBtu lower than the New England price.

Q. Have the seasonal natural gas prices experienced similar or even greater basis premiums?

A. Yes. Seasonal basis premiums have shown an even greater spread between the New England region, adjacent Mid-Atlantic region, and the Gulf Coast. Table 5 below presents the historical seasonal basis premium between 2008/2009 to 2014/2015.

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71 Source: SNL Financial.

Table 5: Average Daily Natural Gas Basis Differentials ($/MMBtu)[72]

Split-Yr (Nov-Oct)	Winter (Nov-Mar) ALGCG-Henry Hub	Winter (Nov-Mar) TETCO M3-Henry Hub	Winter (Nov-Mar) ALGCG-TETCO M3	Summer (Apr-Oct) ALGCG-Henry Hub	Summer (Apr-Oct) TETCO M3-Henry Hub	Summer (Apr-Oct) ALGCG-TETCO M3
2008/2009	$ 1.70	$ 1.51	$ 0.19	$ 0.37	$ 0.34	$ 0.04
2009/2010	$ 1.06	$ 0.79	$ 0.27	$ 0.40	$ 0.34	$ 0.07
2010/2011	$ 2.47	$ 1.88	$ 0.59	$ 0.48	$ 0.26	$ 0.21
2011/2012	$ 1.09	$ 0.28	$ 0.81	$ 0.61	$ 0.17	$ 0.44
2012/2013	$ 6.17	$ 0.67	$ 5.50	$ 0.48	$ 0.03	$ 0.45
2013/2014	$ 10.46	$ 3.89	$ 6.56	$ (0.62)	$ (1.29)	$ 0.67
2014/2015	$ 6.01	$ 1.84	$ 4.17	$ (0.17)	$ (1.23)	$ 1.06
Historical Avg. (2010/11-2014/15)	$ 5.24	$ 1.71	$ 3.53	$ 0.15	$ (0.41)	$ 0.57

Between 2010/2011 and 2011/2012, the average New England winter basis premium relative to the Mid-Atlantic region was approximately $0.70/MMBtu, and increased to approximately $5.40/MMBtu for the 2012/2013 through 2014/2015 period. The summer basis premium between the ALGCG and the TETCO M3 price indices has increased every year over the seven-year period reaching an average of $1.06/MMBtu in 2015. As a result, the New England region would benefit from new pipeline capacity that increases access to lower cost gas supplies.

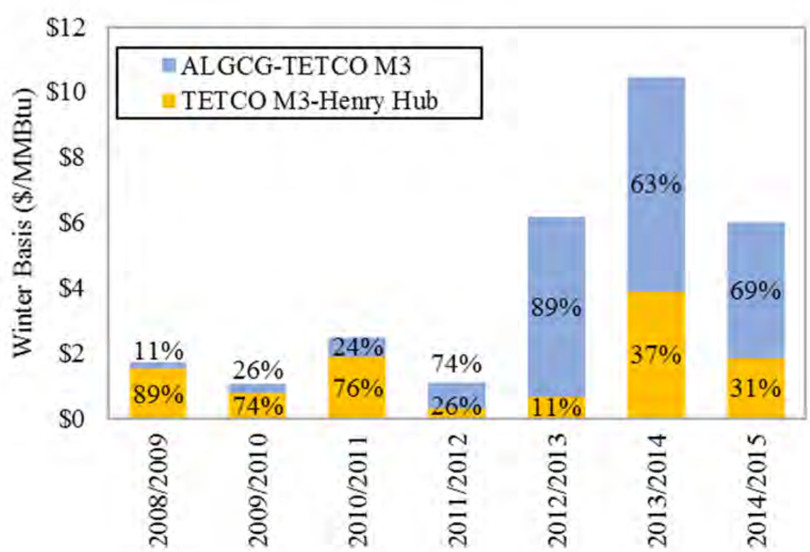
Q. Please elaborate on the ALGCG, TETCO M3, and Henry Hub basis.

A. If the ALGCG to Henry Hub basis is viewed as two components (i.e., TETCO M3 to Henry Hub basis and ALGCG to TETCO M3 basis), the portion represented by the TETCO M3 to Henry Hub basis represents the basis premium between the Gulf Coast

72 Source: SNL Financial.

and the Mid-Atlantic regions which has significantly decreased. In contrast, the portion derived from the ALGCG to TETCO M-3 basis, representing the basis premium between New England and the Mid-Atlantic, has significantly increased (i.e., illustrative of the increase in gas supply in the Marcellus and Utica shale basins coupled with the pipeline constraints between New England and the Mid-Atlantic). Figure 19 below illustrates these two components of the New England basis and how those components have changed over time.

Figure 19: Historical Winter Basis Differentials[73]



As illustrated by Figure 19, over the 2008/2009 – 2010/2011 period, the New England to Mid-Atlantic basis comprised approximately 20 percent of the basis between New England and the Gulf Coast; however, over the 2011/2012 to 2014/2015 time period, the New England to Mid-Atlantic basis comprised 75 percent of that basis value. The

[73] Sources: SNL Financial; and Bloomberg Professional.

increase of the basis between New England and the Mid-Atlantic reflects the pipeline constraints that exist between the Mid-Atlantic and New England.

Q. How often does New England confront these high-basis premiums?

A. The frequency of these high-basis premium days is increasing. As shown in Table 6 below, the ALGCG to TETCO M3 basis exceeded $5.00/MMBtu in at least 49 days in each of the three most recent split-years; whereas, the ALGCG to TETCO M3 basis exceeded $5.00/MMBtu a total of 4 days over the 2010/2011 to 2011/2012 period. Focusing on the cumulative number of days when the basis between ALGCG and TETCO M3 exceeded $2.00 MMBtu results in 121 days, 108 days, and 137 days in 2012/2013, 2013/2014, and 2014/2015, respectively. Lastly, the ALGCG to TETCO M3 basis exceeded $1.00/MMBtu a total of 158 days in 2012/2013, 161 days in 2013/2014, and 228 days in 2014/2015.

Table 6: Frequency of Observations[74]

LGCG-TETCO M3 Basis Differential ($/MMBtu)	Number of Days					
	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	Cumul. 2014/2015
≥ $5.00	2	2	49	68	49	49
≥ $2.00 and <$5.00	10	15	72	40	88	137
≥ $1.00 and <$2.00	22	43	37	53	91	228
≥ $0.50 and <$1.00	41	96	44	77	54	
≥ $0.00 and <$0.50	265	202	162	122	74	
<$0.00	25	8	1	5	9	

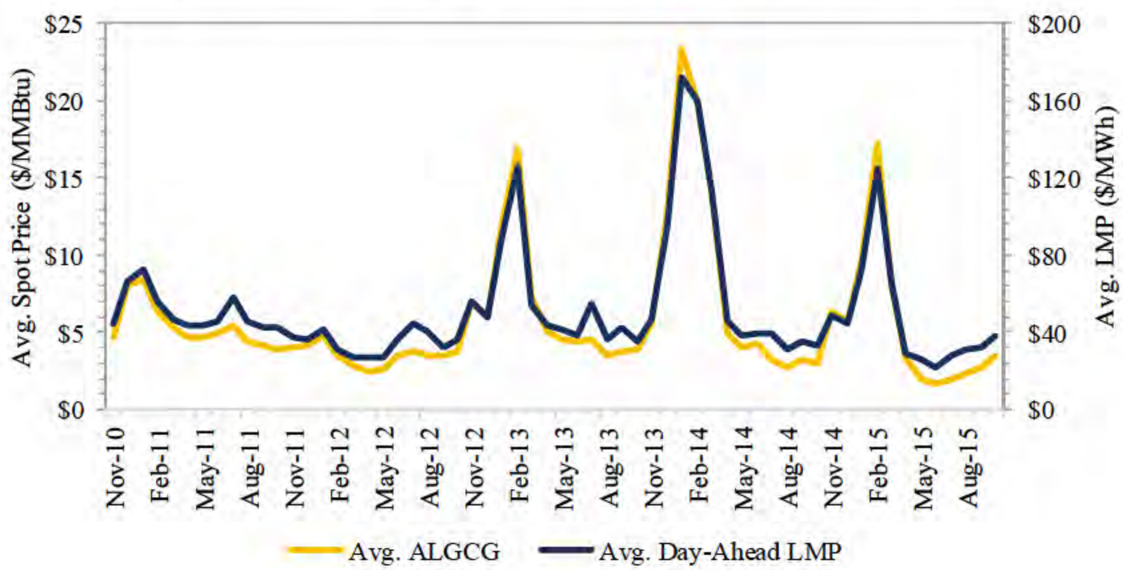
Q. Do the changes in New England natural gas prices impact the wholesale energy prices?

A. Yes. On a daily basis, New England winter natural gas and wholesale power prices have a correlation coefficient of approximately 0.91 (please see figure below). Therefore,

74 Source: SNL Financial.

since natural gas-fired generation is generally the marginal fuel for ISO-NE, a reduction in New England natural gas prices will decrease the wholesale power prices in the region.

Figure 20: New England Winter Power Price Correlation[75]



Q. Do New England consumers currently pay the highest electric rates in the continental U.S?

A. Yes, they do. As shown in Figure 21, since 2000 New England consumers have paid electric rates that on average were more than 54 percent greater than the average rate paid by U.S. consumers outside of New England. During this period, New Hampshire customers have paid electric rates that were generally slightly above the New England average.

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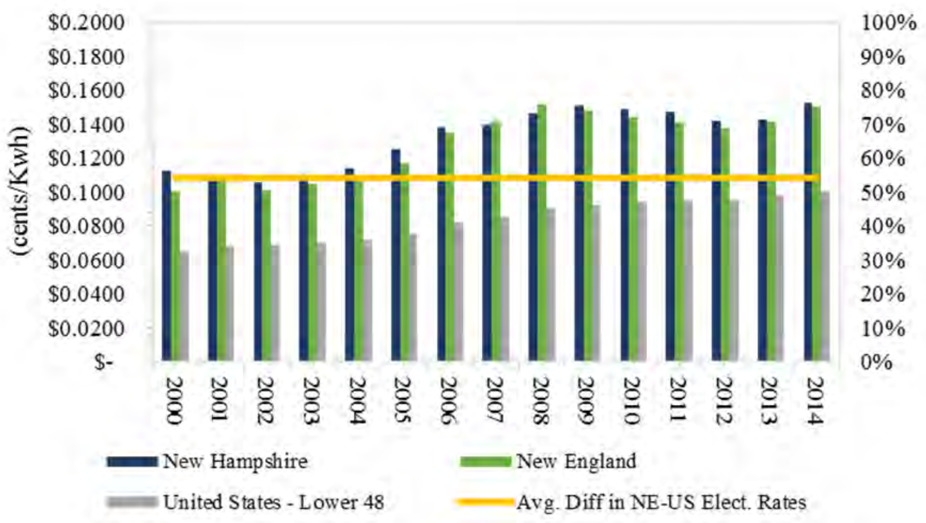
75 Sources: SNL Financial; and ISO New England, SMD Hourly Data for 2010 through 2015, accessed on November 9, 2015.

Figure 21: New England Retail Electric Rates (2000-2014)[76]



D. Market Context Conclusions

Q. Please summarize your conclusions related to the power and natural gas markets described above.

A. The demand for natural gas in New England is expected to continue to increase, driven primarily by the power generation segment. Amplifying growth from the power generation segment is over 4,200 MW of power generation that has been retired or is expected to retire by 2019. The electricity generated by the retiring units is likely to be replaced by natural gas-fired generating capacity, as 6,000 MW of natural gas-fired generation is in various stages of development in ISO-NE.

Contemporaneous with the growth in natural gas demand, certain of the existing natural gas supply sources to New England are in decline (i.e., off-shore Nova Scotia production), subject to international price drivers (i.e., imported LNG), or access is

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[76] Source: U.S. EIA Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions.

constrained (i.e., the pipeline constraints on Algonquin and Tennessee).

These changing natural gas demand and supply trends have resulted in significant price increases in both natural gas and power prices for New England customers. Therefore, access to low cost and prolific gas supply basins (i.e., Marcellus and Utica shale) will place downward pressure on natural gas prices, resulting in lower electricity prices.

IV. Competitive Solicitation Process

Q. Did Eversource utilize a competitive solicitation process as part of their decision making process regarding the Access Northeast project?

A. Yes. As discussed in more detail in the testimony of Company Witness James G. Daly, Eversource has been engaged in a process to address New England's persistently high wholesale power prices since December 2013. As a result of the efforts of various market participants to address high wholesale power prices, the Commission and the MA DPU initiated proceedings to review potential solutions to high wholesale electricity prices, including Commission Docket No. IR 15-124, and the MA DPU's recent decision, EDC Contracting for Gas Capacity, D.P.U. 15-37 (2015) ("D.P.U. 15-37"). Subsequent to the issuance of D.P.U. 15-37 and the Report on Investigation into Potential Approaches to Mitigate Wholesale Electricity Prices prepared by the Staff of the New Hampshire Public Utilities Commission in Docket No. IR 15-124, the Eversource EDCs and National Grid jointly developed a competitive solicitation process, which resulted in the issuance of an RFP to various regional natural gas industry participants.

Q. Please describe the recipients of the RFP?

A. The RFP was distributed to six sponsors or owners of natural gas pipelines including: (i)

Algonquin and M&NP-U.S.; (ii) Tennessee; (iii) PNGTS; (iv) Millennium Pipeline Company, LLC ("Millennium"); (v) Iroquois; and (vi) Granite State Gas Transmission, Inc. ("Granite State"). Additionally, the following three imported LNG suppliers received the RFP: (i) Repsol; (ii) GDF SUEZ; and (iii) Excelerate Energy L.P. ("Excelerate"). Each of the recipients of the RFP are described in greater detail in Attachment EVER-JMS–3.

Q. Please describe the RFP that was issued by the Eversource EDCs and National Grid.

A. The RFP issued by the Eversource EDCs and National Grid was posted on each company's public website and contained the following four primary sections:[77]

- Introduction – This section included an overview of D.P.U. 15-37 and the type of services sought by the Eversource EDCs and National Grid.
- Background – This section described the wholesale electricity pricing challenge confronted by the regional utilities.
- Proposal Deadline – The Proposal Deadline section included a review of the: (i) objective of the RFP; (ii) requirements for the services procured; (iii) types of services and operational flexibility required by the EDCs; (iv) quantity of services that would be considered by the EDCs; and (v) procedures and a schedule for the competitive solicitation process. In addition, this section included a description of the documents and information that were required to be submitted in response to the RFP.

[77] The RFP is posted on the Eversource website at: https://www.eversource.com/content/ema-c/about/doing-business-with-us/energy-supplier-information/pipeline-capacity-supply-procurement-(massachusetts).

- Submission Requirements – This section included the deadline for submitting responses to the RFP and a description of the certifications that must be made by a respondent to the RFP. This section also noted how the proposals were to be evaluated, and that receipt of the requisite approvals was a required condition precedent for selecting an offer.

In addition, the RFP included a form of a precedent agreement to be used by RFP respondents.

Q. Did the RFP state that conforming proposals should represent a viable, regional solution that would impact the reliability and wholesale price concerns confronted by New Hampshire consumers?

A. Yes. The RFP made it clear that the Eversource EDCs and National Grid were seeking natural gas delivery options to address reliability concerns and to solve the challenge of increased wholesale natural gas prices and resultant high power prices. The specific requirements were that the service must include all costs necessary to deliver natural gas to the affected power generators on a firm basis for the term of the contract (i.e., at least fifteen years), and the RFP required that the proposed services should have sufficient flexibility to meet the needs of natural gas-fired generation that frequently must be dispatched on limited notice and run at higher levels during on-peak hours. The RFP specified a minimum quantity of 500,000 MMBtu/day and maximum quantity of 2,000,000 MMBtu/day, and required proponents to include a maximum rate or a cap on cost-of-service based charges.

Additionally, potential RFP respondents were given an opportunity to submit questions to

Eversource EDCs and National Grid if the potential respondents required clarity regarding certain aspects of the RFP. The potential respondents' questions were edited to remove the names of the inquiring entities and the responses were provided to all potential respondents.[78] In aggregate, Eversource EDCs and National Grid received and responded to 39 questions from potential respondents. Lastly, the Eversource EDCs and National Grid contacted certain respondents for additional follow-up information.

Q. Was the RFP and the competitive solicitation process reasonably structured to solicit a range of alternatives regional solutions to the high natural gas and power prices?

A. Yes. The RFP was specifically designed to express the scope of services requested by the EDCs (i.e., alternatives representing a regional solution), while providing sufficient flexibility in the bid responses to permit a range of natural gas delivery options. The structure of the RFP was informed by the fact that multiple recipients of the RFP had participated in the Massachusetts D.P.U. 15-37 proceeding, including Algonquin/Spectra Energy Partners, Tennessee, PNGTS, GDF SUEZ and Repsol. In addition, subgroups of these entities have been involved in similar proceedings in New Hampshire and Maine during the prior two years.

Q. Please list the proposals received by the EDCs in response to the RFP.

A. The proposals received in response to the RFP are summarized in Table 7 below.

78 The EDCs received one question that was specific to a single entity and the response to that question was provided solely to that respondent.

Table 7: RFP Response Summary

Sponsor	Project Name	Brief Description	Daily Deliverability
Algonquin	Access Northeast	Pipeline expansions combined with LNG storage at Acushnet, MA	900,000 MMBtu/Day
Tennessee	Northeast Energy Direct	Greenfield pipeline construction; possible new LNG storage facility	[redacted]
PNGTS	PNGTS Expansion	Joint proposal with Iroquois and TransCanada, pipeline expansion	[redacted]
Iroquois	Constitution to Algonquin	Pipeline expansion	[redacted]
GDF SUEZ	N/A	Imported LNG options	[redacted]
Repsol	N/A	Imported LNG	[redacted]
Stolt LNGaz	N/A	New build LNG storage and delivery from Quebec	[redacted]

Q. Please describe the Tennessee NED project proposal.

A. The NED project is sponsored by Tennessee, an indirect subsidiary of Kinder Morgan, Inc., along with affiliates of Liberty Utilities and UIL Holdings. The project consists of two segments:

(i) A Supply Path segment that includes approximately 174 miles of greenfield pipeline and pipeline loop designed to transport between 700,000 and 1,200,000 MMBtu/day between the Tennessee 300 Line in Pennsylvania and Wright, NY; [79] and

(ii) A Market Path segment consisting of 188 miles of new, greenfield pipeline and pipeline laterals intended to transport between 550,000 and 1,300,000 MMBtu/day

[79] See, Tennessee Gas Pipeline Company, L.L.C., Application of Tennessee Gas Pipeline Company, L.L.C. for a Certificate of Public Convenience and Necessity to Construct, Install, Modify, Operate, and Maintain Certain Pipeline and Compression Facilities and to Abandon Facilities, FERC Docket No. CP16-21-000, November 20, 2015.

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from Wright, NY to Dracut, MA.[80]

The aggregate construction cost for the Market Path segment is estimated to be $3.3 billion, while the Supply Path segment is estimated to be $1.8 billion.[81]

As proposed, the Tennessee NED project would provide up to [redacted] of natural gas transportation capacity from Wright, NY[82] to an interconnection with the Joint Facilities of M&NP and PNGTS at Dracut, MA (i.e., the market path segment). The cost of this capacity ranged from [redacted] for a contract term of 20 years and ratable hourly service.[83] The Tennessee NED project included an option to procure upstream transportation capacity between the Tennessee 300 Line within the Marcellus/Utica shale basins and the NED Market Path receipt point at Wright, NY at an additional cost of [redacted] (i.e., the Supply Path segment). In addition, the NED proposal included [redacted]

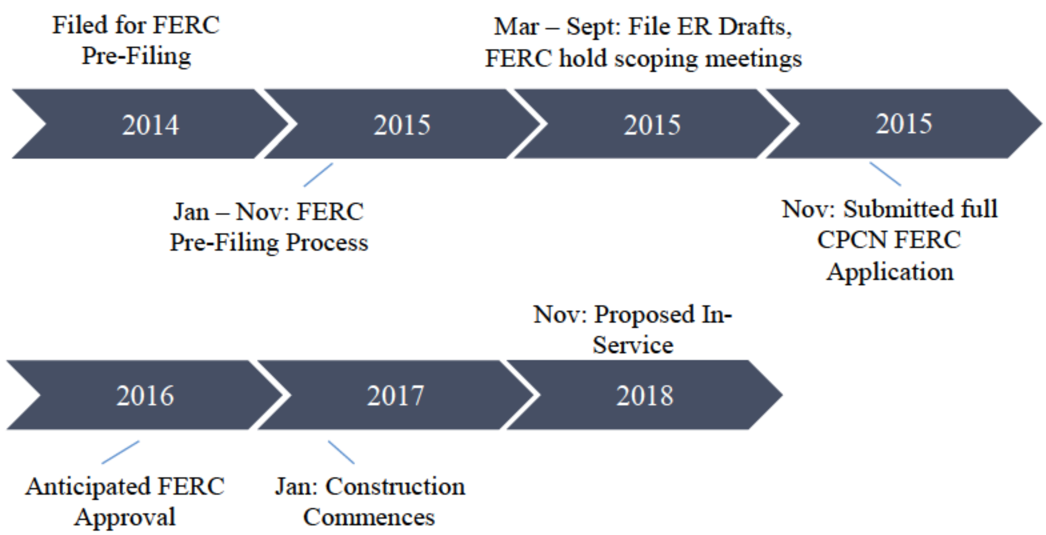
Shippers on the NED project would be capable of transporting natural gas to power generators connected to the new NED pipeline or the existing Tennessee 200 Line. To provide natural gas to the remaining New England power generators, natural gas could be

80 Ibid.
81 Ibid.
82 Wright, NY represents an existing interconnection between Tennessee's 200 Line and the Iroquois pipeline. It is not currently a pricing point or trading hub. With the development of the NED project and the Constitution Pipeline project, Tennessee has stated its intent to begin offering hub services.
83 [redacted]

transported from Dracut, MA or Mendon, MA at additional cost on the interconnecting downstream pipeline, subject to the appropriate facility additions, contracting structures, and rates.

The sponsors of the NED project submitted the CPCN application to FERC on November 20, 2015. The sponsors of the NED project currently expect to commence construction in January 2017, with a scheduled in service date in November 2018.[84] Figure 22 provides a more a detailed depiction of the project development timeline.

Figure 22: Tennessee NED Project Development Timeline



Q. Please describe the PNGTS Expansion project.

A. The PNGTS Expansion project is sponsored by PNGTS, an indirect subsidiary of TransCanada PipeLines Limited ("TCPL") and Gaz Métro. As proposed, the project is designed to transport via the Iroquois, TCPL, and PNGTS pipelines approximately

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84 http://www.kindermorgan.com/pages/business/gas_pipelines/east/neenergydirect/timeline.aspx accessed November 13, 2015.

[redacted] from Wright, NY to PNGTS.

The PNGTS Expansion project will require incremental construction on the Joint Facilities, which PNGTS shares with M&NP, and installation of additional compression on certain affiliated upstream pipelines to deliver additional volume to PNGTS.[85] Installation of the required facilities is expected to be completed in November 2017. The project has not yet begun the FERC pre-filing process. The project development timeline is presented in Figure 23.[86]

Figure 23: PNGTS Project Development Timeline

PNGTS presented three options to its primary proposal. Two of these three options would originate at Dawn, Ontario or Niagara/Chippewa, [redacted] PNGTS also offered an option for [redacted]

Although PNGTS is directly connected to certain generation, approximately 57 percent of

[85] http://www.transcanada.com/news-releases-article.html?id=1703748, accessed November 13, 2015.
[86] http://www.northeastgas.org/pdf/c_armstrong_2014.pdf, accessed November 13, 2015.

the directly connected natural gas-fired and dual-fuel generation is on Algonquin and approximately 24 percent is on Tennessee. As such, shippers on PNGTS would need to incur incremental cost to secure downstream transportation on Algonquin and Tennessee to connect to these facilities.

In its proposed path, the PNGTS Expansion project would rely on three existing pipelines (i.e., Iroquois, TCPL, and PNGTS) to transport up to [redacted] from Wright, NY to Waddington, NY on Iroquois. From Waddington, natural gas would be transported east on the TCPL system to Pittsburg, NH. From Pittsburg, NH, natural gas would be transported southeasterly to Westbrook, ME on the PNGTS pipeline, and then transported southwesterly from Westbrook, ME to Dracut, MA on the Joint Facilities. To reach Algonquin and Tennessee power generation facilities, additional capacity would be required on the respective pipelines.

The minimum term for the PNGTS Expansion project is 20 years for the primary path from Wright, NY to Dracut, MA, and the PNGTS Expansion is slated to commence service in November 2019.

As discussed, this transportation path primarily relies on pipelines in New York and Canada to deliver natural gas into New England. Notably, the PNGTS Expansion project relies on the TCPL project to deliver natural gas to Pittsburg, NH. Although TCPL committed to obtaining the requisite approvals, the currently approved TCPL tariff does not provide for long-term (i.e., greater than 5 years) agreements for fixed tolling arrangements.

The PNGTS proposal also gives rise to unique attributes not present in the proposals of the other bidders, including: currency risk, an additional regulatory jurisdiction (i.e., the NEB, as well as FERC), and path/contract complexity.

Q. Please provide an overview of the Repsol LNG proposal.

A. The Repsol proposal offered to supply up to [redacted] and [redacted] of LNG imported to North America via the Canaport LNG facility located in St. John, New Brunswick, and delivered to New England via the Brunswick Pipeline and M&NP. Repsol offered to provide these services for a term of 18 years, at a reservation charge equal to [redacted]

Repsol holds rights to 100 percent of the capacity of the Canaport LNG facility, which is jointly owned with Irving Oil Ltd. In addition to the Canaport LNG facility, Repsol holds [redacted] of firm transportation capacity on the Brunswick Pipeline and [redacted] of firm transportation capacity on M&NP with certain volume deliveries to Dracut, MA and Beverly, MA. The Repsol proposal provided for year-round reservation of this transportation capacity the EDCs.

Similar to the PNGTS proposal, the Repsol bid would directly connect to a limited number of natural gas-fired and dual-fuel power generators. Therefore, to reach the power generation directly connected to Algonquin and Tennessee, downstream transportation is required on these pipelines. Therefore, and similar to PNGTS, the Repsol proposal requires downstream transportation on AGT and TGP to serve the natural gas-fired and dual-fuel power plants located on the respective pipelines.

The Repsol proposal did not identify the source of the LNG.

Q. Please provide an overview of the GDF SUEZ LNG proposal.

The GDF SUEZ proposal included three options to supply up to [redacted] of imported LNG via the GDF SUEZ Everett LNG and/or Neptune LNG.[87] As outlined by GDF SUEZ, re-gasified LNG would be delivered from the GDF SUEZ Everett LNG to the Tennessee and Algonquin transmission systems for downstream delivery to New England power generators.

The Daily Call service would provide for the right to call up to [redacted] The proposal included [redacted]

The Vapor Peaking service would provide [redacted]

[87] [redacted]

[redacted] The term of the agreement was for 15 years, commencing on December 1, 2017.

Lastly, the Base Load Supply service would provide [redacted]

To source its LNG, GDF SUEZ noted that it relies on several global LNG supply sources, as summarized in Table 8.

[88] While the five-year minimum term is less than the minimum term required by the RFP, Sussex permitted the offer to proceed through the screening phase due to GDF SUEZ noting its willingness to consider longer terms.

Table 8: GDF SUEZ Sources of LNG

Country/Supplier	Supply (Bcf/Yr)	% of Total (Pre-2018)	% of Total (2018-2020)	% of Total (Post-2021)
[redacted]				

As shown in Table 8 above, [redacted]

Q. Please describe the Access Northeast project.

A. The Access Northeast project is sponsored by affiliates of Spectra Energy, Eversource Energy and National Grid. The project will deliver 900,000 MMBtu/day of incremental natural gas supply (500,000 MMBtu/day of incremental pipeline capacity and 400,000 MMBtu/day of LNG deliverability) over four project phases via the expansion of 125 miles of the existing Algonquin system. The majority of the construction will be within the existing rights-of-way of the Algonquin system. In addition, the project will include the construction of a new LNG facility in Acushnet, MA, which will be co-located with an existing Eversource Energy satellite LNG facility. The new LNG facility will have 400,000 MMBtu/day of vaporization capacity, 54,000 MMBtu/day of liquefaction capacity, and two LNG storage tanks each with a capacity of 3.4 Bcf. The total estimated construction cost for the Access Northeast project is approximately $3.2 billion.

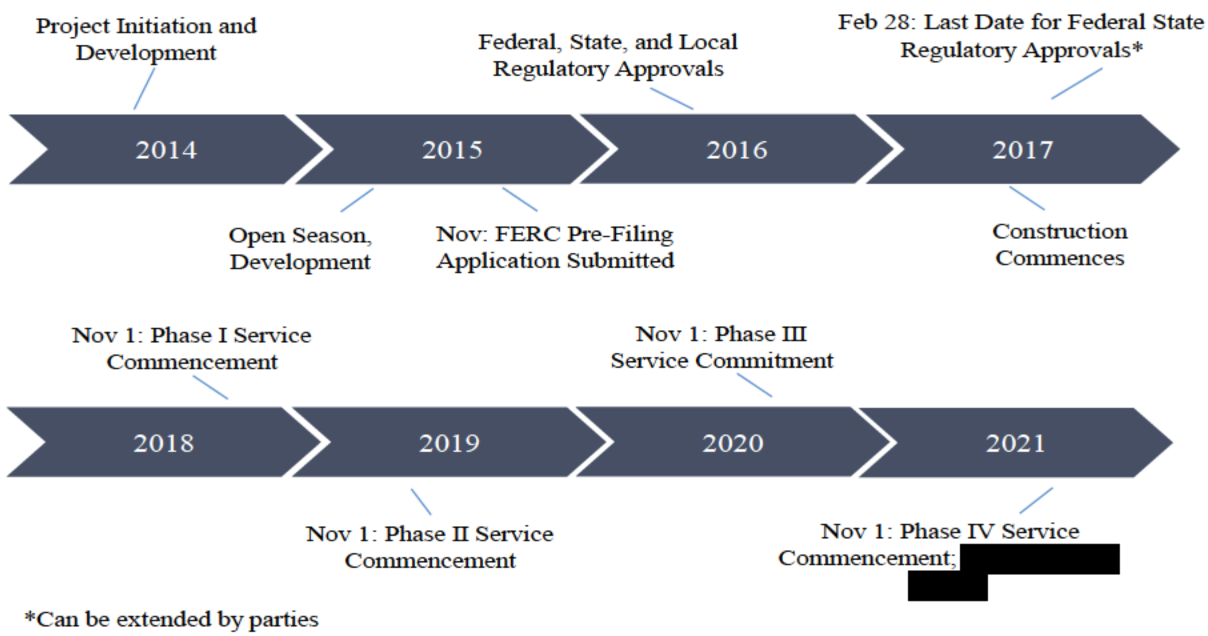
The Access Northeast project will include multiple receipt points along the Algonquin system, which will permit southern New England shippers to transport natural gas from various interconnection points between Algonquin and certain upstream pipeline companies for deliveries in Connecticut, Massachusetts, and Rhode Island. Similarly, Access Northeast will permit northern New England shippers to transport natural gas to M&NP-U.S. for deliveries into New Hampshire and Maine.

To serve the power generation segment, Access Northeast will offer an Electric Reliability Service rate schedule, which is designed to provide additional flexibility for the power generation segment when nominating natural gas deliveries. In addition, the capacity mitigation options associated with the proposed route are expected to provide additional value due to the proximity to load.

The sponsors of the Access Northeast project recently submitted a request to initiate the FERC's pre-filing review process. The Access Northeast sponsors expect to file a full application for a FERC CPCN in 2016. Phase I of the Access Northeast project is expected to enter service in 2018, with each successive phase entering service one year later than the previous phase (i.e., Phase II in 2019, Phase III in 2020, and Phase IV in

2021). Figure 24 illustrates the expected Access Northeast development timeline.

Figure 24: Access Northeast Development Timeline



V. <u>Evaluation of the Proposals</u>

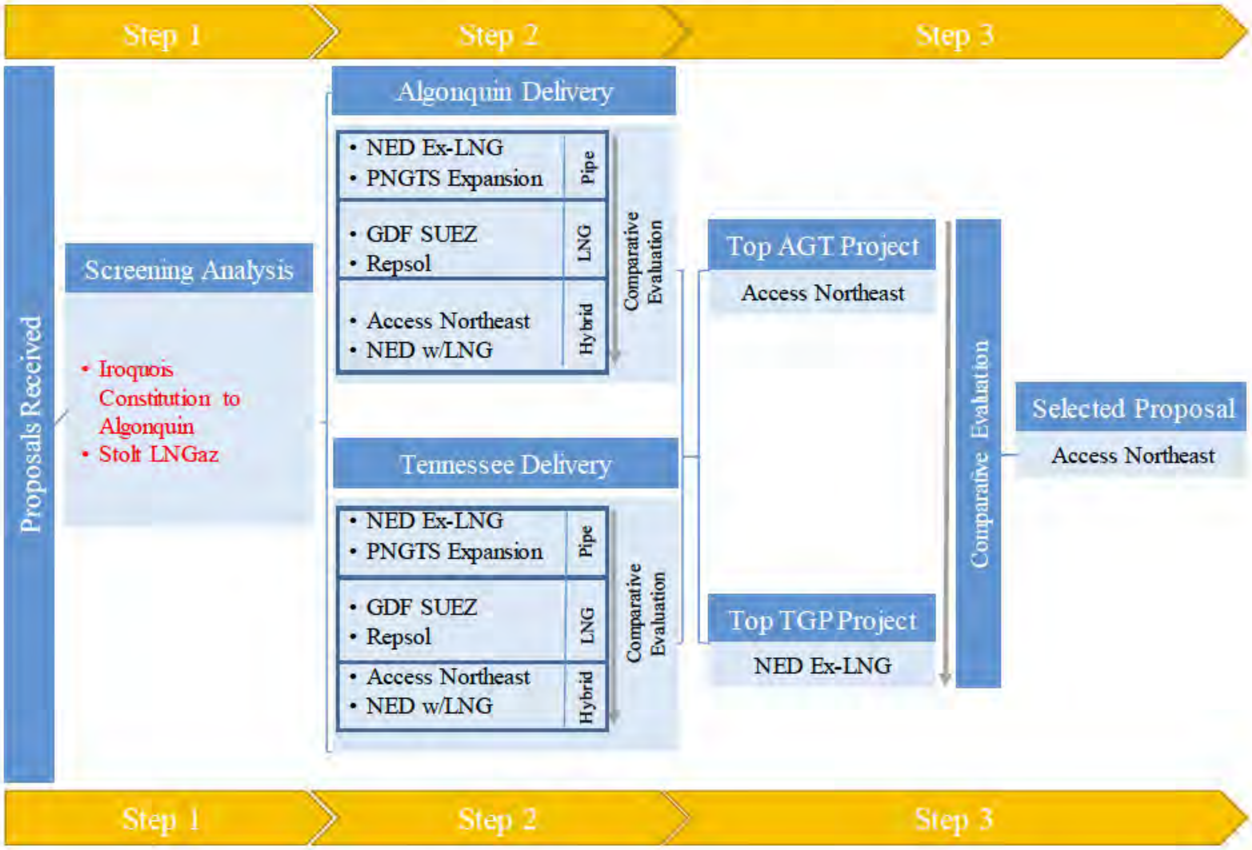
Q. What were the results of the RFP and the competitive solicitation process?

A. The ultimate result of the RFP was the selection of the Access Northeast project as the resource alternative with the most capability to have an impact on the wholesale electric price concerns existing for Eversource's retail electric customers. As described in greater detail below, the Access Northeast project presented the lowest forecasted delivered cost to natural-gas fired capacity on Algonquin. Therefore, the proposed Access Northeast project has substantial market reach (i.e., nearly 70 percent of directly connected natural gas-fired and dual-fuel power plants) and reasonable cost relative to the competing proposals. In addition, the Access Northeast project presented the flexibility necessary to support power generators by rapidly responding to the demands of ISO-NE, while providing delivery area flexibility to ensure the capacity can be utilized by a wide breadth of power generators. Lastly, the Access Northeast project is sponsored by entities that have long-term experience constructing, owning, operating, and expanding natural gas pipelines in New England. Notably, Algonquin and its owners are currently expanding the Algonquin system through the AIM project and are proposing to further expand the Algonquin and M&NP pipelines via the Atlantic Bridge project. The experience gained through those projects will considerably aid the development and construction of the Access Northeast project.

Q. Please describe the evaluation process utilized by Sussex to select the optimal resource alternative.

A. The evaluation process utilized by Sussex is illustrated in Figure 25. The Sussex evaluation process consisted of three steps: (i) a high-level screening analysis, (ii) a qualitative and quantitative evaluation that identified the top proposals to deliver natural gas to Algonquin and Tennessee, and (iii) a comparative evaluation between the Algonquin and Tennessee proposals.

Figure 25: Sussex Evaluation Process



This stepwise evaluation process provided an objective framework for organizing the various analyses developed by Sussex.

Q. Please describe the screening analysis that was performed by Sussex in Step 1 of the evaluation process.

A. To begin our evaluation, Sussex reviewed the proposals received in response to the RFP to determine if the responses conformed, at a high level, with the requirements and objectives of the RFP. Table 9, below, identifies the specific proposals that were eliminated during this initial screening process. Each of the proposals below did not meet the threshold outlined in the RFP.

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Table 9: Results of Sussex Screening Analysis

Proponent	Proposal Description	Non-Conformance
Iroquois	(1) Constitution Pipeline to Algonquin	[redacted]
Stolt LNGaz	(1) LNG Supply via barge or truck to New England	[redacted]

As identified in Table 9, the Stolt LNGaz proposal did not pass the initial screen [redacted] The Iroquois proposal [redacted]

Q. After the initial screening was completed, please describe the next step in the Sussex evaluation process.

A. In the second step of the Sussex evaluation process, the proposals that passed the initial screen were evaluated based on their ability and associated cost to deliver supply to natural gas-fired and dual-fuel power generation directly connected to Algonquin and Tennessee. Algonquin and Tennessee were selected because Algonquin represents approximately 57 percent of the directly connected natural gas-fired and dual-fuel generation capacity and Tennessee represents the second largest share at approximately 24 percent. When combined, these two pipelines represent approximately 80 percent of

[redacted]

the natural gas-fired generation directly connected to an interstate pipeline in the ISO-NE region.

Q. Did Sussex further organize the proposals received in response to the RFP?

A. Yes. Sussex classified the bids as either Pipeline Only, Imported LNG, or Hybrid proposals to reflect the similarities of certain bid structures. The Pipeline Only classification consisted of two proponents that included only incremental pipeline capacity options: (i) the Tennessee NED project; and (ii) the PNGTS Expansion project.

The Imported LNG classification consisted of the GDF SUEZ and Repsol proposals.

The Hybrid classification consisted of incremental pipeline capacity and market area LNG storage options and included proposals by two proponents: (i) the Access Northeast project; and (ii) the Tennessee NED project.

Q. After the proposals were organized, what was the next step in the Sussex evaluation process?

A. Once the proposals were organized, Sussex developed a quantitative assessment of each of the proposals. For each proposal, the quantitative analysis consisted of an estimate of the "landed cost" to deliver natural gas supplies to Algonquin or Tennessee. Since each of the classifications (i.e., Pipeline Only, Hybrid, and Imported LNG) included similar terms and conditions and pricing structures, the classification of the bids allowed for the comparison of bids within and across classifications.

Q. Please outline the components of a landed cost analysis.

A. In general, a landed cost analysis assumes that pipeline demand charges are priced at a

100 percent load factor (i.e., the transportation path is used every day at full volume) and gas supply cost, variable, and/or fuel charges are added to the unitized demand charge. This approach allows for the comparison of different paths in a simple, transparent manner.

As shown in Table 10, a landed cost analysis typically includes five steps. First, the potential paths for the delivery of a natural gas supply to a specified delivery point are identified and mapped. Second, the source of the natural gas supply (e.g., supply basin or market hub) for each of the identified paths is developed, and third, the cost of the natural gas supply from the specific basin or market hub is calculated and can be presented as a basis differential to a base price (e.g., a price premium or discount to Henry Hub). The penultimate step is to calculate the unit transportation and/or LNG facility cost (i.e., demand, variable, and fuel charges) for all the infrastructure that supports the path. Lastly, the landed cost for each path is totaled (i.e., the gas supply cost plus the per unit total infrastructure costs).

Table 10: Landed Cost Methodology

1	2	3	4		5 = 3+4
Path	**Gas Supply**	**Gas Supply Cost**	**Pipeline 1**	**Pipeline 2**	**Total**
A	Market Hub	Henry Hub - X	$R	N/A	Henry Hub - X + $R = Path A Total
B	Supply Basin	Henry Hub + Y	$S	$T	Henry Hub + Y + $S + $T = Path B Total

For example, as demonstrated in Table 10 above, Path A consists of a Market Hub gas supply, which is priced at Henry Hub minus a basis differential of “X” and is transported on Pipeline 1 for a total landed cost comprised of the gas supply cost (i.e., “Henry Hub -

X") and the transportation cost for Pipeline 1 (i.e., "$R"). Similarly, Path B consists of a Supply Basin gas supply transported on both Pipeline 1 and Pipeline 2 for a landed cost comprised of the gas supply cost (i.e., "Henry Hub + Y") plus total transport cost on Pipeline 1 and Pipeline 2 (i.e., "$S + $T").

Q. Although each of the bid classifications have unique commercial structures, were common assumptions used to evaluate all the proposals?

A. Yes, there were certain common assumptions used to evaluate all the proposals. Specifically, the underlying gas supply cost was developed in a similar manner for all the proposals; and two natural gas price sensitivities were used to evaluate the proposals. Sussex used the Henry Hub forward price as the base gas supply cost; and basis premiums or discounts for the various gas supply points were developed as differentials to the Henry Hub price. Two natural gas price sensitivities were also considered to evaluate each proposal including:

- The Henry Hub prices and basis differentials for the 2016/2017 – 2021/2022 split years; and
- The Henry Hub prices and basis differentials for the 2016/2017 – 2021/2022 winter periods.[92]

Q. Please discuss the assumptions used by Sussex regarding the transport cost on Tennessee and Algonquin for third-party proposals, which required delivery on these pipelines.

A. The delivery charges on Algonquin for deliveries from upstream pipelines were based on information provided by Algonquin; and the delivery charges on Tennessee for deliveries

[92] Sussex used a simple average of the settlement prices for the seven trading days from December 1 through December 10, 2015.

from upstream pipelines were based on information provided by Tennessee. These rates were used in the landed cost analysis to estimate the delivered costs for proposals that provided service to Tennessee or Algonquin. It is important to note that the in-service date for any incremental facilities would typically be implemented after resolution of any existing projects that are currently under development.

Q. Please describe the commercial structures for the Pipeline Only classification that were used in the landed cost analysis.

A. In addition to the gas supply cost, the landed cost analysis for the pipeline options included the demand, variable, and fuel rates on all the pipelines in the transportation path.[93]

Q. Please describe the commercial structures for the Hybrid classification that were used in the landed cost analysis.

A. In addition to the gas supply cost and the pipeline delivery cost, the landed cost analysis for the Hybrid options included the LNG storage component outlined in the specific bids. As such, the LNG fixed charges were included with the pipeline demand charges; and LNG variable costs were developed.

Q. Please describe the deal and structure components for the Imported LNG classification that were used in the landed cost analysis?

A. The landed cost analysis for the Imported LNG options included the gas supply costs, the pipeline delivery cost, and the cost for the LNG offered in the proposal. To develop the

93 The Tennessee NED project options included in the Pipeline classification offered Marcellus and Wright, NY receipt points and Dracut, MA and Mendon, MA delivery points. For those delivery paths to Algonquin that relied on the Marcellus receipt point or the Dracut delivery point Sussex used weighted averages for the volume of natural gas available to be purchased at the Marcellus index. Sussex did not consider delivery paths to Tennessee that relied on the Dracut, MA delivery point as there are few power generators that could be served from Dracut without incurring an additional cost.

unit cost for the Imported LNG bids the Annual Contract Quantity ("ACQ") was used as the available quantity to unitize the annual demand costs. For example, if the demand cost for the LNG contract was $1 for 1,000 MMBtu per day of withdrawal capacity and the LNG ACQ was equal to 30,000 MMBtu, the unitized demand charge would equal ($1 * 1,000 MMBtu *365) / 30,000 MMBtus) for a unit demand cost of $12.16/MMBtu.

Q. Please discuss the landed cost analysis results for deliveries to the AGT.

A. As illustrated by Table 11, the Access Northeast project was the most competitive option for natural gas deliveries to power plants directly connected to the Algonquin system. Additional details from the AGT Landed Cost Analysis can be found in Attachment EVER-JMS-4 [CONFIDENTIAL], Pages 1-2.

Table 11: AGT Landed Cost Summary – Top Proposal from Each Proponent

				Path Rank by Sensitivity		Annual 2016/2017-2021/2022	
Proposal Name	Bid Classification	Gas Supply Point	Delivery Area	Annual 2016/2017-2021/2022 Forwards	Winter 2016/2017-2021/2022 Forwards	Total Fixed Charges	Total Fixed Charges Rank
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	1	1	[redacted]	5
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	3	3	[redacted]	9
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	7	7	[redacted]	11
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	4	5	[redacted]	12
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	5	4	[redacted]	8
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	2	2	[redacted]	10
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	6	6	[redacted]	7
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	11	11	[redacted]	4
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	9	9	[redacted]	3
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	12	12	[redacted]	1
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	10	10	[redacted]	2
[redacted]	[redacted]	[redacted]	AGT (7,039 MW)	8	8	[redacted]	6

Q. Please discuss the landed cost analysis results for deliveries to Tennessee.

A. As illustrated by Table 12, the Tennessee NED project is the most competitive bid for natural gas deliveries to power plants directly connected to the TGP system. Additional details from the TGP Landed Cost Analysis can be found in Attachment EVER-JMS-4 [CONFIDENTIAL], Pages 3-4.

Table 12: TGP Landed Cost Summary – Top Proposal from Each Proponent

Proposal Name	Bid Classification	Gas Supply Point	Delivery Area	Path Rank by Sensitivity: Annual 2016/2017-2021/2022 Forwards	Path Rank by Sensitivity: Winter 2016/2017-2021/2022 Forwards	Annual 2016/2017-2021/2022: Total Fixed Charges	Annual 2016/2017-2021/2022: Total Fixed Charges Rank
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	6	6	[redacted]	11
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	7	9	[redacted]	12
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	4	4	[redacted]	4
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	2	2	[redacted]	10
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	3	3	[redacted]	2
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	1	1	[redacted]	8
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	5	5	[redacted]	9
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	11	11	[redacted]	6
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	9	8	[redacted]	5
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	12	12	[redacted]	1
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	10	10	[redacted]	3
[redacted]	[redacted]	[redacted]	TGP (3,014 MW)	8		[redacted]	7

Q. Is a Landed Cost Analysis the only consideration when selecting a natural gas supply resource?

A. No. Typically, a landed cost analysis is one component of a natural gas capacity or resource decision-making process. In addition, the decision will likely be informed by other evaluation metrics including, the qualitative attributes of each option, the expected impact of the resource decision, and other factors, such as timing of the project. Stated differently, the landed cost analysis, while used to inform the decision, is only part of a more fulsome analysis process. With respect to the Eversource decision to contract on the Access Northeast project, the competitiveness of the Access Northeast project in the landed cost analysis is coupled with the qualitative assessment results and the cost benefit analysis. I address the qualitative attributes of the various projects below, while Company Witness Mr. Kevin Petak addresses the net-benefit analysis of the Access Northeast project. All these analyses, integrated with the substantial analysis, expertise, and experience of Eversource and its advisors inform the decision to contract on the Access Northeast project.

Q. Do you have any other observations related to the landed cost analysis performed by Sussex?

A. Yes, I do. There are two important considerations related to the Sussex landed cost analysis: (i) the power generating capacity that can be served on each path, and (ii) the balancing of the estimated landed cost with the fixed cost obligation created by a specific proposal.

First, the Sussex landed cost analysis estimates the unitized cost of delivering natural gas to Algonquin and Tennessee using the information provided in each proposal, indicative rates from Algonquin and Tennessee, and certain public information. The analysis is inherently unit cost-focused and does not directly consider the power generating capacity that can be served from each pipeline (i.e., Algonquin or Tennessee). For example, and as shown on Figure 18, transportation paths that deliver to Algonquin have access to 7,039 MW of generating capacity. In contrast, transportation paths that deliver to Tennessee have access to 3,014 MW of generating capacity. Stated differently, a project that delivers natural gas to Algonquin has direct access to approximately two times the natural gas-fired and dual fuel generation than a project that delivers to Tennessee.

Second, it is important to balance the estimated landed cost with the level of fixed charges associated with each path as these costs must be incurred regardless of whether natural gas is being transported on the path. Although a path may be low cost on the landed cost analysis, it may not represent the best option for customers given a large fixed charge obligation. For instance, and as shown in Table 11 above, the Access Northeast project is ranked number 1 (i.e., lowest landed cost) for deliveries on Algonquin, while the Tennessee NED project without LNG with receipts at TGP Z4 is ranked number 2; however, the fixed cost obligation on the Tennessee NED project without LNG requires an additional [redacted] per year in fixed charges over the Access Northeast project.

As shown in Table 12, the Tennessee NED without LNG with receipts at TGP Z4 project is ranked number 1 for deliveries on Tennessee; however, the fixed cost obligation of approximately [redacted] is [redacted] per year higher than the Access Northeast project. In addition, the Access Northeast project has [redacted] more deliverability to serve approximately two times the generating capacity as the Tennessee NED project without LNG.

Conversely, it may not be in customer interest to select the lowest fixed-charge cost without balancing the expected landed cost. For instance, the imported LNG paths represent five of the six paths with the lowest fixed charges to deliver natural gas to Algonquin, but also present the highest expected landed cost as a result of the higher commodity charges and the limited ACQs.

Q. What qualitative evaluations were undertaken by Sussex during the second stage of the evaluation process?

A. During the second stage of the proposal evaluation process, Sussex conducted high-level reviews of certain qualitative metrics of each of the proposals. At this phase of the evaluation, Sussex was specifically identifying notable risks or challenges that would inhibit the proposal or its sponsor from meeting the objectives of the RFP (i.e., the ability to mitigate high wholesale power and natural gas prices) or that would cause Eversource and its customers to bear unnecessary risks associated with the fixed cost of the projects.

The specific topics reviewed are shown in Table 13.

Table 13: Qualitative Evaluation Criteria

Qualitative Evaluation Criteria	
A. The financial condition of the Project Sponsors,	B. Status of local, state, and federal approval processes and planning,
C. New England development and operating experience,	D. Supply risk related to the upstream capacity connections and supply sources,
E. Renewal terms,	F. Service flexibility, and
G. Construction risks related to schedule,	H. Potential capacity mitigation opportunities.

Table 14 summarizes the qualitative evaluation in each of these categories. By way of example, if a proposal received a ✓+ in the Service Flexibility Category, that proposal offered the highest service flexibility relative to the other proposals.

Additional discussions related to each of categories can be found in Attachment EVER-JMS-5 [CONFIDENTIAL] through Attachment EVER-JMS-7 [CONFIDENTIAL].

Table 14: Qualitative Evaluation Summary

	Category	Pipeline		Imported LNG		Hybrid	
		NED Ex-LNG	PNGTS Expansion	GDF Suez	Repsol	Access Northeast	NED w/LNG
Sponsor	Sponsor Financial Condition	[redacted]					
	Fixed Price						
	Regional Development, Construction, and Operating Experience						
Project	Serves Power Generation						
	Incremental Deliverability						
	Upstream Supply and Price Liquidity						
	Service Flexibility						
	Capacity Mitigation Opportunities						
	Accepted Renewal Terms						
Develop-ment	Construction Risks						
	Approvals Underway/Planned						

The principle qualitative differences that influenced the outcome of the RFP evaluation process were related to the share of the natural gas and dual-fuel power generation market directly served by each proposal; the service flexibility provided; the upstream supply availability; and price liquidity.

All the proposals were capable of directly serving certain levels of the power generation market; however, the Access Northeast and NED projects offered direct “last-mile” capacity to substantially more generating capacity than the remaining proposals. Stated differently, the Access Northeast and NED proposals provide direct downstream connectivity to approximately 80 percent of directly connected natural gas-fired and dual-fuel generators, whereas the remaining proposal would have required incremental downstream connectivity in order to serve the majority of New England natural gas-fired generators.

All of the proposals provide some level of service flexibility through no or limited notice services, but the flexibility offered by the Access Northeast and NED Project with LNG were distinguished from the remaining proposals. More specifically, the Access Northeast and NED Project with LNG proposed rate structures with inherent delivery point flexibility, supply for no notice service for "fast start" generating facilities and priority capacity rights to support the assignment of capacity from the EDCs to New England power generators.

Lastly, the adequacy of the upstream supply further distinguished certain of the proposals. Specifically, the Access Northeast, NED, and PNGTS Expansion projects all rely on North American-sourced gas supplies. All of the options proposed by these bidders would also provide access to the Marcellus and Utica shale basins, which, as discussed in the Market Context Section (i.e., Section III) is a prolific, low cost gas supply source. Conversely, the supply resources for the imported LNG proposals rely on LNG from international locations. As such, the supply availability is subject to the political, commercial, and regulatory environment in each of the exporting countries.

In addition to the adequacy of supply, Sussex also considered the liquidity of the index proposed by the bidders. For this assessment, Sussex relied on a methodology used by Platts to categorize natural gas pricing points into one of three liquidity tiers based on the volumes traded and the number of transactions at each pricing point. Each tier is defined as follows:

- Tier 1 – Points with traded volumes of at least 100,000 MMBtu/day and/or at least 10 trades per day;
- Tier 2 – Points with traded volumes of 25,000 to 99,999 MMBtu/day and/or at least five trades per day; and
- Tier 3 – Points with traded volumes below 25,000 MMBtu/day and/or fewer than five trades per day.[94]

The primary paths for both the NED project and PNGTS Expansion proposals rely on Wright, NY as a primary receipt point, while the Access Northeast project relies on Ramapo, NY or the TETCO M-3 price index. As discussed previously, Wright, NY is not currently a recognized natural gas pricing point; therefore, Sussex relied on the Iroquois Zone 2 pricing index as a reasonable proxy for the Wright, NY point.[95]

Similarly, Tennessee proposed options with alternative receipt points. Therefore, Sussex evaluated the price liquidity for those alternative receipt points by reviewing the liquidity of the Tennessee Z4 300 Leg Price point as a proxy for the Tennessee Z4 Marcellus price point for the NED Tennessee Z4 receipt point. As illustrated by Table 15, the TETCO M3 pricing point is rated as a Tier 1; while the remaining supply points are generally Tier 2 pricing points.

[94] Platts, "Methodology and Specifications Guide – North American Natural Gas," October 2015 update, at 5.
[95] The Iroquois Zone 2 pricing index is utilized by the NY ISO Market Monitor for the zone that includes Wright, NY.

Table 15: Receipt Point Liquidity

	Henry Hub			TETCO M3			Iroquois Zone 2 (Wright Proxy)		
Split-Year (Nov-Oct)	Avg. Daily Volume (000 MMBtu)	Avg. No. of Deals	Avg. Tier	Avg. Daily Volume (000 MMBtu)	Avg. No. of Deals	Avg. Tier	Avg. Daily Volume (000 MMBtu)	Avg. No. of Deals	Avg. Tier
2009/2010	278	21	1	439	72	1	71	12	2
2010/2011	168	12	2	385	60	1	97	15	2
2011/2012	248	14	2	453	67	1	54	13	2
2012/2013	190	14	1	367	62	1	79	18	2
2013/2014	171	11	2	358	76	1	42	9	2
2014/2015	136	11	2	285	62	1	30	9	2

	TGP Z4 300 Leg		
Split-Year (Nov-Oct)	Avg. Daily Volume (000 MMBtu)	Avg. No. of Deals	Avg. Tier
2009/2010	N/A	N/A	N/A
2010/2011	N/A	N/A	N/A
2011/2012	N/A	N/A	N/A
2012/2013	104	17	2
2013/2014	119	19	2
2014/2015	106	27	2

* 2014/2015 data through August 2015.

Q. Did any of the remaining qualitative criteria distinguish the proposals received in response to the RFP?

A. All of the proposals that require new facilities were assumed to be constructible. Nonetheless, the NED project without LNG presented certain risks that made it more likely relative to the alternative proposals to experience schedule delays that would affect the availability of the project. For example, the NED project without LNG consists of greenfield construction in Pennsylvania, New York, Massachusetts, and New Hampshire that could be delayed due to public opposition. In addition, the NED project with LNG included the possibility of market area LNG storage, but did not specify a specific site for the LNG storage facility, which could affect the achievement of the proposed in-service date for that option.

Q. Please describe the qualitative evaluation performed by Sussex in the final step of the evaluation process.

A. Once the top proposals for Algonquin and Tennessee were identified, Sussex compared the qualitative attributes of the selected proposal to determine the proposal that was most likely to address the persistently high wholesale power and natural gas prices. That comparative evaluation is presented in Attachment EVER-JMS-8 [CONFIDENTIAL] and is summarized in Table 16 below.

Table 16: Step 3 Qualitative Comparative Evaluation

Project Name	Relative Qualitative Evaluation							
	Winter Generating Capacity Served	Peak Day Deliverability	Fixed Demand Charges	Flexibility	Receipt Point Liquidity	Construction Risks	Sponsor Financial Condition	Capacity Mitigation Opporunities
Access Northeast	[redacted]							
NED Ex-LNG TGP Z4 Receipts								

As shown above, based on the comparative evaluation, the Access Northeast project provides the better qualitative results relative to the Tennessee NED project without LNG with receipts at TGP Z4 proposal in the categories of winter generating capacity served, peak day deliverability, flexibility of the project, receipt point liquidity, construction risk, and sponsor financial condition. The Access Northeast project was equivalently ranked with respect to the likely capacity mitigation opportunities offered by the project.

Q. How did Sussex determine the optimal overall resource alternative for Eversource?

A. The optimal overall proposal was determined by combining the qualitative and quantitative analysis. Table 17 below summarizes both analyses and shows that Access Northeast has the combination of attributes representing the largest market reach and highest capability to impact and wholesale market prices.

Table 17: Evaluation Summary

Project Name	Landed Cost Rank	
	Annual 2016/2017-2021/2022 Forwards	Winter 2016/2017-2021/2022 Forwards
Access Northeast	[redacted]	
NED Ex-LNG TGP Z4 Receipts		

Project Name	Relative Qualitative Evaluation							
	Winter Generating Capacity Served	Peak Day Deliverability	Fixed Demand Charges	Flexibility	Receipt Point Liquidity	Construction Risks	Sponsor Financial Condition	Capacity Mitigation Opportunities
Access Northeast	[redacted]							
NED Ex-LNG TGP Z4 Receipts								

In short, the Access Northeast project presented the lowest landed cost to generation directly connected to AGT, and provided access to the largest quantity of natural gas-fired generation.

VI. Overview of the Proposed ANE Contract

Q. Please describe the proposed ANE Contract that Eversource has executed with Algonquin to secure capacity on the Access Northeast project.

A. Eversource executed a precedent agreement with Algonquin for service on the Access Northeast project on February 15, 2016. As discussed in the Direct Testimony of Mr. James Daly, the ANE Contract executed by Eversource are identical to the ANE Contracts executed by the Eversource EDCs, but for the naming of the respective EDC, the various maximum daily quantities and obligations as defined below, the inclusion of the applicable rate schedule, and a map of the Aggregation Areas as attachments.

Pursuant to the proposed ANE Contract, service on the Access Northeast project will be provided under a new rate schedule known as the Energy Reliability Service ("ERS"). The ERS rate schedule combines attributes of firm transmission, no-notice service, and high-deliverability storage to provide additional service flexibility to power generators. In addition, pending FERC approval, the ERS rate schedule will include priority capacity assignment rights to ensure the released capacity is made available to New England power generators. A more detailed review of the ERS rate schedule and the ANE Contract is provided in the testimony of Company Witness James G. Daly.

The primary terms and conditions of the ANE Contract include:

Term – The ANE Contract specifies that the parties will execute firm transportation service agreements with primary terms extending 20 years from the Phase 1 Service

Commencement Date, which is currently expected to occur in November 2018.[96] [redacted]

<u>Reservation Rate</u> – [redacted]

<u>MDTQ</u> – The MDTQ is 66,600 MMBtu/day.[99] This is the maximum daily amounts of natural gas that may be transported on the pipeline component of the Access Northeast project on behalf of Eversource. The MDTQ was determined by the product of Eversource's share of the total electric load served by investor owned utilities in New England ("EDC Share") and the transportation quantity of the Access Northeast project allocated to EDCs.

<u>Maximum Daily Receipt Obligation ("MDRO")</u> –The MDRO is allocated across three

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[96] The ANE Contract at 6, 11.
[97] Ibid., at Attachment C: Negotiated Rate Agreement.
[98] Ibid., at Attachment C: Negotiated Rate Agreement, Footnote 3.
[99] Ibid., Attachment C: Negotiated Rate Agreement.

receipt points, and is summarized in Table 18 for Eversource.

Table 18: Access Northeast Receipt Points – MDRO (MMBtu/day)[100]

MMBtu/day Receipt Point	Eversource
Mahwah, NJ	37,000
Ramapo, NY	37,000
Brookfield, CT	27,010

Maximum Daily Delivery Obligation ("MDDO") – The MDDO for each Aggregation Area is determined by the EDC Share and the amount of capacity assigned to each Aggregation Area. Table 19 provides the MDDO by Aggregation Area for Eversource.

Table 19: Access Northeast Delivery Points – MDDO (MMBtu/day)[101]

Aggregation Area	Eversource
Connecticut AA	28,120
SEMA – AA	5,920
Massachusetts AA	26,640
Maine AA	5,920

MSQ – The MSQ is 473,600 MMBtu.[102] The MSQ represent the maximum amount of LNG that can be held in storage on behalf of the Company.

Maximum Daily Injection Quantity ("MDIQ") – The MDIQ is 3,996 MMBtu per day. The MDIQ represents the maximum quantity of natural gas that may be injected into the

100 Ibid., at 6.
101 Ibid., at 6-7.
102 Ibid., at 6.

LNG storage on a given day for the Company.[103]

MDWQ – The ANE Contract specifies a MDWQ of 29,600 MMBtu per day.[104] The MDWQ represents the maximum quantity of natural gas that can be withdrawn from LNG storage on a given day by the Company.

MFN Status – Eversource has negotiated for MFN status, which will provide Eversource with assurance that it will obtain the lowest cost service relative to other counterparties pursuing similar transportation and storage services. [redacted][105]

Q. What risk and risk mitigation strategies are related to the ANE Contract?

A. Although certain risks related to the Access Northeast project were identified, the primary risks are largely mitigated through: (i) provisions in the ANE Contract; (ii) the type of service provided; (iii) the type of demand served by the ANE Contract; (iv) the supply basins from which natural gas is likely to be sourced; and (v) the strength of the project sponsors.

Q. Does Spectra Energy Partners, LP ("Spectra") have sufficient experience operating natural gas transportation assets in New England?

A. Yes, it does. As discussed in Attachment EVER-JMS-3, Algonquin operates a system of 1,129 miles of pipeline in Connecticut, Massachusetts, New York, New Jersey, and Rhode Island. Algonquin has been in operation since 1949, and is 100 percent owned by

[103] Ibid., at 7.
[104] Ibid., at 6.
[105] Ibid., at Attachment C: Negotiated Rate Agreement, Footnote 8.

Spectra and operated by Spectra Energy Corporation.[106] In aggregate, Algonquin transports 2.74 Bcf/day from the Texas Eastern Transmission, LP system to the M&NP pipelines both of which are owned fully and partially by Spectra, respectively.[107]

Spectra has a Baa2 credit rating from Moody's and a BBB rating from both S&P and Fitch Ratings. Spectra has a total enterprise value of $20.6 billion.[108] Inclusive of its ownership of Algonquin, Spectra operates a network of over 22,000 miles of natural gas, natural gas liquids, and crude oil pipelines; 300 Bcf of natural gas storage and 4.8 million barrels of crude oil storage.[109] Additionally, Spectra owns and operates Union Gas Limited, a natural gas distribution company with operations in Ontario, including the Dawn Hub.[110]

Lastly, the approach to the construction of the pipeline component of Access Northeast is similar to the construction now being used by Algonquin for the AIM Project, thus increasing Algonquin's "in-corridor" construction experience.

VII. Summary and Conclusions

Q. What is your conclusion regarding the ANE Contract?

A. The ANE Contract resulted in the procurement of a reasonable and viable solution to enhance gas supply deliverability and to address the high wholesale natural gas and

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106 www.bloomberg.com/research/stocks/private/snapshot.asp?privcapid=4258626, accessed 11/11/2015.
107 www.spectraenergy.com/Operations/US-Natural-Gas-Pipelines/Algonquin-Gas-Transmission, accessed 11/11/2015.
108 SNL Financial.
109 Spectra Energy Factsheet, accessed November 12, 2015.
110 Ibid.

power prices recently experienced in New England. The Access Northeast project is expected to provide 500,000 MMBtu/day of incremental natural gas transportation capacity into New England and an even greater volume (i.e., 900,000 MMBtu/day) of natural gas deliverability during the peak winter and summer months. As discussed by Company Witness James G. Daly, the LNG storage component of the Access Northeast project will provide flexibility to meet "fast start" requirements for power generators. By assigning this firm capacity on a priority basis to New England power generators, Eversource anticipates that the Access Northeast project will result in increased gas supply and reduced wholesale natural gas and power prices.

As part of the evaluation process regarding the selection of the Access Northeast project, a competitive solicitation process was conducted by the Eversource EDCs, in conjunction with National Grid. The competitive solicitation process produced 20 options from seven entities including owners and operators of major infrastructure assets in New England and Maritime Canada. The options submitted by the bidders ranged from the construction of incremental pipeline capacity to contracting for imported LNG to a combination of constructing incremental pipeline capacity and market area LNG storage.

To evaluate the proposals received by the Eversource EDCs, Sussex relied on a stepwise evaluation process that increased the breadth and depth of the evaluation with each successive step in the evaluation. Each proposal was evaluated quantitatively (i.e., a landed cost analysis) and qualitatively (i.e., the assessment of certain risk categories including: generation capacity served, peak day deliverability, flexibility, receipt point liquidity, construction risks, sponsor financial consideration, and the potential capacity mitigation opportunities).

The Access Northeast project and the Tennessee NED projects were identified as the best options to deliver natural gas to power generators connected to the Algonquin and Tennessee pipelines, respectively. The Access Northeast project was identified as the best solution with the capability to impact the natural gas infrastructure and wholesale power price existing in the New England region. As shown in Table 20, the Access Northeast project proposal provides cost-effective transportation while also having qualitative attributes that make it the optimal solution.

Table 20: Access Northeast and Tennessee NED Projects Comparative Evaluation

Project Name	Landed Cost Rank: Annual 2016/2017-2021/2022 Forwards	Landed Cost Rank: Winter 2016/2017-2021/2022 Forwards
Access Northeast	[redacted]	
NED Ex-LNG TGP Z4 Receipts		

Project Name	Relative Qualitative Evaluation: Winter Generating Capacity Served	Peak Day Deliverability	Fixed Demand Charges	Flexibility	Receipt Point Liquidity	Construction Risks	Sponsor Financial Condition	Capacity Mitigation Opporunities
Access Northeast	[redacted]							
NED Ex-LNG TGP Z4 Receipts								

Algonquin, as the developer of the Access Northeast project, has substantial experience constructing, operating, and expanding natural gas transportation in the New England region. That experience includes the currently underway AIM project that similarly will expand the Algonquin system, and the proposed Atlantic Bridge Project to expand the Algonquin and M&NP systems. The owners of Algonquin have the financial capability to fund and complete the project and are rated investment grade.

Importantly, the Access Northeast project will provide incremental access to natural gas supplied from the Marcellus and Utica shale basins. Both basins have shown remarkable growth in recent years and are currently projected to continue to grow during the term of the ANE Contract. By providing access to these stable, low-cost natural gas supplies at a reasonable cost, the ANE Contract are reasonable and appropriate to address natural gas infrastructure constraints in the New England region.

Lastly, it is critical to understand that committing to the Access Northeast project today will not preclude other options. As discussed in the Company's testimony, Eversource remains committed to pursuing its approved energy efficiency and clean energy programs. The ANE Contract, however, constitute a major step forward in terms of addressing the critical problem of high winter natural gas and power prices.

Q. Does this conclude your direct testimony?

A. Yes, it does.