ATTACHMENT EVER-KRP-1

Curriculum Vitae for Kevin R. Petak

KEVIN PETAK

Vice President

Kevin Petak, Vice President of Oil and Gas Markets, has over 30 years of experience in the energy industry. Mr. Petak has directed numerous energy market analyses to support strategic planning needs at energy companies, including natural gas producers, pipelines, and energy marketing affiliates. These analyses have investigated the impact of pipeline expansions and growing gas supply on gas prices, the effect of weather on gas markets, and strategies to comply with stricter emissions regulations. These analyses have been widely used to support facilities/fuels/contracts management and planning, mergers and acquisitions, investment decisions, risk management, and hedge strategies.

Mr. Petak has recently directed analyses for New England gas supply for ISO-NE that assess the ability of gas infrastructure to satisfy New England's gas market needs during peak demand periods. In addition, he has directed studies for the States of Arizona, Nevada, and New York, and has also directed recent modeling work for the Interstate Natural Gas Association of America (INGAA) that has studied the need of gas infrastructure. Much of Mr. Petak's work focuses on projecting growth of North American natural gas markets, and his modeling work has been an integral part of analyses that have investigated the cost effectiveness of new supplies to satisfy gas demand. This work relies on ICF's Gas Market Model, a modeling system that he developed. The gas market model is also the primary tool used for ICF's gas market subscription services, which Mr. Petak has developed and manages.

Prior to joining ICF, Mr. Petak worked for nine years in Reservoir Engineering with Halliburton Company, a major energy services provider. While at Halliburton, he was responsible for reservoir, well test, and fracturing analysis. He has numerous industry publications in the areas of well test analysis and reservoir modeling.

Years of Experience

- Professional start date: 06/1984
- ICF start date: 06/1993

Education

- MS, Management Administrative Sciences, University of Texas, 1992
- BS, Petroleum and Natural Gas Engineering, Pennsylvania State University, 1984

Certifications

- Engineer in Training, EIT, Oklahoma, 1986

Awards

- Dallas Chapter Financial Executive Institute Outstanding MBA Graduate Award, 1992
- Oklahoma Society of Professional Engineers Young Engineer of the Year Award, 1988

Key Skills

- Accomplished gas market analyst, having completed over 100 different projects investigating gas market issues.
- Skilled market modeler with over 20 years of experience in economic modeling focused on assessing gas supply, demand, infrastructure, and prices.
- Lead analyst for key gas market studies.

Relevant Project Experience

Gas Market Analyses

Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs—ISO New England, Inc

As Project Manager, Mr. Petak managed ICF's assessment of supply capability to satisfy winter and summer peak day demand in New England, including all gas demand. The analysis included a detailed look at the pipeline infrastructure and LNG peak-shaving capabilities.

Natural Gas Pathways—Canadian Energy Research Institute (CERI)

As Project Manager, Mr. Petak managed ICF's scenario analysis for the Natural Gas Pathways project. The scenarios assess how Canadian production and prices change under completely different "future worlds". The results of the analysis were presented recently at CERI's Natural Gas Pathways conference in Calgary.

Gas Infrastructure Analyses—Interstate Natural Gas Association of America (INGAA)

Mr. Petak directed a number of studies for INGAA and others that investigate the need and impact of pipelines and storage in different markets. These studies quantified the amount and cost of new capacity that is likely to be built over time.

Gas Infrastructure Regional Planning Studies and Critical Infrastructure Analysis—U. S. Department of Energy (DOE), INGAA, and AGA

Mr. Petak has directed regional planning studies that quantify the ability of markets to withstand different levels of disruption under various market conditions (e.g., different weather scenarios) during both a peak month and peak day.

Natural Gas Market Review for Ontario—Regulatory Policy & Compliance, Ontario Energy Board

As Project Manager, Mr. Petak managed ICF's review of Ontario's natural gas market. The review included ICF's base case projection of market conditions that are likely to prevail in Ontario through 2020. The outlook included an assessment of Ontario's gas demand and investigated the likely sources of gas supply for Ontario.

Impact of Energy East Project on Ontario's Gas Consumers—Ontario Energy Board

As Project Manager, Mr. Petak managed ICF's assessment of TransCanada's Energy East Pipeline Project on Ontario's natural gas consumers. The project investigated the potential consumer cost and tariff increases that could result from pipeline capacity being removed from service.

New England Consumer Cost Impact Study

Mr. Petak has directed a study for Eversource that assesses the reduction in gas prices and consumer cost savings that could result from pipeline projects completed into New England.

California Gas-Renewables Integration Study—CIEE/CEC

Mr. Petak was the principle investigator on a two-year effort to evaluate western U.S. gas infrastructure capability to satisfy gas market needs under different renewables growth scenarios using ICF's Regional Infrastructure Assessment Modeling System (RIAMS).

New York Gas Infrastructure Analysis—NYSERDA

Mr. Petak directed an analysis that has investigated New York's gas infrastructure needs during the next 10 years. The results became a key input to New York's 2009 State Energy Plan.

Consumer Cost Impacts of the Atlantic Coast Pipeline Project – Dominion

Mr. Petak directed an analysis that has investigated the gas price changes, consumer cost reductions for the States of Virginia and North Carolina, and employment gains that could result from the Atlantic Coast Pipeline project.

Marcellus/Utica Production Area Study – A Number of O&G Producers

Mr. Petak has directed market analyses that investigate the production changes, pipeline development and price impacts of incremental Marcellus/Utica gas production over time. The studies investigated the amount of pipeline infrastructure that could be developed through 2025.

Nevada Gas Market Analysis—Nevada Power and Sierra Pacific Power Companies

Mr. Petak directed the analysis that investigated supply and demand trends for Nevada and Nevada's gas infrastructure needs over the next 20 years. Results from the analysis were filed by NPC and SPPC as part of their Integrated Resource Plan.

Gas Supply Contracting Study - Vale

For a mining company, Mr. Petak directed a study that investigated options for contracting gas supply in North America. Specifically, the study investigated the potential prices and costs of different gas supplies and investigated transportation options for supplies.

Southern Star Valuation – PSP Investments

For a major Canadian Pension Plan, Mr. Petak directed an analysis that investigated the value of the Southern Star Pipeline system. The study assessed the value of the contracts on the system, and identified upside potential for the pipeline.

Alliance Pipeline Valuation – A Major Canadian Investment Firm

Mr. Petak directed an analysis that investigated the value of the Alliance Pipeline. The study assessed the utilization and potential expansion of the system. The analysis focused on both gas and liquids transport to the Aux Sable processing facility.

LNG Export Price Impact Studies – A Number of LNG Project Developers

Mr. Petak directed market analyses that assess the potential gas price impacts that result from LNG exports. The studies have focused on LNG exports from the U.S. Gulf Coast and Western Canada. The studies also identify facilities needed to develop the exports.

Industry Studies

North American Gas Market Analysis—National Petroleum Council

Mr. Petak directed the modeling work for the widely publicized North American natural gas market analysis completed by the National Petroleum Council for the U.S. Secretary of Energy in 2003. The study addressed the adequacy of gas supply and gas industry infrastructure to satisfy a growing gas market. The study identified system requirements and infrastructure to satisfy gas demand over the next 15 years.

Comprehensive Study of Waxman-Markey GHG Bill—Americas Natural Gas Alliance (ANGA)

Mr. Petak directed modeling work to investigate the impacts of the Waxman-Markey greenhouse gas regulation on the natural gas industry.

Gas Market Subscription Services

Gas Market Compass—Numerous Clients

Mr. Petak directs the production of ICF's quarterly-produced base cases for the North American natural gas markets, provided by this service.

Detailed Production Report—Numerous Clients

Mr. Petak manages the production of this service that provides ICF's projection of gas, oil, and natural gas liquid production over time.

Midstream Infrastructure Report – Numerous Clients

Mr. Petak manages the production of this subscription product that assesses the amount of midstream infrastructure, including gas pipeline capacity, that is likely to be built in markets throughout North America over the next 20 years.

Relevant Presentations and Publications from 2011-present

Kevin Petak and Mark Babula, IEEE Power and Energy Magazine, *The Cold Truth, Managing Gas-Electric Integration: The ISO New England Experience*, November/December 2014

Mark Babula, Kevin Petak, Wayne Coste, Leonard Crook, and Frank Brock. ISO-NE Planning Advisory Committee, *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Power Generation Needs*, Phase 1, Phase 2, and Phase 3 Studies, 2011, 2012, and 2013, Boston, MA

Kevin Petak, CERI 2013 Natural Gas Conference, March 2013, *Examining the Drivers Behind Marcellus and Utica Shale Gas Development*, Calgary, AB

Kevin Petak, Joint Resource Planners Forum / CREPC / SPSC Meeting, October 2012, *Studying Gas-Electric Integration*, San Diego, CA

Employment History

ICF International, Vice President, Fairfax, VA. January 2007-present.

Energy and Environmental Analysis (acquired by ICF), Director. Arlington, VA, June 1993-December 2006.

Halliburton Company. Development Engineer. Duncan, OK, and Dallas, TX, June 1984-May 1993.

ATTACHMENT EVER-KRP-2

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

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

Prepared for

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

Prepared by

ICF International
9300 Lee Highway
Fairfax, VA 22031

December 18, 2015

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Executive Summary

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

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

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

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

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

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

[2] New England residential and commercial demand is the highest during the peak winter months of December, January and February and LDCs will draw heavily on existing natural gas infrastructure.

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

[4] Ibid.

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

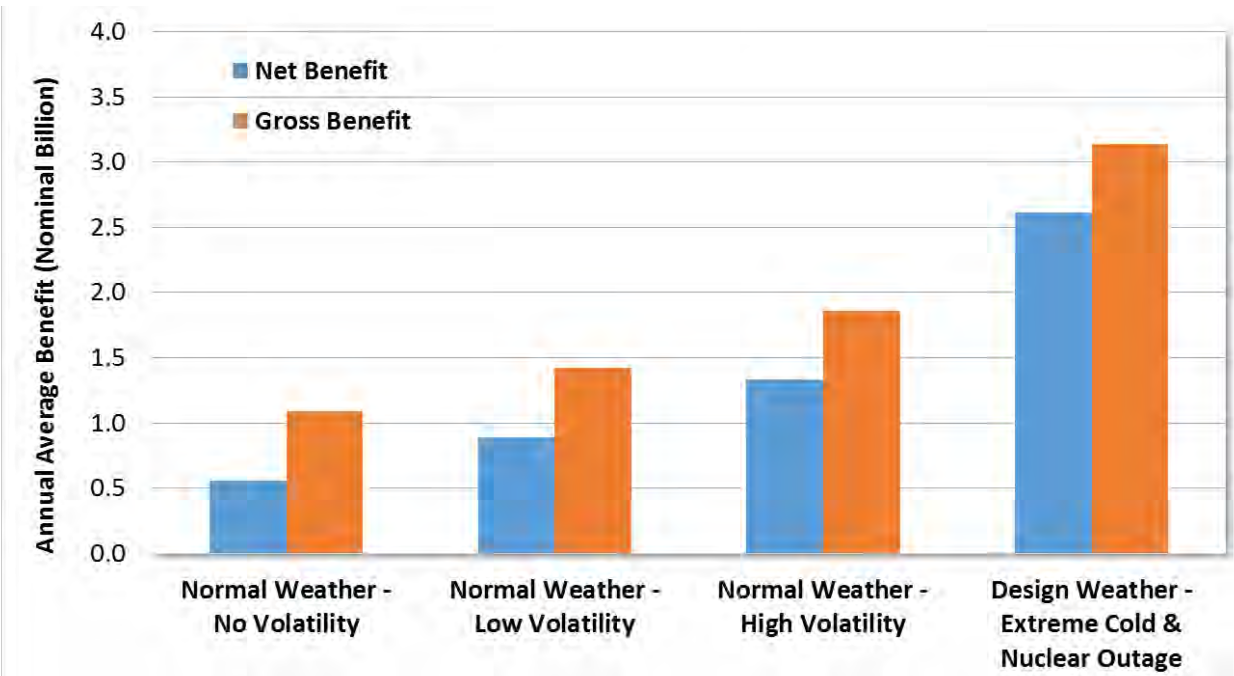
[6] Design winter conditions are dependent on how companies define it, but it is generally a very cold winter with a coldest day, based on observed weather over the last 20-30 years.

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

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

Source: ICF

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



Source: ICF

Key observations and conclusions are summarized below.

Outlook for New England Gas Market

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

In recent years, New England has steadily increased its reliance on natural gas fired generation as coal and nuclear power plants have been retired. This growing reliance on natural gas is expected to continue

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

during the next few years with the retirement of additional nuclear, coal, and oil-fired capacity (e.g., Vermont Yankee, Brayton Point, Mount Tom, and Pilgrim) and the addition of new gas-fired capacity (Footprint Power). Cumulative firm retirements of nuclear, coal and older oil/gas units in New England are expected to reach 4,150 MW by 2019.[8] In the future, the New England electricity market will be increasingly served by a combination of natural gas, renewable and energy efficiency sources. ICF projections assume that all states will achieve their stated Renewable Portfolio Standards ("RPS") targets on schedule.[9] Growth in electric load will be partially offset by energy efficiency and passive demand response gains, reducing projected growth in net energy load to only 0.04% per year through 2035. Notwithstanding these increases in renewables and energy efficiency, ICF projects that the region will require approximately 1,740 MW of new gas-fired generating capacity by 2019, further increasing power sector gas demand. As a result, the demand for natural gas from the power sector has increased, with the growth rates being greatest in the winter heating season when traditional heating demand for natural gas is also at its peak.

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

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

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

New England's access to gas supplies has become further constrained by the reduced frequency of firm cargoes at the regions' LNG import terminals. LNG is a global commodity and importers to New England largely operate without firm contracts to sell to New England buyers, instead preferring to seek the highest prices available wherever that may be. The Canaport LNG import terminal in New Brunswick has also provided gas supplies to New England. In 2013, Repsol S.A., the majority owner and manager of the Canaport terminal, sold its long-term LNG supply contracts and ship charters, leaving Canaport with minimal firm supply contracts. LNG imports also come directly into New England via the Everett terminal.

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

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

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

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

Electric Market Benefits from Access Northeast

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

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

ICF estimates that, on average, Access Northeast would save New England electric consumers $1.4 billion to $1.9 billion per year over the period of 2019 to 2035. For context, ISO-NE reported that "the total value of the region's wholesale electricity markets, including electric energy, capacity, and ancillary services markets, rose…to about $9.9 billion in 2014 … [and electric] energy comprised $8.4 billion of the total."[15] The potential cost savings stem from the highly correlated nature of natural gas prices and wholesale power prices in New England, and the fact that lower gas prices resulting from Access Northeast capacity reduce wholesale power prices. These savings would ultimately extend to all New England electric

[12] U.S. Energy Information Administration, U.S. Natural Gas Imports by Point of Entry, http://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm, accessed October 28, 2015.
[13] U.S. Energy Information Administration, Ibid.
[14] 18 Bcf/d is dry gas output from the Marcellus/Utica basins alone. It does not include any liquids production and conventional production in the Appalachian region. "Wet" gas and conventional production from the area pushes the total above 20 Bcfd.
[15] ISO-NE Press Release on 2014 Annual Markets Report, at http://www.iso-ne.com/static-assets/documents/2015/05/amr14_release_05202015_final.pdf

consumers, including those in the states not directly receiving natural gas from the Access Northeast project.

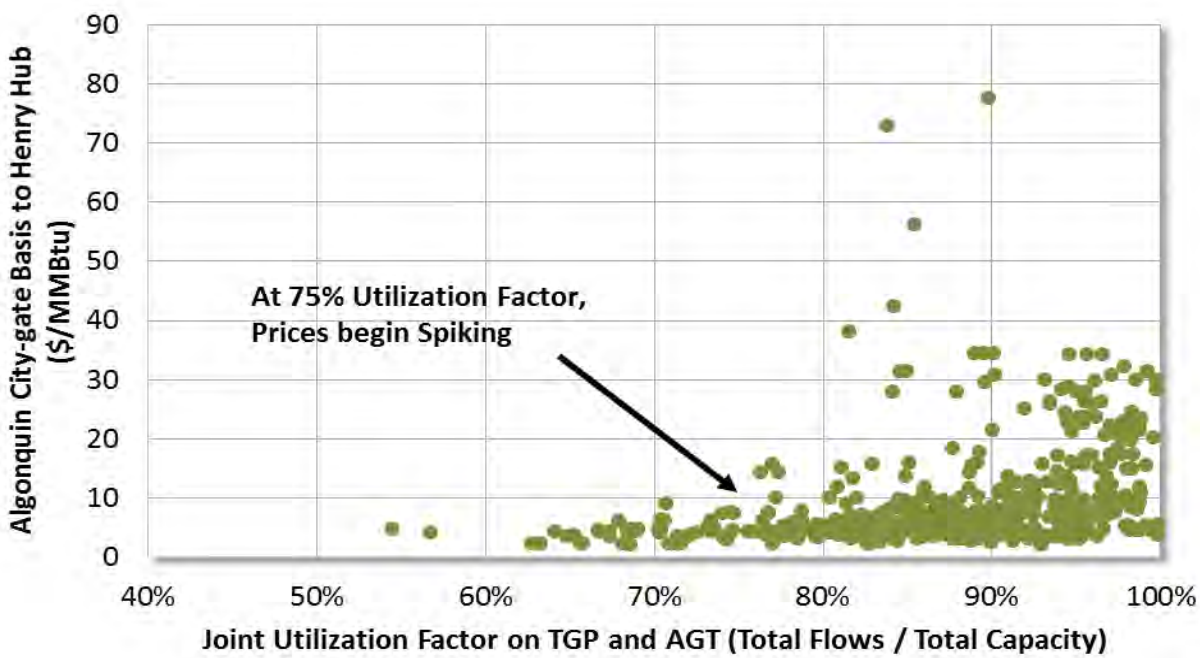
Under design winter weather conditions and a nuclear outage, Access Northeast would save New England electric consumers $2.6 billion over a five month winter period

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

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

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

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



Source: Point logic, Ventyx

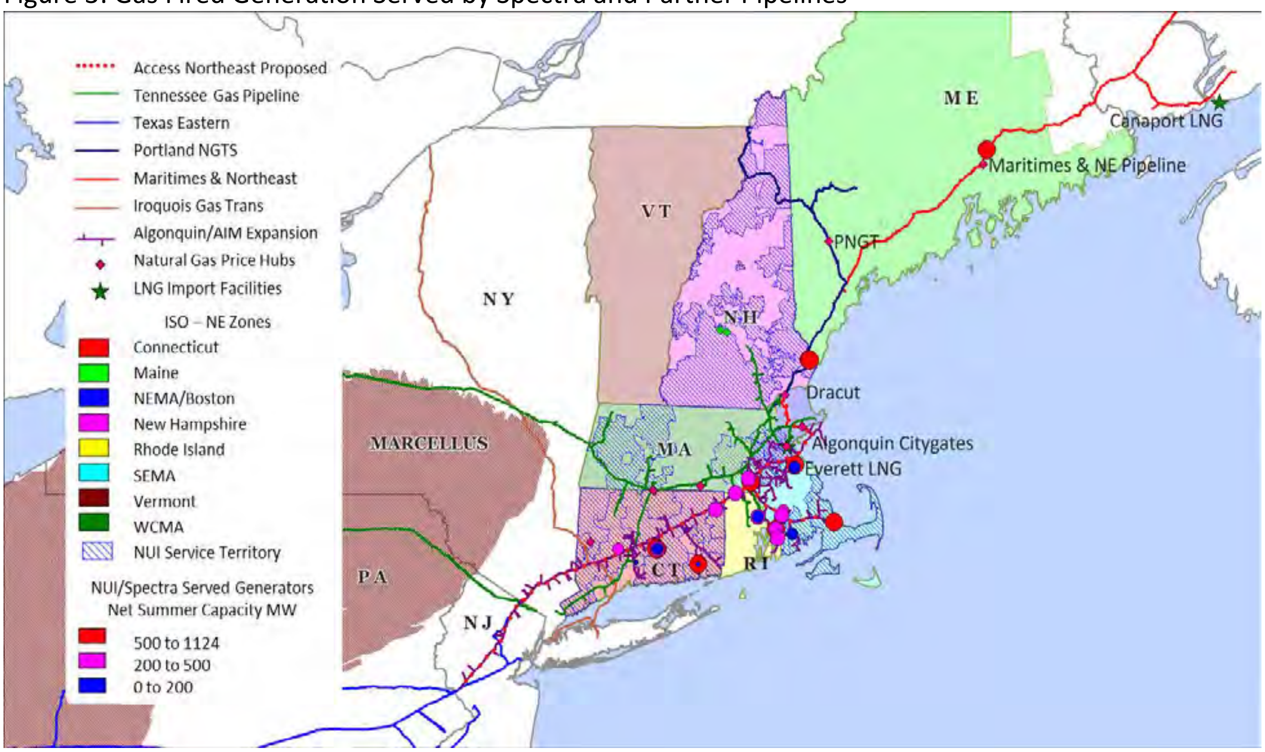
Reliability and Other Benefits from Access Northeast

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

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

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

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



Source: Ventyx

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

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

Access Northeast will support the region’s renewable energy goals

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

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

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

Introduction

Study Background

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

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

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

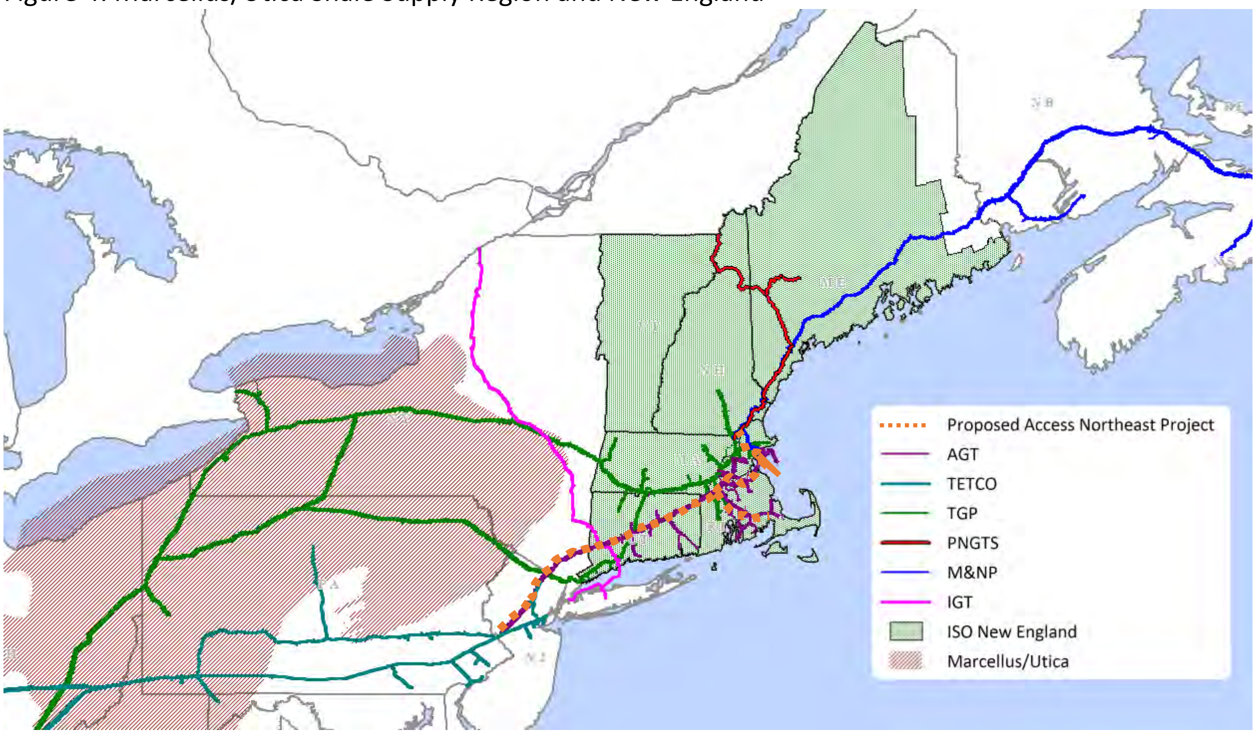
In 2013, the governors of all six New England states issued a joint statement on natural gas and electric system interdependency, and the need for regional cooperation on energy infrastructure issues.[24] In 2015, the governors again released a joint statement, acknowledging that "New England continues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

[20] http://www.iso-ne.com/static-assets/documents/2015/03/icf_isone_van_welie.pdf slide 7.
[21] Babula, M. & Petak, K. (2014). The Cold Truth, Managing Gas-Electric Integration: The ISO New England Experience. IEEE Power & Energy Magazine, November/December 2014, pp 20-28.
[22] A collaboration between ISO New England and regional stakeholders, this project focused on developing a short-term, interim solution to filling a projected "reliability gap" of megawatt-hours (MWh) of energy that would be needed in the event of colder-than-normal weather during winter 2013/2014. The solutions included a demand side response program, an oil inventory service, incentives for dual fuel units, and market monitoring changes.
[23] The other states are Hawaii (1), Alaska (4), New York (5) and California (8).
[24] http://nescoe.com/uploads/New_England_Governors_Statement-Energy_12-5-13_final.pdf

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

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

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

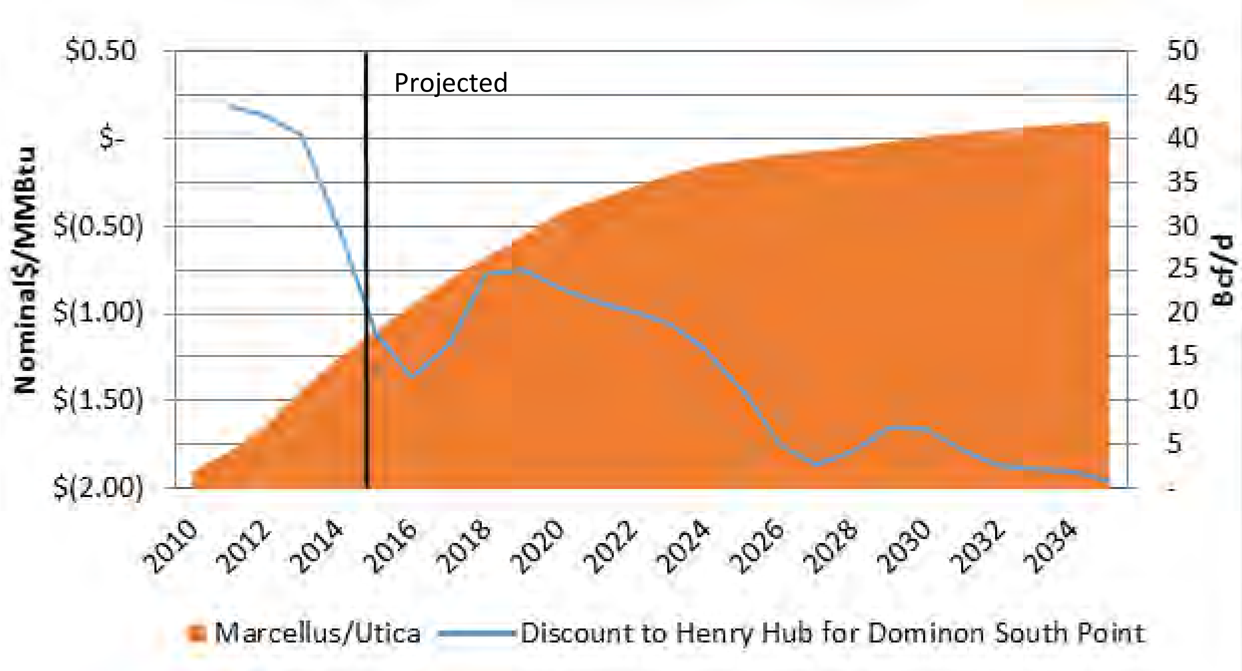


Source: ICF, Ventyx

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

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

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



Source: ICF, SNL

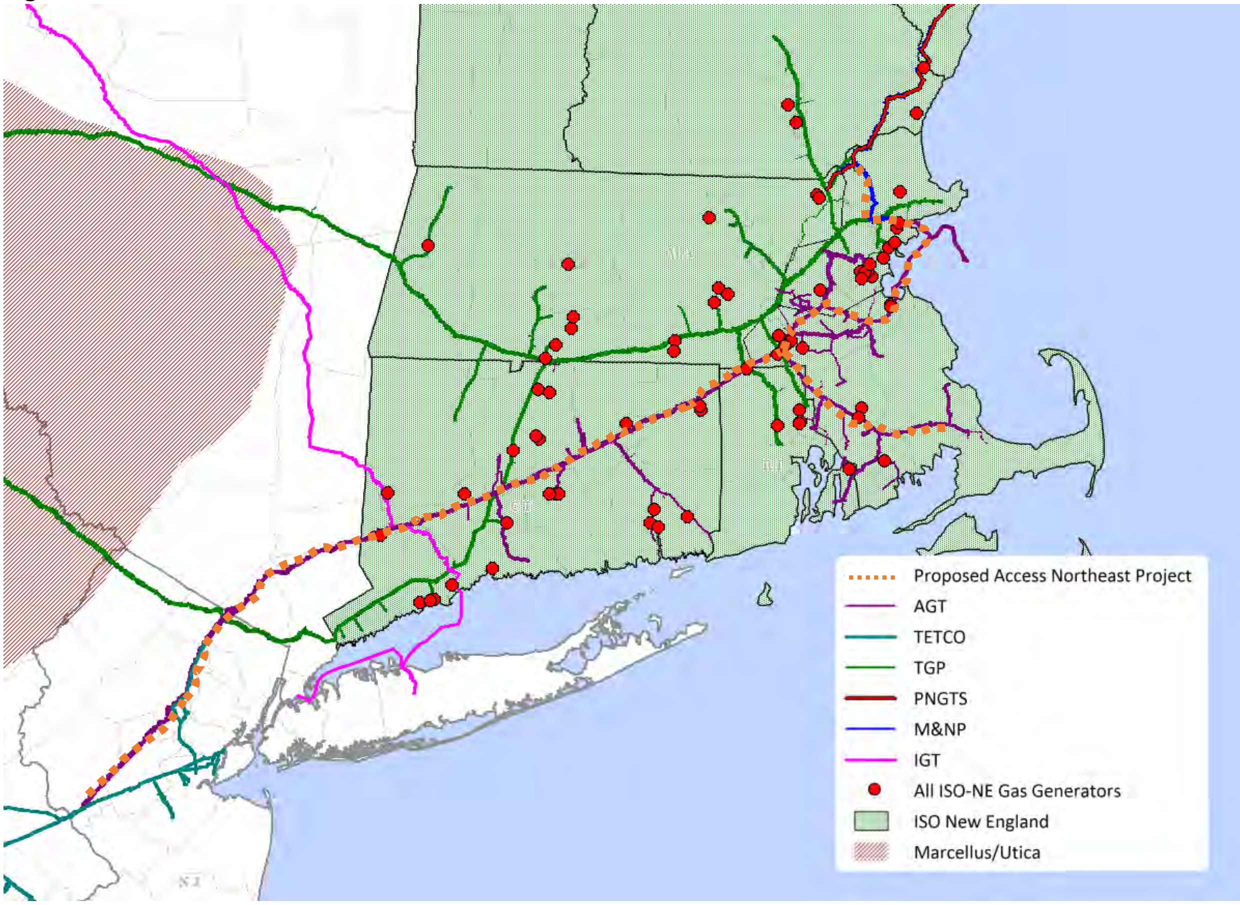
Project Description

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

[26] Basis presented here is TGP Z4- Line 300 price minus Henry Hub price.

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

Figure 6: Access Northeast Overview



Source: ICF, Ventyx

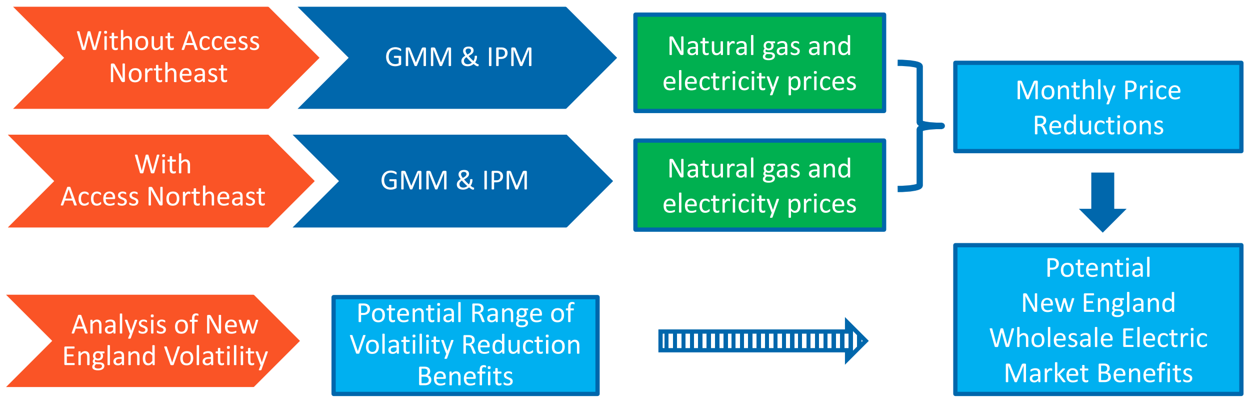
Analytical Approach

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

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

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

Figure 7: Cost Savings Analysis Methodology



Source: ICF

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

New England Energy Market Fundamentals

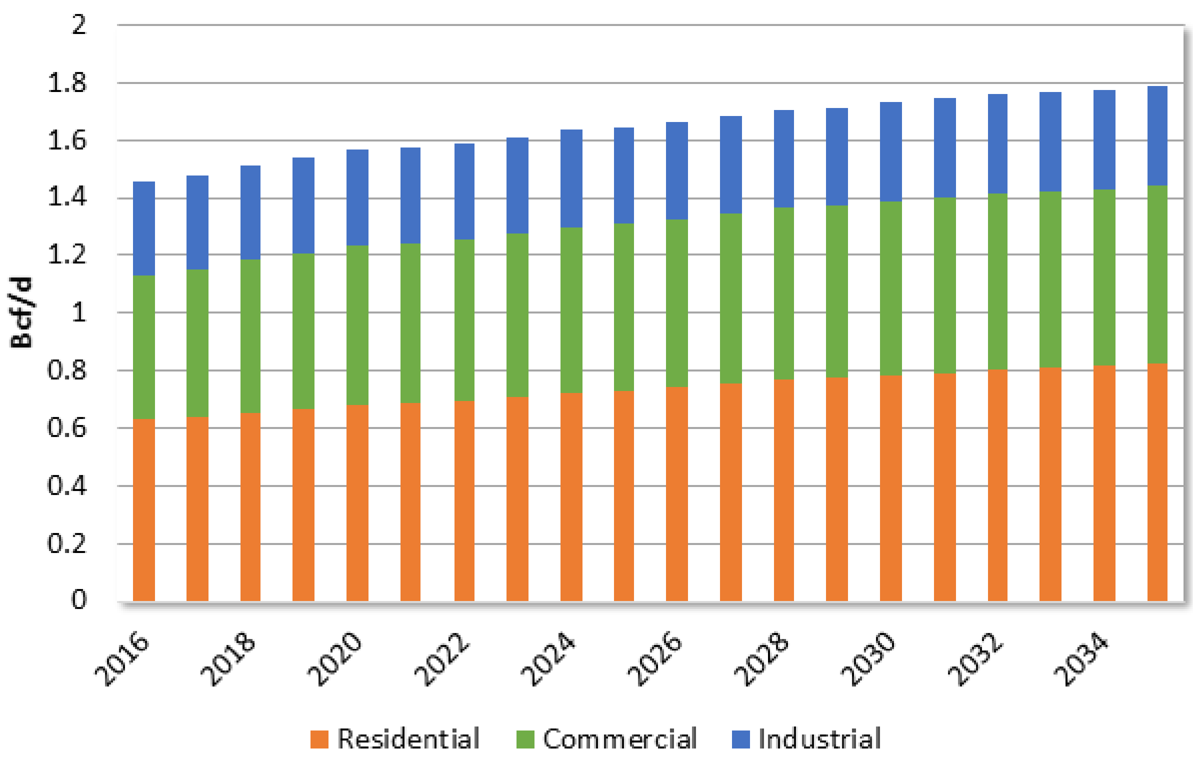
For this analysis, ICF revised its October 2015 Base Case to reflect Eversource's assumptions regarding New England natural gas and electric market fundamental development trends through 2035.

Residential/Commercial Demand

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

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

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



Source: ICF

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

Industrial Demand

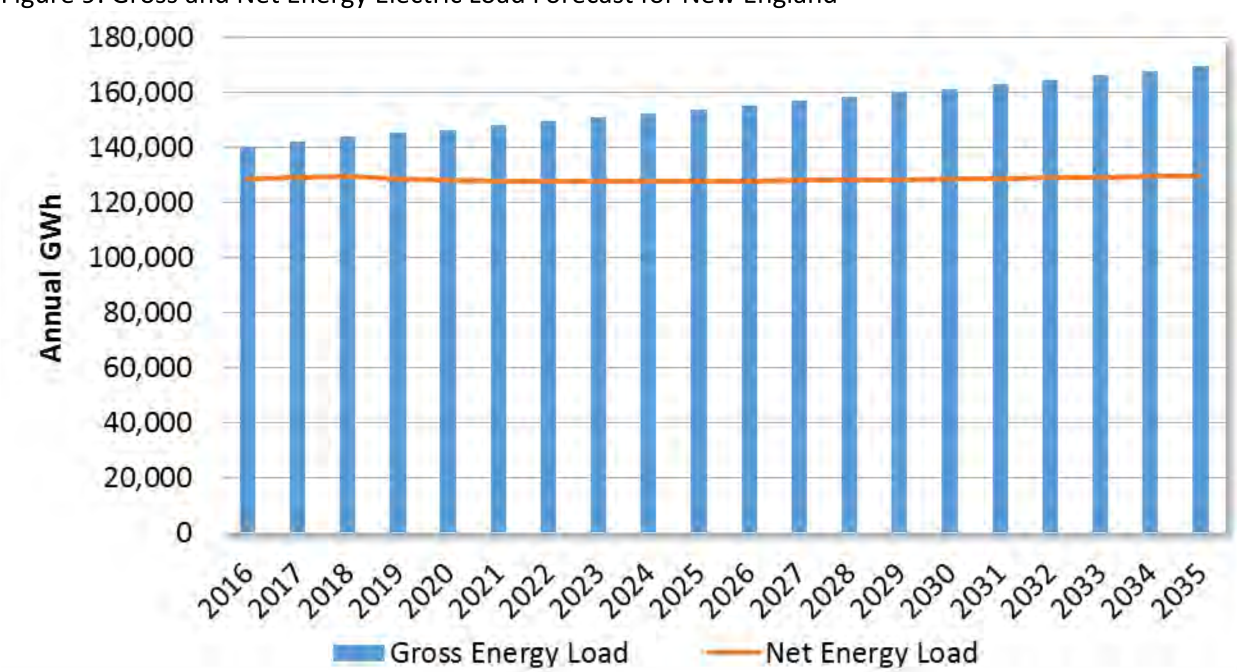
The industrial sector accounts for a relatively small share of New England's total gas demand, and ICF projects very little growth in this sector. As shown in Figure 8 above, annual average industrial demand is projected to be nearly flat at approximately 0.33 Bcf/d throughout the projection, as there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

Gas Demand for the Electric Sector

Electric Load Growth

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

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



Source: ICF, ISO-NE

Capacity Retirements and Builds

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

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

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

Source: ICF

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

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

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

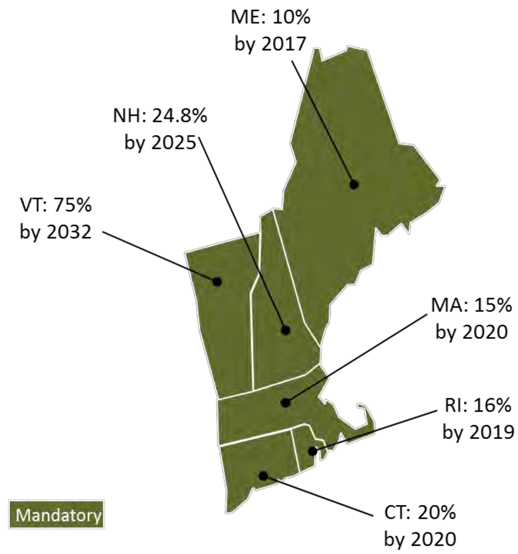
Source: ICF

[29] Retirements considered firm if they are permanently delisted units or if they have submitted a non-price retirement request that ISO-NE has accepted.
[30] Solar does not include "behind the meter" residential and commercial solar installations, which are not included in the ISO-NE queue. The 2015 ISO-NE CELT Forecast assumptions used in the modeling are net of these "behind-the-meter" solar installations.

Renewables

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

Figure 10: New England State RPS Standards



Source: ICF, state's RPS

Environmental Regulations

For this analysis, ICF assumes that federal maximum achievable control technology (MACT) standards, consistent with those set by the Environmental Protection Agency (EPA) in its final mercury and air toxics standards (MATS) released on December 21, 2011, will be in effect throughout the projection. ICF also assumes that the EPA will not have an alternative to the current Clean Air Interstate Rule (CAIR) regulations, and that the current CAIR remains in place through 2017. In 2018, ICF-assumed standards tighten to the Cross State Air Pollution Rule (CSAPR) Phase II requirements.

Clean Power Plan (CPP)

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

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

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

Projected Supply Sources into New England

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

LNG Imports

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

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

Canadian Supplies via M&NP

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

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

Even as Eastern Canadian production and LNG imports have declined[31], gas demand in the Maritimes provinces has been increasing. While relatively small, at about 0.2 Bcf/d, demand in the Maritimes provinces uses supplies that could otherwise be exported to New England. Flows on the M&NP system have already reversed on occasion, with gas flowing north into New Brunswick. Even if Canaport continues

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

to import at or slightly above recent levels, the Maritime Provinces are likely to be net gas importers by 2020. As such, M&NP is unlikely to provide gas supplies during the winter peak starting in 2020.

Firm Pipeline and Supply Capacity into New England

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

Table 4: Assumed Winter Capacity from Existing Pipelines, Planned Expansions, and LNG Supplies to New England (Bcf/d)[1]

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

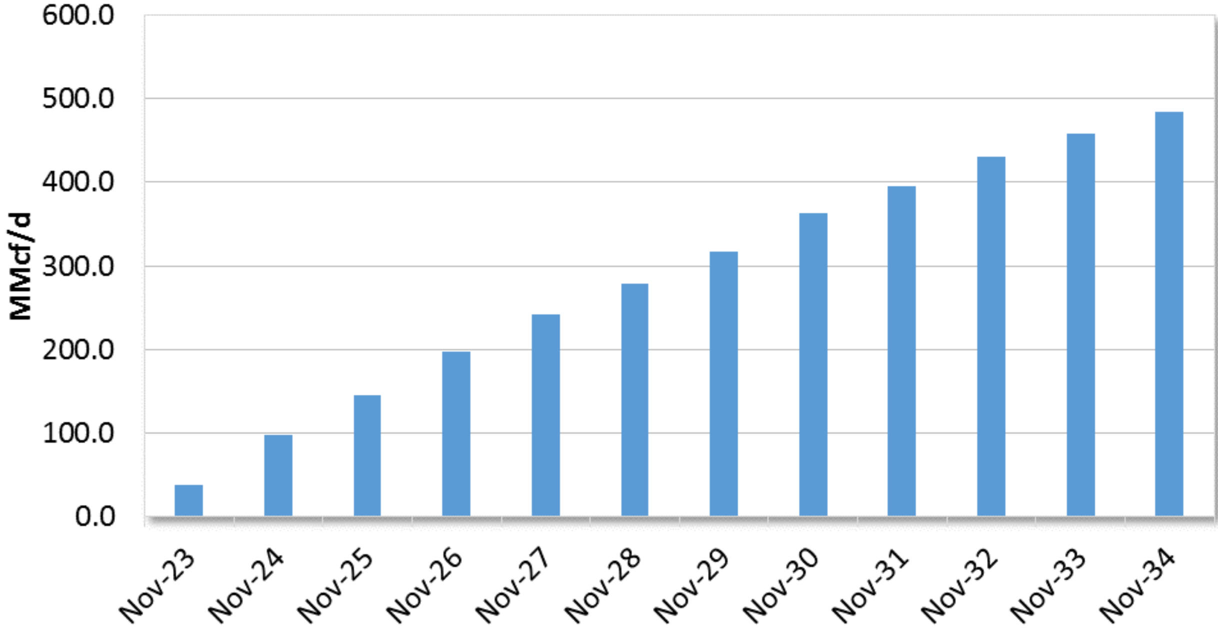
Source: ICF

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

LDC Incremental Expansions

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

Figure 11 – Cumulative Capacity Expansion for LDCs Load Requirements



Source: ICF

Electric Consumer Cost Savings - Normal Weather

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

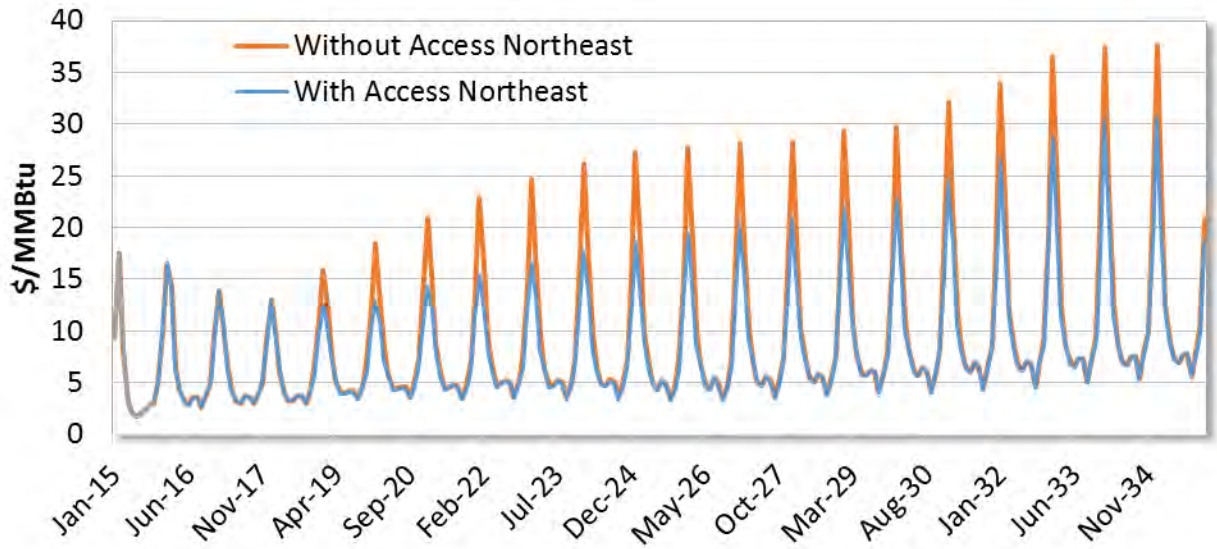
Natural Gas Price Impact – Monthly Average

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

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

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

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

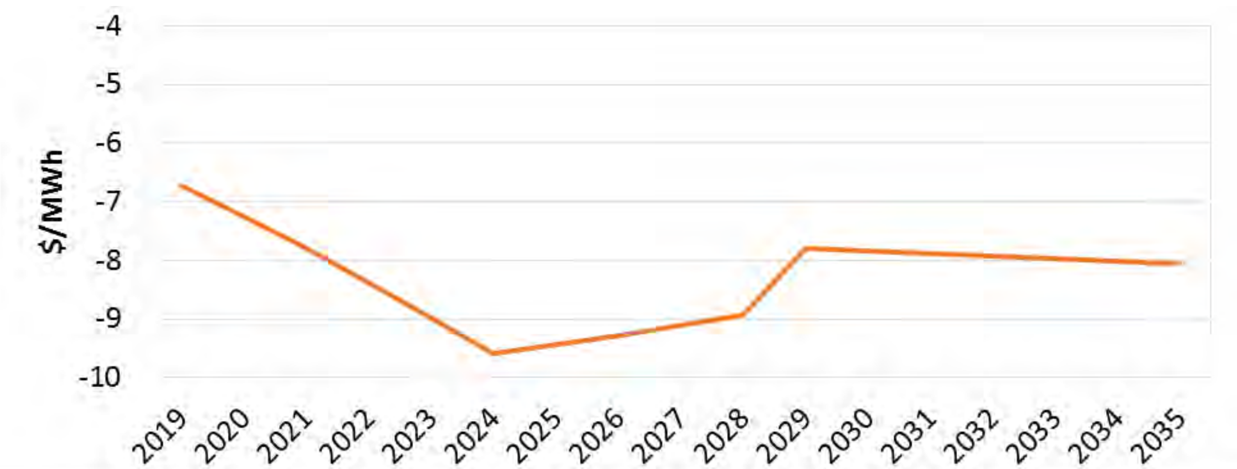


Source: ICF, SNL

Wholesale Power Price Impact – Monthly Average

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

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

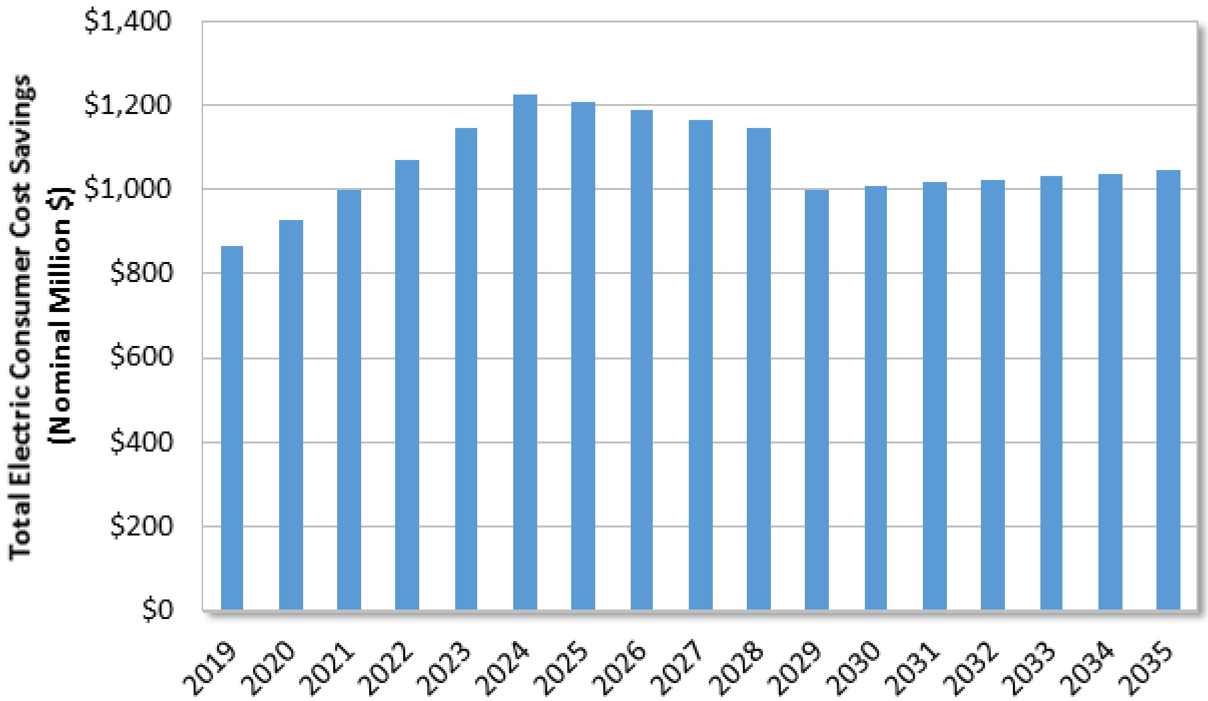


Source: ICF

Cost Savings from Average Price Reductions

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

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



Source: ICF

Benefits from Reduced Daily Gas Price Volatility

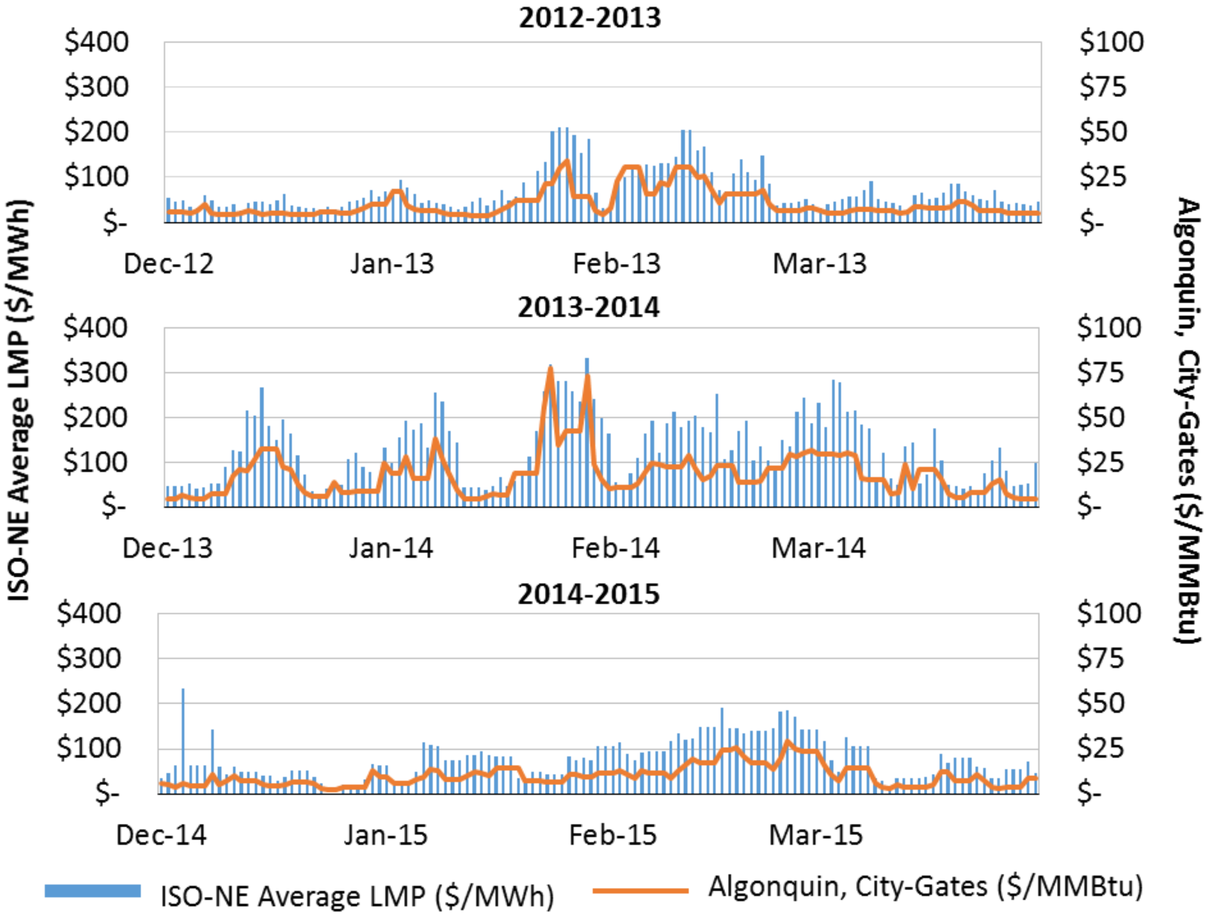
In addition to the monthly average price reduction that ICF has estimated using the GMM and IPM models, the gas supply capacity created by a project like Access Northeast would produce additional cost savings through reductions in daily natural gas and power price volatility. New England's gas and wholesale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

Price volatility is determined by complex market drivers, the analysis of which is beyond the scope of this report. For this study, ICF assumed certain ranges of reduction of frequency and magnitude of extraordinary price spikes as a proxy to measure the impact of volatility reductions. Figure 15 presents

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

daily Algonquin City Gate gas prices and ISO-NE daily average real-time locational marginal prices (RTLMPs—prices for electricity at different locations in the grid) for the past four winters.

Figure 15 - New England Historical Gas and Electric Price Volatility



Source: ICF, SNL, ISO-NE

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

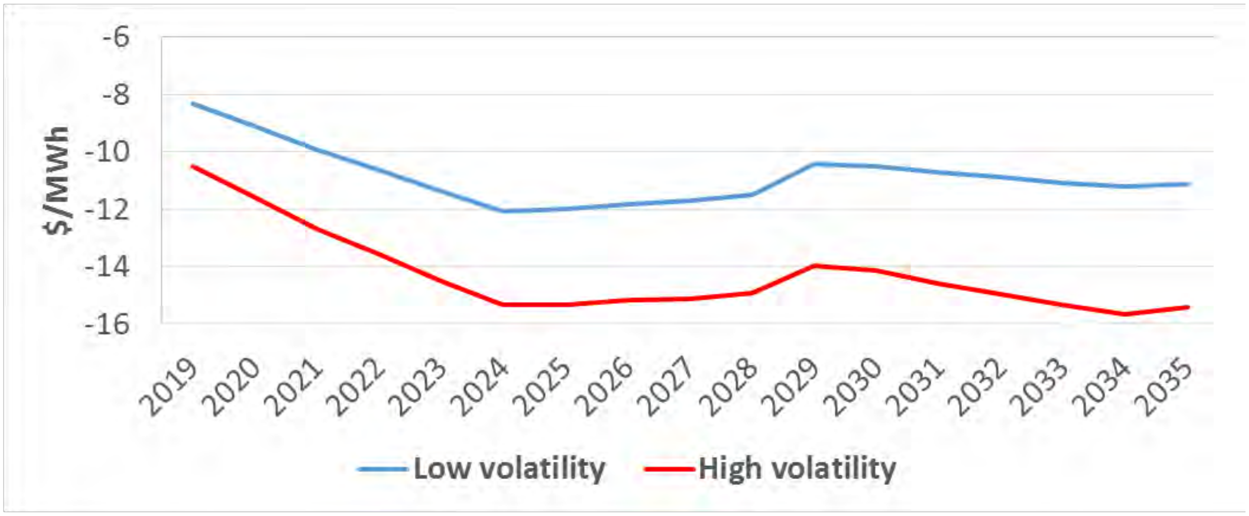
The range of Access Northeast's potential volatility reduction impacts is estimated assuming two volatility reduction levels:

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

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

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

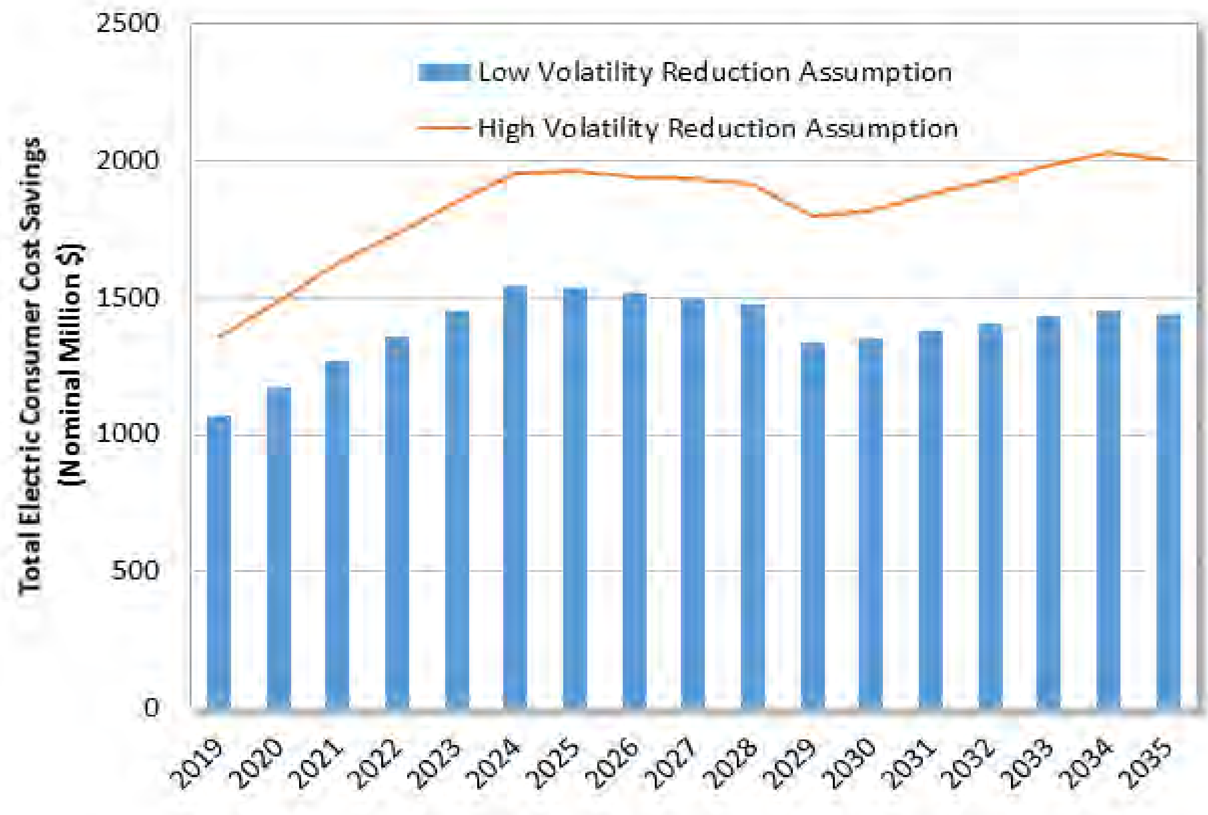
Figure 16: New England Annual Average Wholesale Power Price Reductions with Access Northeast



Total Estimated Impact to Consumers

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

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



Source: ICF

Total Estimated Impact to Consumers by State

The consumer benefits accrue to the different New England states differently, depending on the net load and the electricity price savings in each of the states; see Table 5. Consumers in Massachusetts, Connecticut, and New Hampshire are the states will benefit the most from the Access Northeast project, because these states have the largest percentage of load. The benefits in these three states account for 80% of the total ISO-NE benefits, with Massachusetts consumers accounting for about 44% of the benefits.

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

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

Source: ICF

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

Electric Consumer Cost Savings - Cold Weather and Nuclear Outage Scenario

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

Weather and RCI Demand Assumptions

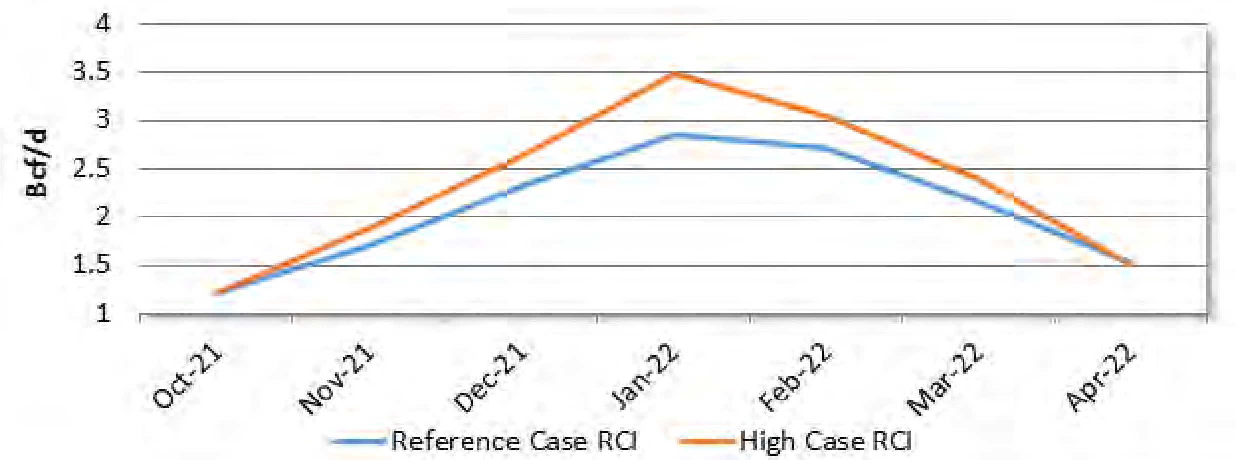
ICF utilized the design winter weather data provided by Eversource, to calibrate the design winter conditions in New England. Table 6 shows that the design winter is, on average, 17 percent colder than normal winter conditions. Figure 18 shows that residential, commercial, and industrial demand for the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

Table 6: Weather Assumptions

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

Source: Eversource, ICF

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



Source: ICF

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

Price Impact and Cost Savings

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

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

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

Source: ICF

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

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

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

Source: ICF

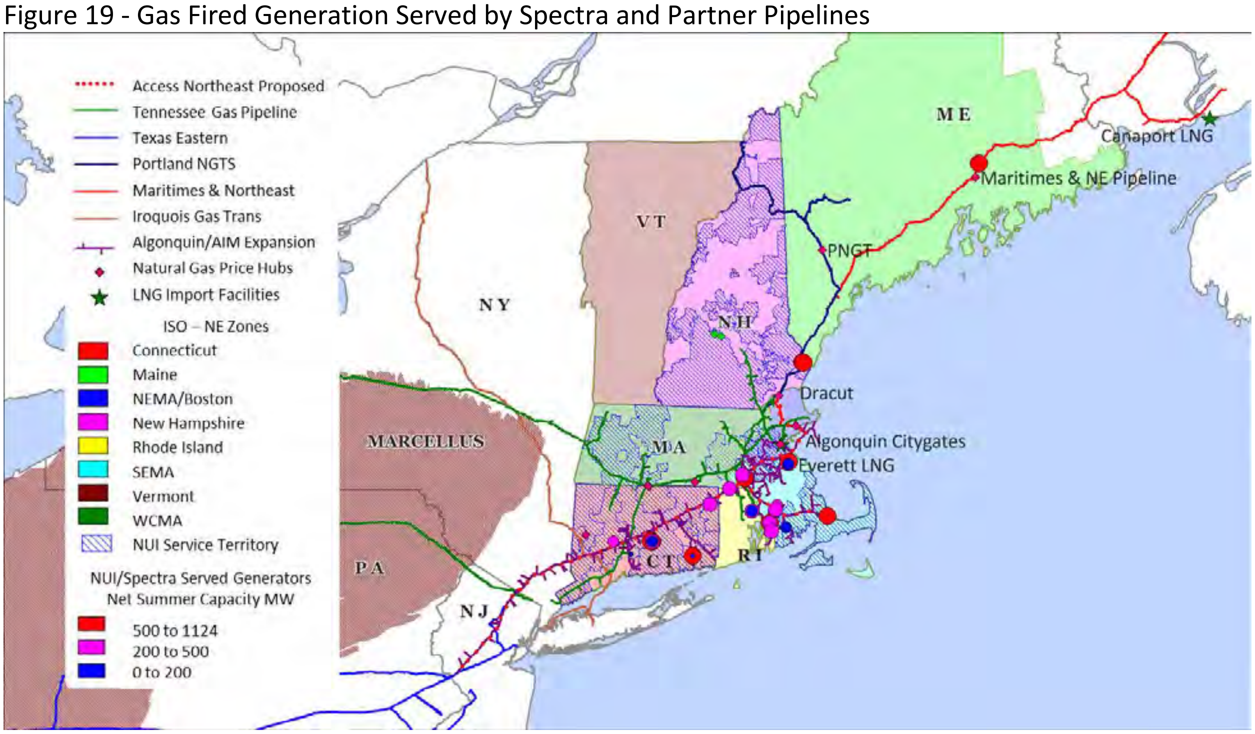
[35] Annualized savings are calculated as savings from November 2021 to October 2022.

Reliability and Other Benefits

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

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

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



Source: Ventyx

The ISO-NE has developed a market enhancement that is intended to improve generation availability in order to mitigate the adverse consequences of reliability shortage events. This program is known as "Pay

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

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

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

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

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

Source: PEPCO

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

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

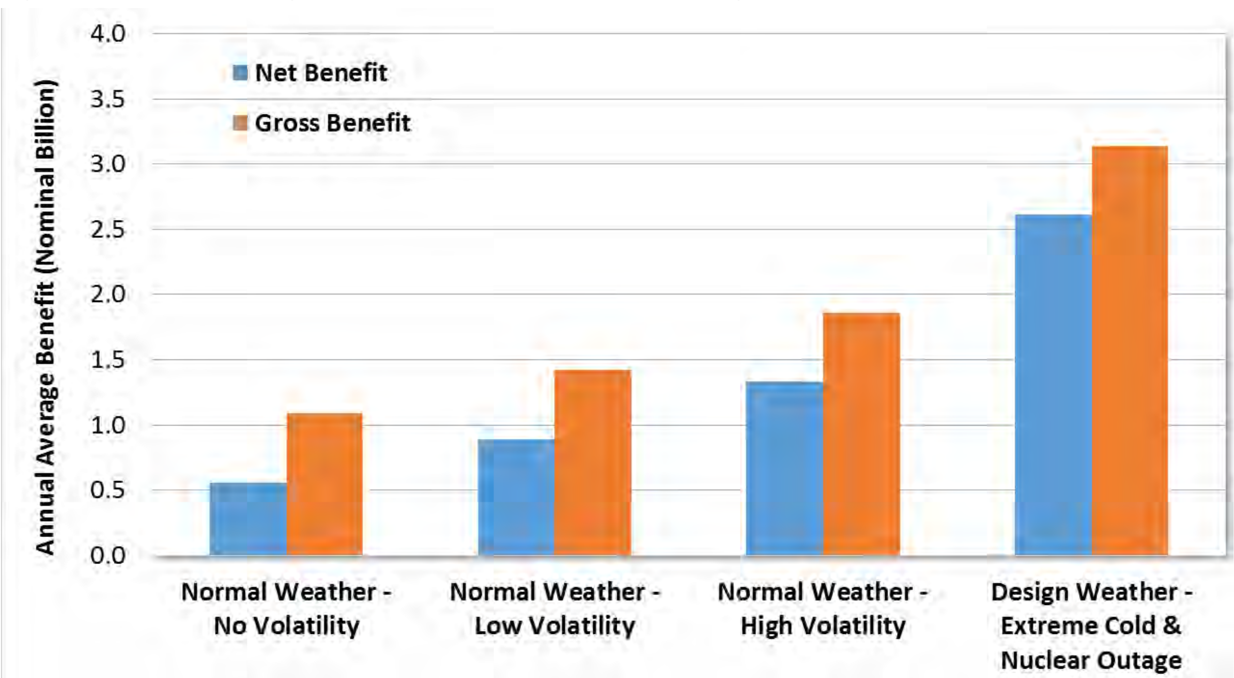
Cost / Benefits of Access Northeast

The portion of Access Northeast that will serve electric generation in New England, assumed in ICF's analysis is estimated to cost $2.4 billion. Assuming this translates into a $526 million annual cost, after taking into account the return on the capital investment and O&M costs annually to operate the capacity, the estimated benefits of Access Northeast to New England exceed its costs in all scenarios.

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

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

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



Source: ICF

The net benefits to New England, ranging from $1.0 billion to $2.7 billion, assumes that New England's electric consumers bear the full cost of the electric portion of the project, so those costs are netted out of the total savings that ICF has estimated. However, the cost savings to consumers would be greater if projected revenues for pipeline reservation charges paid by electric generators were to be credited back to the consumers as is proposed. We also estimate that the majority of the $2.4 billion investment required for the project would be recovered from the cost savings in a single extreme winter (design winter), similar to the 2013/14 winter. Furthermore, consumers in Massachusetts, Connecticut, and New Hampshire stand to benefit the most from the electric savings due to Access Northeast, due to the allocation of load.

Appendix: Description of ICF Models

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

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

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

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

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

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

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

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

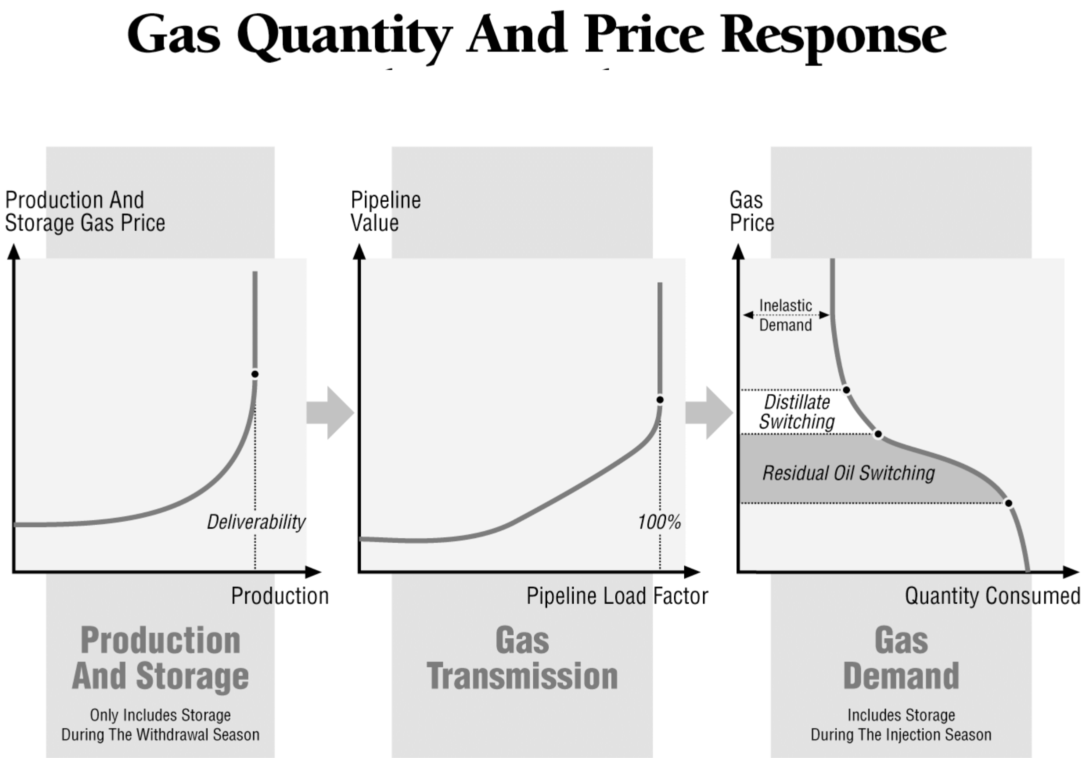


Figure 2: GMM Structure

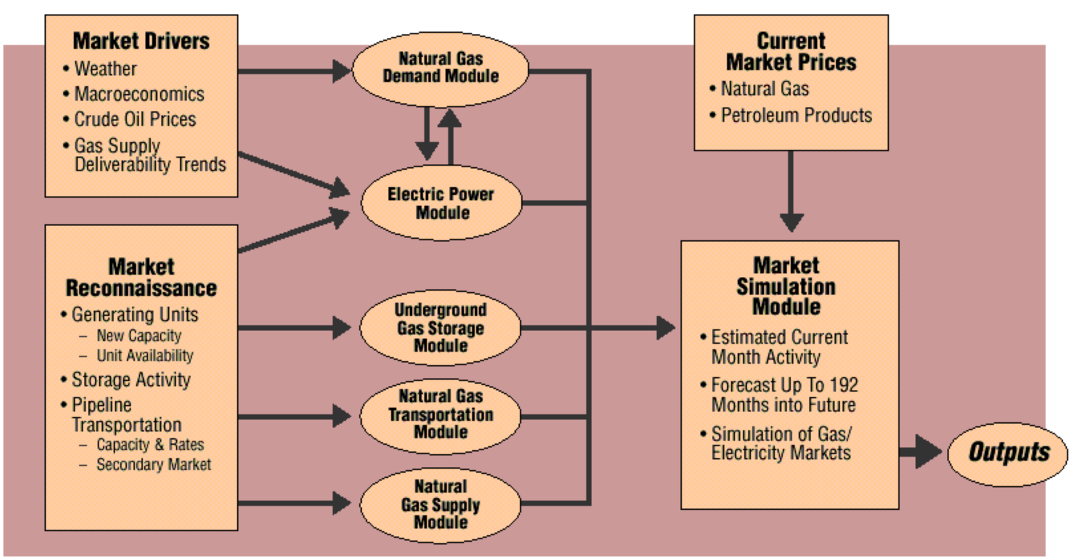
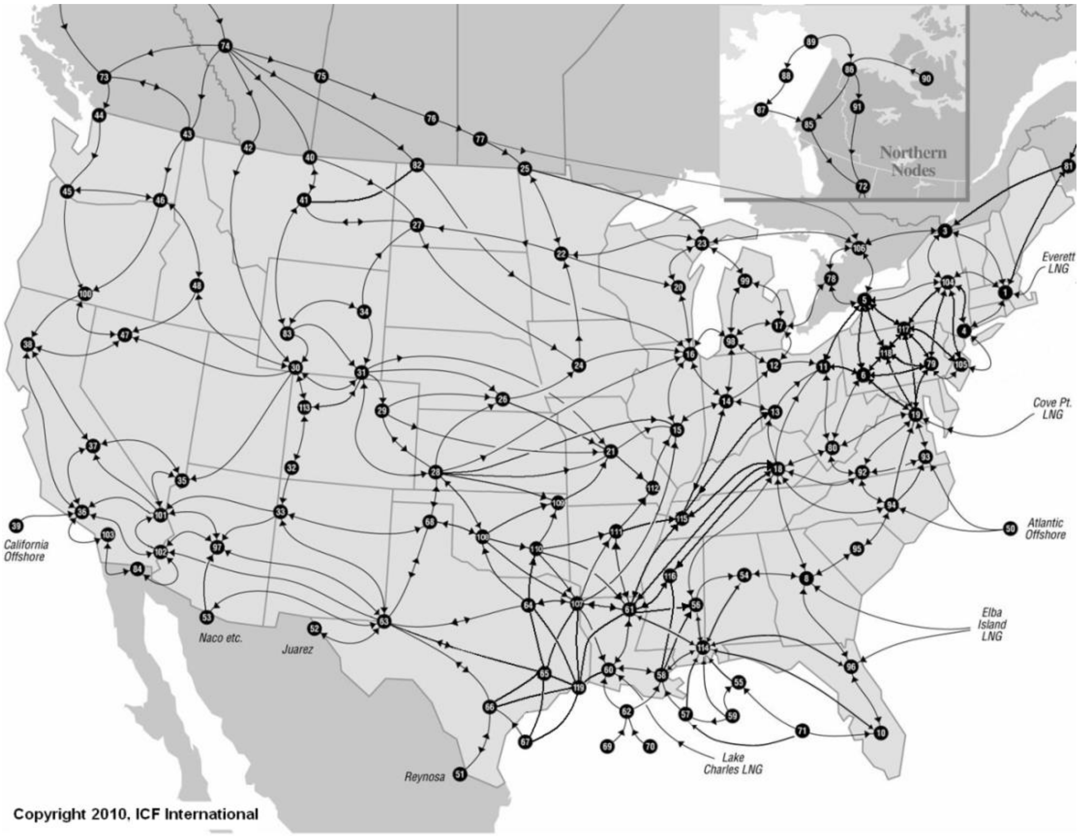
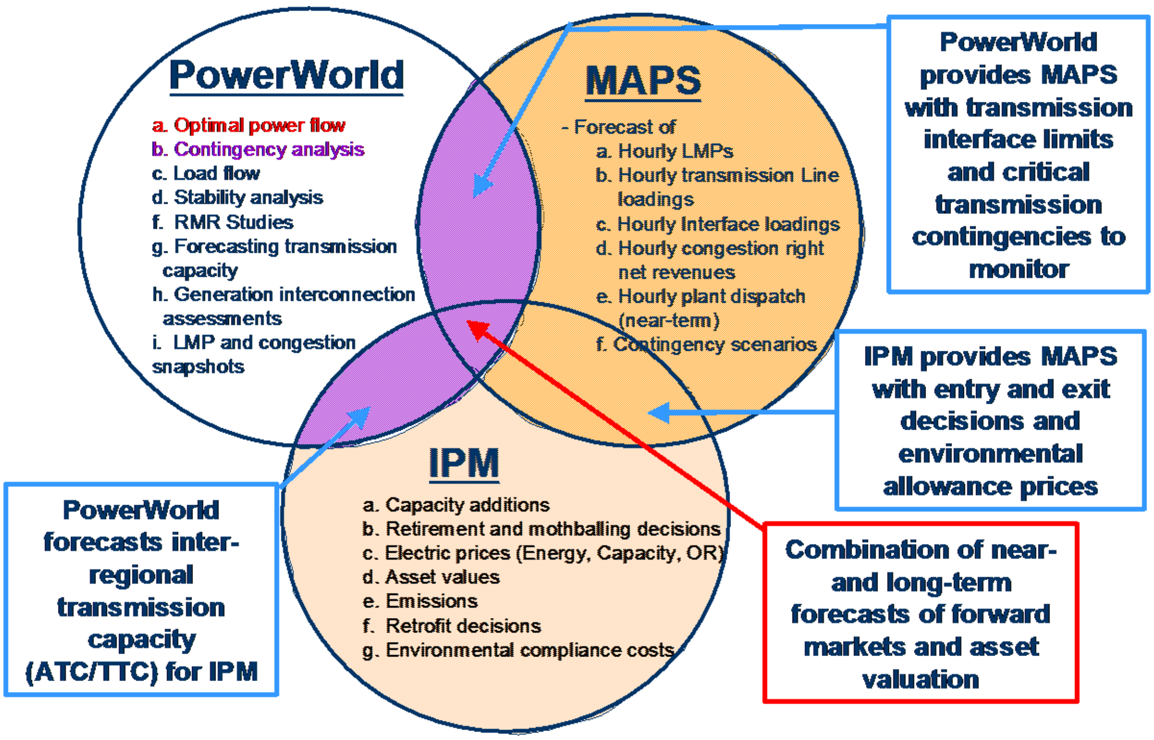


Figure 3: GMM Transmission Network



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

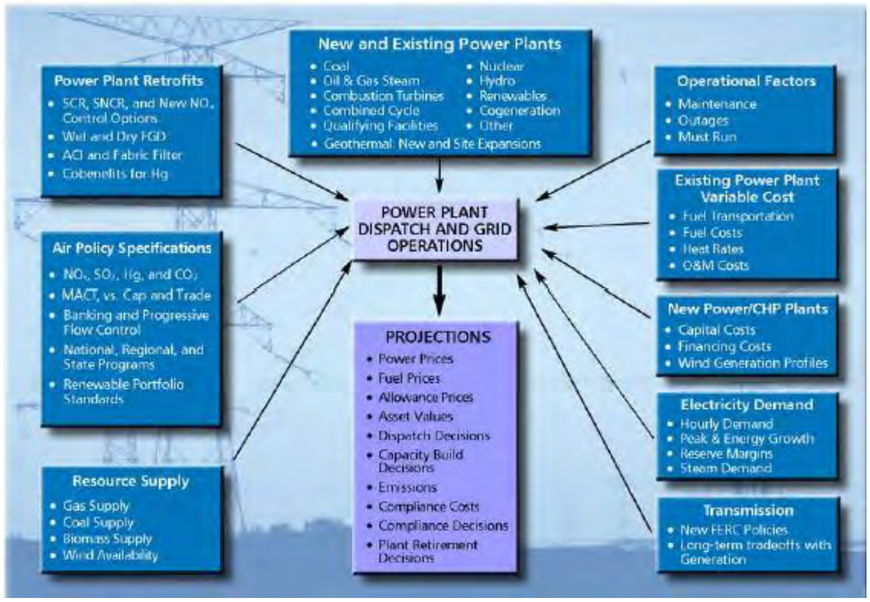
Figure 4: ICF Analytical Tools Focus on Specific Problems



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

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

Figure 5: IPM Framework



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

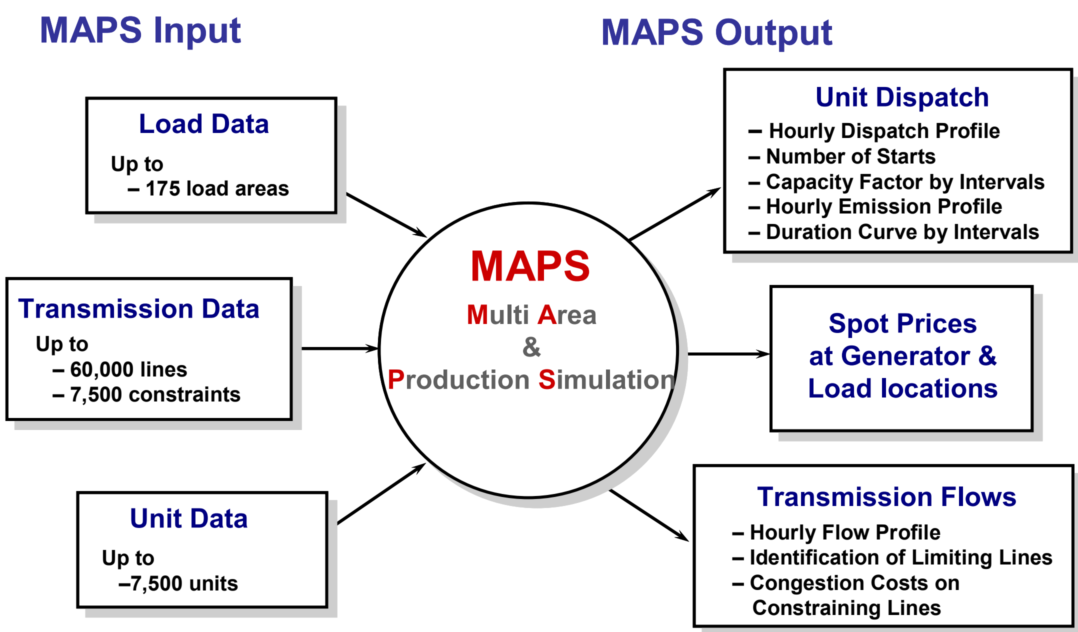
Outputs of IPM® include estimates of regional energy and capacity prices, optimal build patterns based on timing of need and available technology, unit dispatch, air emission changes, retrofit decisions, incremental electric power system costs (capital, FOM VOM), allowance prices for controlled pollutants,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

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

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

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

Figure 6: GEMAPS Framework



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