REPORT

Analysis of Alternative Winter Reliability Solutions for New England Energy Markets

Prepared for:
GDF SUEZ Energy North America,

Prepared by:
Energyzt Advisors, LLC

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For further information, please contact:

Tanya Bodell, Executive Director: Tanya.Bodell@energyzt.com

Zander Arkin, Senior Managing Director: Zander.Arkin@energyzt.com

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EXECUTIVE SUMMARY

In New England, significant discussion and analysis has occurred in recent years regarding the reliability of electricity and natural gas markets in the winter. The winters of 2012/13 and 2013/14 experienced extreme weather and a series of transient infrastructure and commercial conditions that caused natural gas prices to soar, establishing new levels of natural gas basis differentials, along with corresponding increases in electricity prices.

In competitive energy markets, such as those that exist in New England, high prices generally indicate a shortage of supply for given demand levels. In keeping with this assumption, certain market participants have advocated for extraordinary government intervention to mandate regulated electric ratepayer funding of a new natural gas pipeline, implicitly claiming that high prices are signaling a shortage of pipeline delivery capability and a failure of the market to respond appropriately. Some have gone as far as to claim that New England gas and electric reliability are at risk. These claims are unsupported.

The proposed electricity ratepayer funding of additional gas pipeline capacity is an expensive and dangerous proposition in terms of ratepayer cost and healthy market function in New England. Energyzt's review and analysis of recent events and future gas and electric market conditions in New England, embodied in this report, support the following conclusions:

1. **Existing infrastructure is more than adequate.** Existing pipeline, pipeline expansions already underway and other natural gas supply infrastructure is more than adequate to meet winter peaking needs. In fact, the electricity system has maintained required reserve margins during some of the most extreme conditions over the past three winters despite numerous force majeure challenges. The issue is not lack of infrastructure, but insufficient commercial contracts to access existing energy

infrastructure.[1] Winter 2014/15 illustrates the positive impact of utilizing existing infrastructure.

2. **Winter prices reflected a transient peaking problem.** High prices from the winters of 2012/13 and 2013/14 reflect a peaking problem and lack of commercial arrangements with existing infrastructure, not a baseload issue that justifies new pipeline capacity. High basis differentials for natural gas in New England during the past three winters occurred during only a few of the highest peak demand days of the year (when incremental delivery infrastructure was available but had not been arranged for in advance to ensure commercial availability at a price certain).

3. **The market is responding with dual-fuel capability and LNG contracts.** This past winter 2014/15 has demonstrated the powerful ability of competitive natural gas and electricity markets to respond to price signals. Dual-fuel units providing up to 6,000 MW (700 to 900 million cubic feet per day) of gas demand reduction on an as-needed basis already have been recommissioned, and gas distribution companies have entered into new long-term contracts for LNG imports. As a result, realized basis differentials this past winter were roughly half of what they were in Winter 2013/14 and are expected to reduce even further as existing infrastructure is contracted and otherwise made available. ISO-NE's Pay-for-Performance program also could motivate innovative, market-based solutions to winter reliability, including potential conversion of additional gas-fired units to dual-fuel capability.

4. **New Pipeline Capacity already is being built.** The Atlantic Bridge Project, Spectra's Algonquin Incremental Market (AIM) Project, and other expansion projects are expected to increase pipeline delivery capacity by around 600 million cubic feet per day by winter 2017/18. This new

[1] In addition to this report, Energyzt performed an analysis focused explicitly on the adequacy of existing infrastructure on behalf of the New England Power Generator's Association, "Report: Winter Reliability Analysis of New England Energy Markets," October 2014, http://nepga.org/14/10/energyzt-report-on-winter-reliability/

pipeline capacity needs to be included in any assessment of costs and benefits of an additional pipeline.

5. **Public policy does not support new pipeline infrastructure.** Federal and state policies are promoting non-gas-fired generation such as renewables, low load growth from energy efficiency and demand response, and market-based performance incentives in New England competitive capacity markets to ensure electric generation capacity is available when it is needed most. These programs are projected to flatten if not decrease natural gas consumption from the electric generation sector. Emerging technologies such as distributed generation and battery storage are likely to further moderate peak demand. Government intervention to build a new gas pipeline to supply future natural gas demand from the power sector is inconsistent with these programs.

6. **A new pipeline subsidized by electric ratepayers violates the beneficiary pays principle.** Given existing energy infrastructure, expansions already underway, and other market responses to winter peak prices, a new pipeline subsidized by electricity ratepayers will overserve the New England market, resulting in a glut of natural gas throughout the year that is likely to flow to markets outside of New England into Canada and overseas. This would leave New England ratepayers paying for the cost of building a new pipeline for twelve months of the year, and reselling back unused capacity at a lower rate for at least nine months to natural gas shippers selling into other markets.

The lowest cost and lowest risk way to meet power generation demand and reduce natural gas prices in the New England market in the near to medium term is to contract with existing infrastructure, including LNG imports and dual-fuel capability, that can provide peaking response at little to no capital cost and without ratepayer commitment. With existing infrastructure and projected needs over the next ten years, there is plenty of time to monitor how existing policy initiatives, infrastructure availability, market response and therefore new pipeline infrastructure needs evolve over the long-term. The solution is contracting, not construction.

1 INTRODUCTION

Natural gas delivery and electric utility reliability in New England has come under scrutiny given the past few unusually cold winters. As an increasing amount of the region's electric generating capacity relies on natural gas, there is an expressed concern among certain constituents that supply of natural gas is inadequate to meet existing and future power generation demand needs.

As a result of this concern, multiple proposals have been discussed, including an approach by the region's governors, to increase natural gas delivery capability into New England with a new natural gas pipeline. Rather than rely on private parties risking private capital in response to market forces, however, government proposals recommend using region-wide tariffs assessed on regulated electricity ratepayers to support large pipeline infrastructure investments or otherwise committing ratepayers regionally to fund those investments.[2] This would be a mistake.

Instead of mandating a new pipeline funded by electricity ratepayers or taxpayers, contracting to utilize existing infrastructure would be the more cost-effective and lower risk approach in the near term as announced projects to increase pipeline capacity funded through more traditional market-based funding mechanisms proceed.[3]

1.1 Purpose of report

Energyzt has been retained to review energy market conditions in New England and to compare the costs, benefits and market impacts of alternative proposals to

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[2] New England States Committee on Electricity, "Addressing New England's Energy Challenges," p. 23 (www.nescoe.com/uploads/ RegionalInfrastructure_NECouncil_30Jun2014.pdf accessed 8/14/14).

[3] Increasing use of existing infrastructure before committing ratepayers to significant capital costs is in keeping with prudent planning under vertical integration of investor owned utilities. Under NEESPLAN 4, the New England Electric System resource planning strategy emphasized the importance of the option value to ratepayers of avoiding long term fixed cost commitments.

address winter reliability. Alternatives to building a new natural gas pipeline include:

- Leveraging existing pipeline expansions currently underway in the region;

- Contracting with existing liquefied natural gas (LNG) infrastructure more effectively to meet short-term winter needs; and

- Utilizing existing gas-fired combined cycle units (CCGT) with dual-fuel (gas and oil) capability.

All of these alternatives are more cost-effective solutions than building a new natural gas pipeline funded by electricity ratepayers.

Also under consideration for reasons other than winter reliability, is development of a high-voltage transmission line from Canada to import hydroelectric energy into New England. This option could serve to diversify the fuel mix, but would not be an effective solution to winter reliability on a stand-alone basis as it would have a year-round impact and tend to displace oil-fired units operating on the margin. As a result, dual-fuel capability and LNG are cost-effective, flexible peaking solutions to a winter peaking problem.

1.2 Summary of conclusions

The conclusions supported by the analyses embodied in this report are summarized below:

1) **Energy infrastructure is adequate when more fully utilized:** Existing energy infrastructure in New England is more than adequate to meet winter peaking needs for the near to medium term and is the most cost-effective and economically efficient solution compared to building a new natural gas pipeline. High winter natural gas prices the past few years reflect a peaking problem caused by transient events combined with lack

of utilization of existing dual-fuel and natural gas infrastructure, not a lack of baseload pipeline delivery infrastructure.

2) **Electricity markets are not causing the shortfall:** Market responses to high prices in recent winters already have resulted in a significant reduction of electricity and natural gas prices. Reliability reserve margins have been met and maintained during the most extreme conditions in the power sector, indicating adequate power sector infrastructure. A number of programs already underway have made better use of existing power generation resources and natural gas supply, moderating power prices this past winter. Furthermore, public policy initiatives already in place are likely to result in negligible increase in natural gas-fired generation demand over the next decade. Both DOE projections and our own analysis indicate that, in the absence of a major policy shift, the demand for natural gas from the electric power sector is not driving the need for a new natural gas pipeline in New England.[4]

3) **Electricity ratepayers will not benefit:** So long as commercial contracts are in place to access existing gas and power infrastructure, in addition to incremental capacity expansion of existing pipelines already underway,[5] New England electricity ratepayers will achieve winter reliability at a normal and efficient price level. Forcing electricity ratepayers to fund a new pipeline will result in a glut of pipeline capacity in New England, likely leading to higher total costs to ratepayers and supporting the export of U.S. gas supplies from the Marcellus to foreign markets in Canada and overseas year-round.

[4] Public policy initiatives that artificially decrease variable energy prices (e.g., excess gas pipeline delivery capacity financed by long-term cross-industry commitments) could impact the resource mix. Increasing pipeline supply outside of market economics could financially strain non-gas-fired generation resources (e.g., nuclear), potentially accelerating their retirement. Subsidizing gas prices below competitive market levels also could increase the relative competitiveness of gas-fired generation, ironically increasing New England's reliance on natural gas.

[5] Incremental capacity expansions include the Atlantic Bridge Project, Spectra's Algonquin Incremental Market (AIM) Project, and other expansions. In addition, Northeast Energy Direct (NED) has announced that it is proceeding with building a new pipeline, with nearly half of the proposed capacity subscribed by local distribution companies.

The solution is to contract with existing energy infrastructure to provide winter peak solutions while market incentives and market-based programs already in place secure and diversify New England's energy supply.

2 WINTER RELIABILITY – IS THERE REALLY AN ISSUE?

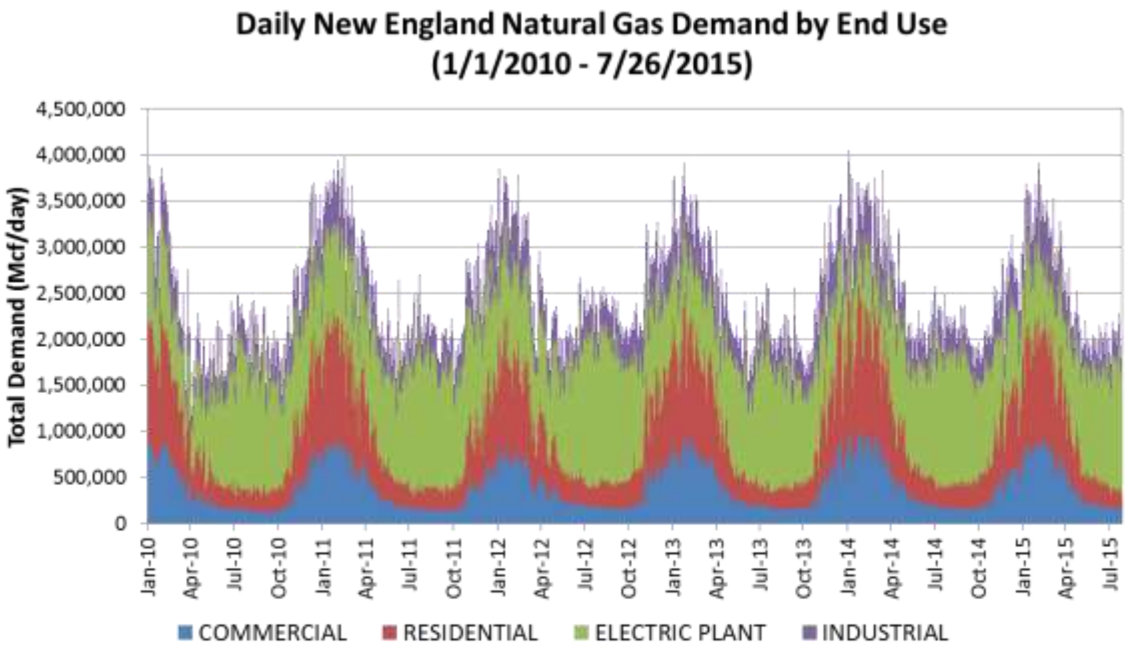
Before analyzing alternative solutions to a problem, it is prudent to understand the nature of the problem. This section describes the experience of the past three winters to identify: 1) the underlying cause of the perceived natural gas shortage; and 2) what high prices truly are signaling. Our conclusion is that high winter prices are indicative of a failure to more fully utilize existing energy infrastructure, and not an indicator of insufficient pipeline capacity. Existing energy infrastructure can be utilized more cost-effectively, especially given current world market prices for LNG and oil. Therefore, the appropriate remedy is to improve utilization of existing infrastructure, not commit electricity ratepayers to new capital investment.

2.1 Energy market background

New England generally enjoys a synergistic relationship between natural gas and electricity markets. Demand for natural gas peaks in the winter months as cold weather increases heating requirements while electric load peaks in the summer for cooling needs. The result is an ability to capitalize on otherwise underutilized assets when needed for each energy market to meet its peak demand needs.

Figure 1 plots natural gas demand by end use over the past five years, illustrating this relationship and three key points. First, although Winter 2013/14 shows higher peak demand spikes compared to prior winters, there is no discernable trend regarding growth in total demand for natural gas during the winter season. Second, demand spikes during Winter 2013/14 were driven by increases in residential requirements during cold snaps. Third, the power sector was able to provide swing demand in response to higher prices when required.

Figure 1: Natural gas demand in New England by end-use



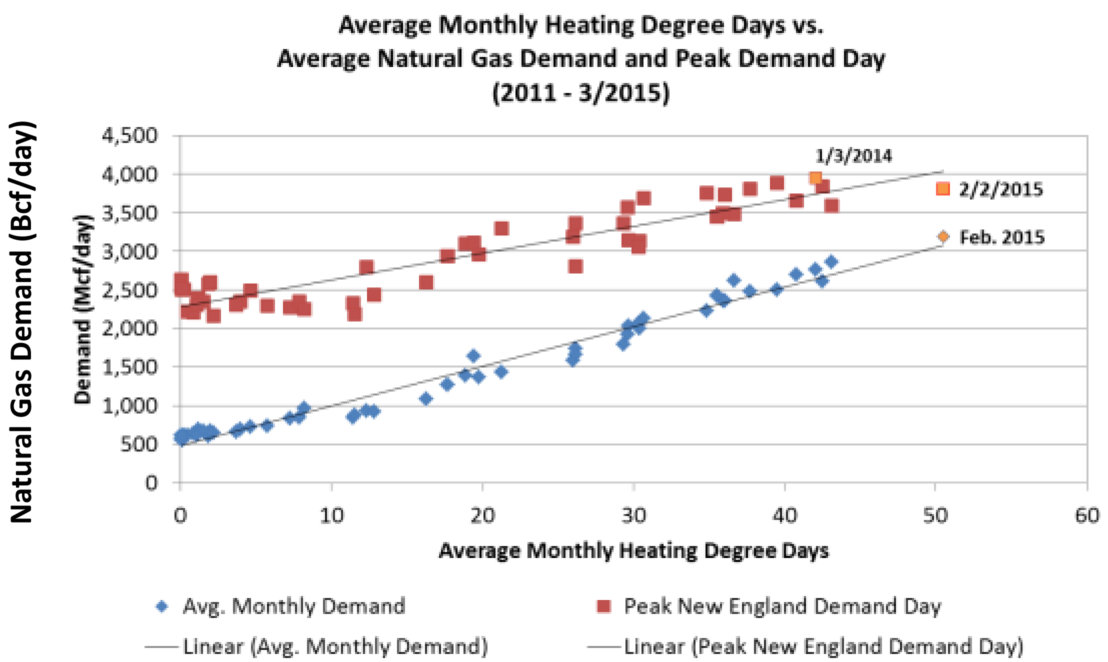
Source: EIA Natural Gas Monthly Report

This section elaborates on these key points in more detail below.

2.1.1 Natural gas demand peaks in the winter

In New England, natural gas is used for heating by residential and commercial customers and for process heat in industrial operations. These customers generally take firm service from local gas distribution companies ("LDCs") and LDCs plan their systems, including purchases of firm interstate gas pipeline capacity, to meet expected winter peak demand when temperatures cool and heating requirements rise.

Figure 2: Monthly peak and average gas demand in New England

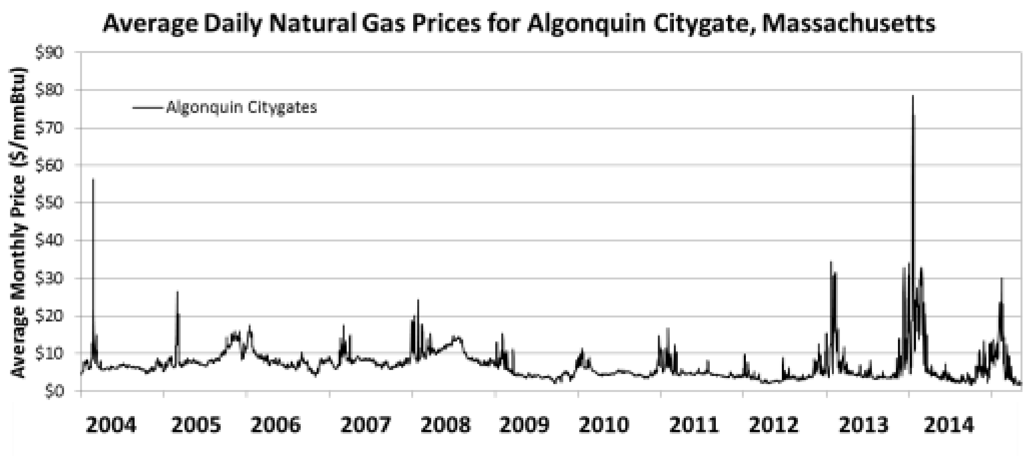


Source: Energyzt analysis of Ventyx, Energy Velocity Suite

As can be seen in Figure 2, there is a strong relationship between natural gas consumption by LDC customers and temperature as measured by heating degree days (i.e., the amount by which daily mean temperature falls below 65° F). As temperatures plummeted during the past three winters, (meaning a higher heating degree day value), demand for gas increased. January 3, 2014 established a new peak day for natural gas demand whereas average monthly demand for natural gas peaked in February 2015.

As a result, natural gas prices peak in the winter, indicating a winter peaking problem primarily during December through February, not a baseload issue (Figure 3).

Figure 3: Average daily natural gas prices in New England



Sources: Energyzt analysis of Ventyx Energy Velocity Suite

2.1.2 Demand for electricity peaks in the summer

Unlike natural gas demand for heating which peaks in the winter, electric power demand is more closely related to cooling needs and generally peaks on an annual basis during summer months. As a result, electric reliability tends to be a summer concern when reserve margins, the ratio of total capacity over peak demand, is tightest during peak demand hours. Shoulder months and summer periods correspond to relatively low natural gas demand, creating more than enough excess pipeline capacity and supply to meet natural gas-fired power generation needs.

ISO New England (ISO-NE) is responsible for meeting electric power demand and reserve requirements across the region's grid. It accomplishes these goals by scheduling and then dispatching generating capacity based on individual generator bids in competitive power markets. ISO-NE also is responsible for scheduling imports and exports of power across the region.

ISO-NE ensures long-term reliability by conducting an annual forward capacity market ("FCM") in which generators and dispatchable load are paid to accept a Capacity Supply Obligation ("CSO"). Market participants with a CSO are required to maintain and operate their facilities in order to be able to provide power (or reduce demand) when called upon by ISO-NE. There is a system of penalties if parties are unable to meet their CSO. In addition to penalties, ISO-NE is implementing positive incentives in the form of a "Pay-for-Performance" program as part of the FCM starting in June 2018. The FCM therefore will provide a market-based mechanism, in addition to market-based energy prices, to ensure that generation capacity and load response are available when most needed (e.g., during extreme weather conditions).

The seasonal differential between the natural gas demand peak and the electricity peak tends to mitigate supply risk as winter peak generally represents a lower level of demand for electric power and therefore lower gas-fired generation requirements. Consequently, most natural gas fired generators do not purchase long-term firm capacity on pipelines. Instead, they rely on firm capacity that is available on the secondary market or non-firm capacity which is generally abundant in the summer when electric demand peaks to its highest levels. However, non-firm pipeline capacity can be subject to curtailment in winter when the opportunity cost of not being able to run on pipeline gas generally has been lower. Even if higher electric energy prices emerge in the winter, gas units at the margin generally only recover their variable costs through energy prices. The decision to incur additional fixed costs to improve their winter peaking gas supply is only justified where the cost is exceeded by projected energy margin opportunity.[6]

Starting in June 2018, the Pay-for-Performance reforms to the FCM will improve incentives for fuel supply certainty during winter peaking periods. Natural gas delivery curtailments that occurred the past three winters to non-firm delivery customers, such as gas-fired generators, should be less likely to occur with a

[6] The ISO-NE winter reliability program originally was designed around a subsidy mechanism to cover seasonal oil inventory costs. While the program added an LNG component in Winter 2014/15, the program is not designed to access fuel sources other than oil, thereby distorting incentives to access other existing energy infrastructure options. This should be remedied with the market-based Pay-for-Performance program.

market-based approach to incentivize procurement of winter peaking fuel supply.

2.2 Winter experiences the past three years

2.2.1 Winter 2012/13 caught the market unprepared

Following the mild winter of the year before, Winter 2012/13 was much colder. Although actual peak load was less than the 50/50 forecast,[7] sustained cold weather tried the system and highlighted areas where the markets were unprepared.

In particular, ISO-NE identified five areas of reliability concerns created by the growing dependence on natural gas-fired generation:[8]

- **Nonfirm transportation:** Lack of firm fuel arrangements for delivery to gas-fired generators could and did result in curtailment.

- **Imperfect coordination:** Difference in timing between gas and electricity markets limited response to changing power system conditions.

- **Lack of Readiness by oil-fired generators:** Infrequent operations by oil-fired generators resulted in low oil inventories and operational challenges.

- **Pipeline Constraints:** Shifts in natural gas flows challenged gas delivery.

[7] Kirby, K., Vice President, Market Operations, ISO-NE, "ISO New England Winter Operational Experiences and Regional Actions," Presentation to FERC, May 16, 2013,

http://www.ferc.gov/CalendarFiles/20130516134342-2-ISO-NE.pdf

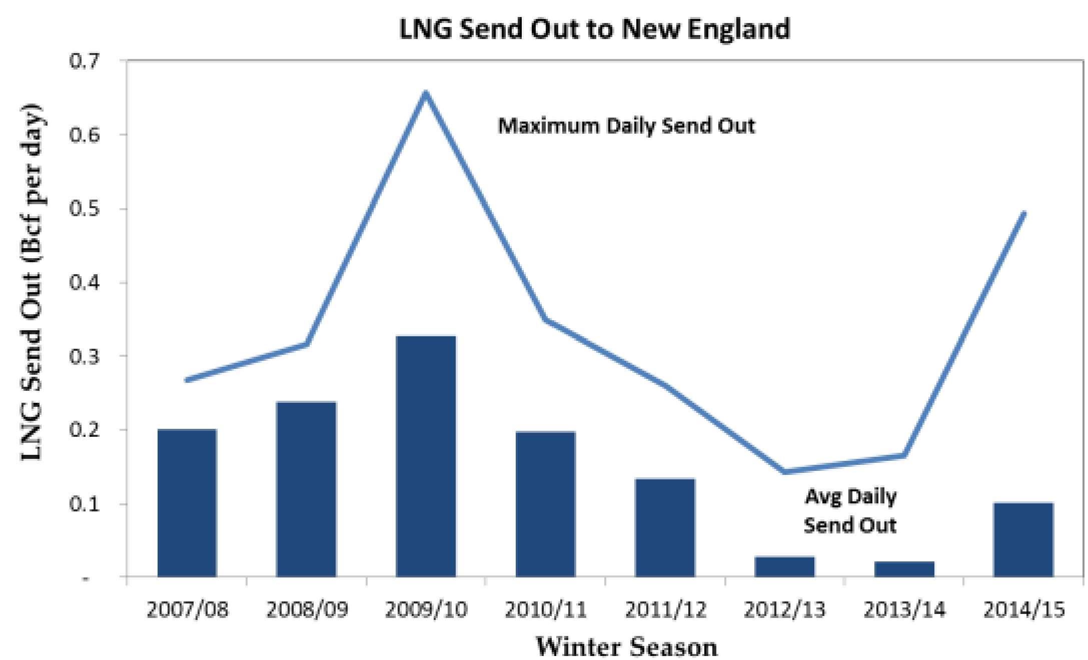
[8] Ibid., p. 8.

- **Pipeline Outages:** Availability of gas-fired generation could be jeopardized during pipeline outages.

It is important to note that none of these stated reliability concerns mandate the need for a new pipeline, and most can be addressed in more cost-effective ways.

Pipeline constraints and pipeline outages, for example, occurred during the Winter 2012/13 as LNG contracts rolling off in 2012 creating a shift in natural gas supply. Although LNG deliveries directly to Mystic Generating Station and Boston Gas continued, LNG sendout into gas pipelines from Everett fell from an average of 0.2 to 0.3 billion cubic feet per day to less than 0.01 billion cubic feet per day before rising back to historic levels last winter (Figure 4).

Figure 4: LNG pipeline supply to New England



Source: Energyzt analysis, Ventyx Energy Velocity Suite

Lower LNG supply from the east impacted power markets in two ways. First, there was a "shift in natural gas flows" with not enough natural gas flowing into the pipelines from the east, causing a lack of pressure and compression challenge as gas deliveries progressed from supply originating in the west. Second, lower LNG supply from the east eliminated the diversification of fuel supply that New England historically has enjoyed, causing pipeline operational issues to have a greater impact on the system. Although high prices had a limited impact on LNG imports that had not already been reserved, natural gas did flow from Canadian sources, mitigating some of the challenges with bringing in gas from the west.

Lack of coordination between natural gas and electricity markets also created challenges. Differences in the timing of natural gas elections versus energy market bid schedules meant that natural gas-fired generators could not respond in a timely way to ISO-NE dispatch requests. ISO-NE already has addressed this issue by shifting the day-ahead market timing to be earlier[9] and engaging in greater information sharing with gas pipelines.[10]

In addition, dual-fuel capability in New England was not ready to run. High oil prices combined with lack of need during prior winters encouraged plant owners to sell the oil out of their tanks or otherwise minimize tank inventory, limiting supply when most needed and most lucrative. The lower LNG supply, limited oil inventory, and a number of other short-term supply constraints created high prices in Winter 2012/13.

[9] Docket No. ER13-895, effective May 23, 2013. In April 2015, FERC issued a final order that declined to adopt the NOPR proposal to move the start of the gas day earlier by five hours concluding that the record in the proceeding did not justify changing the start time, but recognizing that several regional efforts address the misalignment. 151FERC ¶ 61,049, Docket No. RM14-2-000; Order No. 809, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, Issued April 16, 2015. http://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf

[10] Docket No. ER13-356, effective January 24, 2013 to April 30, 2013, although not invoked.

Lastly, gas-fired generators had not contracted for firm gas supply, for reasons that already have been discussed.[11] The lack of firm natural gas supply and inconsistency between nonfirm supplies and bidding schedules into New England's power markets forced many of them to be unavailable during high priced hours of production.[12] ISO-NE has developed an interim performance incentive program to motivate generating capacity resources to deliver when required, with planned implementation of a market-based Pay-for-Performance program in 2018.[13]

2.2.2 Winter 2013/14 had a number of transient events impacting supply

Having learned its lesson from events during Winter 2012/13, energy markets were better prepared. The ISO-New England Winter Reliability Initiative supported fuel contracting to be available at dual-fuel and oil units when needed and a number of market rules with the sole purposes of creating consistency between natural gas and electricity markets were underway.[14]

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[11] In addition, FERC found that ISO-NE would still have to pay capacity payments to gas-fired generators even when nonfirm gas was not available. FERC Order on Rehearing, Docket No. EL13-66-001, new England Power Generators Association, Inc. v. ISO New England Inc., December 6, 2013, http://www.ferc.gov/CalendarFiles/20131206161403-EL13-66-001.pdf

[12] It is noteworthy that even had some of these gas-fired generators held firm transportation, a real-time dispatch by ISO-NE may have left them unable to access supply since the dispatch would be well after the interday or evening nomination cycle and pipelines would not have packed the pipe to support those withdrawals, illustrating a potential impact of gas-electric coordination issues.

[13] ISO-NE, frustrated that FCM generation capacity resources were not available when most needed, embarked on a Winter Reliability program for the next winter with the longer term goal of establishing appropriate market mechanisms to encourage natural gas-fired generators to do whatever is required to be available and ready to perform, including contracting to ensure reliable delivery of required gas supply. ISO-NE modified the "Failure-to-Reserve" penalty rate to reflect replacement costs and modified the trigger for the "Failure-to-Activate" penalty. A different program was developed for Winter 2013/14 and Winter 2014/15. Over the longer term, ISO-NE is developing a market-based solution in accordance with FERC Order ER14-2407.

[14] The first Winter Reliability Program, implemented during winter 2013/14, provided incentives for dual-fuel units and oil-fired generators to store more fuel that could be accessed in the event of a natural gas shortage.

Yet a number of short-term emergency situations tested the markets:

- **Extreme Weather:** The polar vortex swirled into the entire eastern part of the United States, freezing most of the states east of the Mississippi from Canada to Texas. Normally warm-weather states were caught without adequate infrastructure to deal with record lows and snow.

- **Problems in Other Jurisdictions:** System emergencies in neighboring jurisdictions (e.g., Quebec and PJM) created extreme but temporary electricity import disruption due to frozen coal piles and general unpreparedness of energy infrastructure to respond to extreme cold.[15]

- **Equipment Failure:** Natural gas pipeline equipment failure (e.g., Texas Eastern Pipeline) decreased natural gas deliveries into the northeast and interrupted non-firm supply.

- **Market Coordination:** Lack of coordinated electricity and natural gas scheduling protocols precluded natural gas-fired units from accessing nonfirm gas supplies that were released in time for real-time markets.

- **LNG Commercial Contracts for Supply:** LNG continued to be contracted at lower levels than historic sendout, including supply to Mystic and Boston Gas system under existing contracts continued, albeit at lower levels.

Yet, despite a number of constraining conditions, wholesale electricity market reserve margins were never violated due to lack of natural gas supply. Furthermore, all firm natural gas delivery obligations were met and there was no interruption of electric service.

[15] Neighboring jurisdictions such as PJM also have the same winter peak issues as New England. As the experience with imports from Hydro-Québec showed in December 2013 when power flows were curtailed in order to meet Québec reserve margins and in December 2014 when a transmission outage limited power flows into New England, relying on long-distance supply has its own risks.

Events during January 7, 2014, the day experiencing the tightest reserve margins, illustrate how short-term issues constrained the system, not a baseload shortage of natural gas delivery infrastructure. On that day, the following occurred:[16]

- **Generation Capacity was called.** ISO-NE called upon generators representing a total CSO of 30,703 MW. In addition to the CSO capacity, around 2,980 MW of installed capacity was available, resulting in a total capacity in the region of 33,683 MW.

- **Units were unavailable.** From this total, ISO-NE reports that 4,677 MW were unavailable due to both unit outages and the unavailability of gas. This total is comprised in part by 1,500 to 1,700 MW of generation with outages and 1,000 MW of reductions to seasonal claimed capacity.[17] Additionally, there were up to 1,280 MW of gas fired generation that could not confirm in a timely manner whether they would be able to procure sufficient gas for operations -- many of these units "later called and advised they were available."[18]

- **Commitment was not optimized.** There were an additional 5,921 MW of installed capacity that was not available on peak because of start time constraints, meaning that this capacity had not been scheduled in advance by ISO-NE. Low day-ahead demand clearing pushed some of the unit commitment needed to meet actual peak to after the day-ahead process, limiting ISO-NE to generation with lead times less than 12 hours. Still, net of even these outages and scheduling constraints, a total of 23,085 MW of in-region capacity was available to serve peak demand.

[16] ISO-NE, "January 2014 FERC Data Request," p. 1, http://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2014/iso_ne_response_ferc_data_request_january_2014.pdf .

It is important to note that January 7th was not the coldest day nor the peak demand for natural gas. However, it did occur during a very cold period that, according to ISO-NE, was among the coldest 5% of all days over the prior twenty years.

[17] ISO-NE, "January 2014 FERC Data Request," p. 10.

[18] ISO-NE, "January 2014 FERC Data Request," p. 2.

- **Net imports were negligible.** In its day ahead planning, ISO-NE had expected to import 1,100 MW from New York in addition to approximately 2,200 MW from Canada.[19] During the operating day, not only did New England not receive these imports, it actually exported 1,480 MW to New York, of which 500 MW was emergency power to PJM during eight of the peak hours that day. During the peak hour, ISO-NE reports net imports of 752 MW. Combining in-region resources with net imports produces total available capacity of 23,836 MW.

- **Reserve margins were met.** ISO-NE load during the peak hour was 21,432 MW. This left 2,404 MW of capacity available for required reserves. Generators were dispatched to meet this load and to supply a required reserve margin of 2,360 MW to provide contingency protection (i.e., operating reserves). This reserve capacity was either synchronized or capable of being synchronized quickly in the event that a significant outage of a generator or transmission tie line had occurred.[20]

The net result was that ISO-NE was able to meet its reliability obligations (load and reserves) with 44 MW of surplus capacity. At first glance this might appear to be a tight margin. However, ISO-NE also supplied 500 MW in emergency sales to PJM and had approximately 6,000 MW of capacity that had not been scheduled for dispatch, in part due to the expected imports totaling 2,600 MW more than what was received on net.

During the winter day in 2014 with the tightest reserve margins, reliability was maintained and emergency exports from New England into PJM were delivered. Basis differentials and delivered gas prices were, however, still very high reflecting lower levels of contracting with existing energy infrastructure.

[19] ISO-NE, Daily Capacity Status worksheet (http://www.iso-ne.com/sys_ops/mornrpt/daily_capacity_status.xls accessed 8/14/14)

[20] The calculation of the reserves required in any particular hour depends on system conditions since it is meant to cover capacity that would be required if the largest transmission or generation contingencies were to occur.

2.2.3 Winter 2014/15 experienced significant market response

The market was better prepared for Winter 2014/15.[21] As measured by heating degree days, this winter was more extreme than the prior two and yet emergency events did not occur and the market was prepared to utilize existing energy infrastructure much more effectively:

- **LNG Contracts:** Aside from its Mystic and Boston Gas system commitments, LNG sendout increased to around half of its historic levels.[22]

- **Dual-fuel units:** The ISO-NE Winter Reliability program ensured dual-fuel capability was fueled and available, supplying nearly 1 million MWh of secondary fuel generation in lieu of gas consumption.[23]

- **Natural gas/electricity coordination:** Market rule changes to better coordinate the natural gas and electricity markets were in place.

- **Oil prices had fallen:** Compared to the previous winters when oil prices were at around $100 per barrel, oil prices had fallen to around $60 per barrel, offering a lower cost alternative making oil-fired generation more economic than natural gas in certain hours.

As a result, Winter 2014/15 experienced basis differentials at half the levels of the prior two winters. Many of the temporary commercial and physical issues from the previous two winters had been resolved. Market price signals, combined

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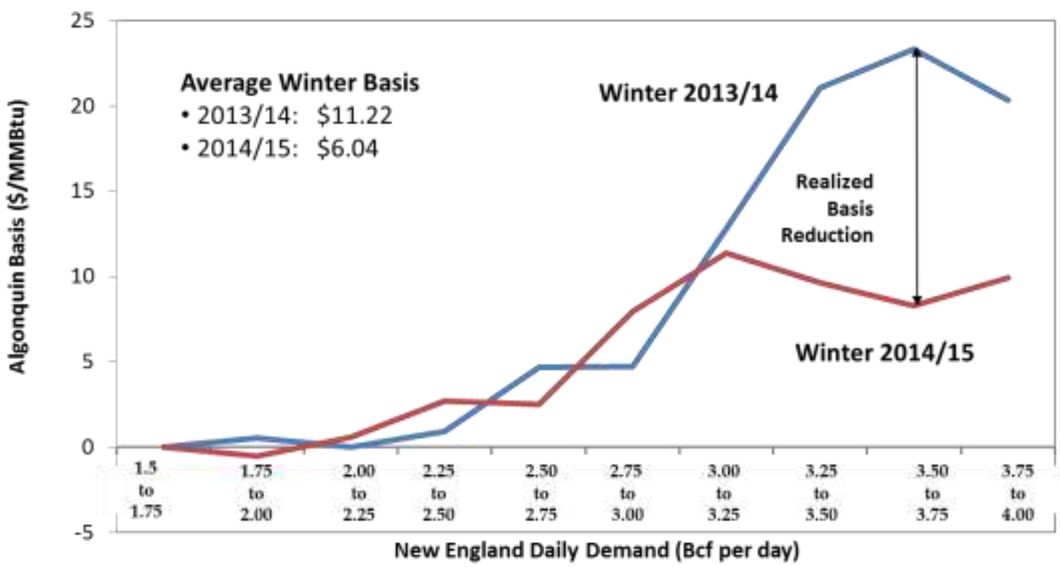
[21] ISO News, "New England power system performed well through winter 2014/15," April 7, 2015, http://isonewswire.com/updates/2015/4/7/new-england-power-system-performed-well-through-winter-20142.html

[22] Merchant generator interest in LNG contracting is likely to increase when the Pay-for-Performance reforms to FCM deliveries commence in Winter 2018/19, the first winter that will not have an administrative winter reliability program focused on oil inventories.

[23] ISO-NE modified its 2013/14 Winter Reliability program to address reliability concerns during cold weather conditions. The program provided guaranteed payments for fuel that was not used by the end of the season, encouraging oil and dual-fuel generators to increase oil inventories, for natural-gas-fired generators to contract for liquefied natural gas to augment pipeline gas, and for new demand-response resources to be available. The program enjoyed significant participation by generators.

with the ISO-NE Winter Reliability Programs, had caused market participants to begin to increase their contracted fuel supplies and the availability of existing infrastructure. Figure 5 illustrates the fall in basis differentials between Winter 2013/14 and this past year.[24]

Figure 5: Difference between basis differentials for daily demand levels



Source: Energyzt analysis, Ventyx Energy Velocity Suite

This chart illustrates the benefits of using existing infrastructure without the requirement of any upfront investment. Contracting for delivery using existing energy infrastructure reduced basis differentials by nearly 50 percent. This is nearly equivalent to the assumed basis reductions driving the $250 million in benefits claimed by a separate study in early 2015 from the addition of 500 million cubic feet per day of new pipeline capacity.[25] As shown by historic

[24] Another analysis issued by ISO Newswire tells a similarly compelling story. "Wholesale electricity prices and demand in New England, April 7, 2015, http://isonewswire.com/updates/2015/4/7/wholesale-electricity-prices-and-demand-in-new-england.html

[25] ICF International, Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England, prepared for Eversource Energy and Spectra Energy, February 18, 2015,

experience, contracting with existing infrastructure can realize benefits equivalent to a new natural gas pipeline without the upfront capital investment.

Existing infrastructure and competitive alternatives were able to meet New England's winter reliability needs with minimal natural gas price volatility despite record-setting cold temperatures and snowfall. A mere 50 percent of historic average LNG flows into New England markets and the dispatch of duel-fuel and oil units maintained required reserve margins and reduced gas prices and volatility by half.

Going forward, reactivated generation capacity, market-based incentives under development by ISO-NE, lower oil prices and new LNG contracts[26] will cap New England gas prices and basis differentials. Referring to a winter when existing infrastructure was caught unprepared or experienced a number of transient events lead to a gross overestimate of potential benefits of new infrastructure investment.

3 ALTERNATIVE SOLUTIONS TO WINTER RELIABILITY

This section builds off the historic analysis above to describe alternative solutions to addressing winter reliability, including the following:

1) New pipeline capacity
2) LNG imports
3) Dual-fuel capability
4) Canadian imports

http://accessnortheastenergy.com/wp-content/uploads/2015/02/ICF-Report-on-Access-Northeast-Project.pdf

This study also overstates potential benefits because it did not consider proposed pipeline expansions, dual-fuel capability and LNG imports in its projections.

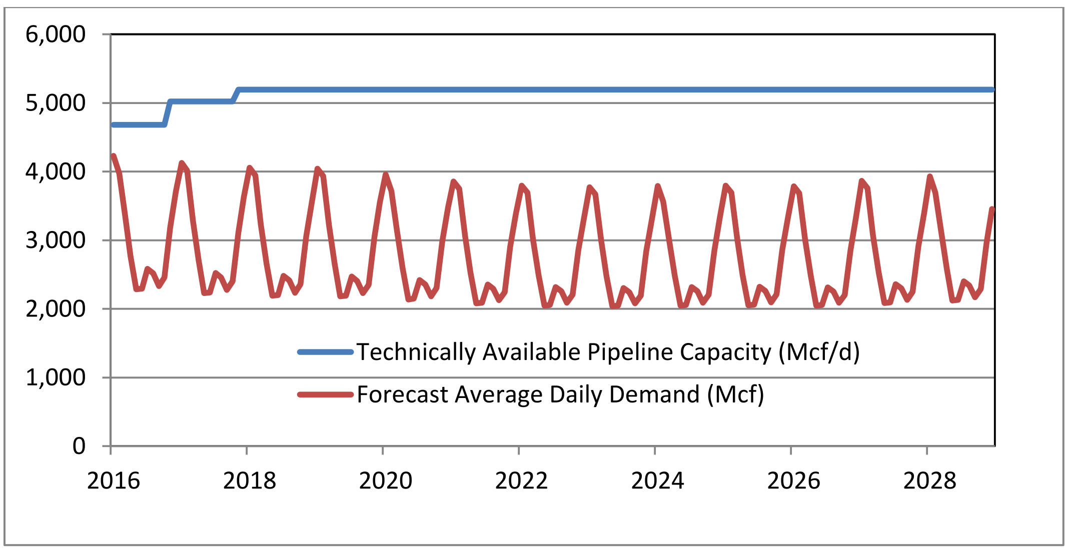
[26] Fitzgerald, J., "Distrigas says fuel deals should prevent future gas shortages," The Boston Globe, May 11, 2015, https://www.bostonglobe.com/business/2015/05/10/distrigas-inks-big-lng-deals/guafPlHwoFG4bhENhaERYK/story.html

The next section describes our analysis of the costs and benefits of dual-fuel capability and Canadian imports via a new HVDC transmission line.

3.1 Natural gas delivery infrastructure is sufficient

Current and planned pipeline capacity into New England is more than sufficient to supply New England's gas demand reliably for the foreseeable future through 2030.

Figure 6: Demand for natural gas in New England vs. pipeline capacity



Source: Energyzt analysis of IEA AEO 2015, Ventyx

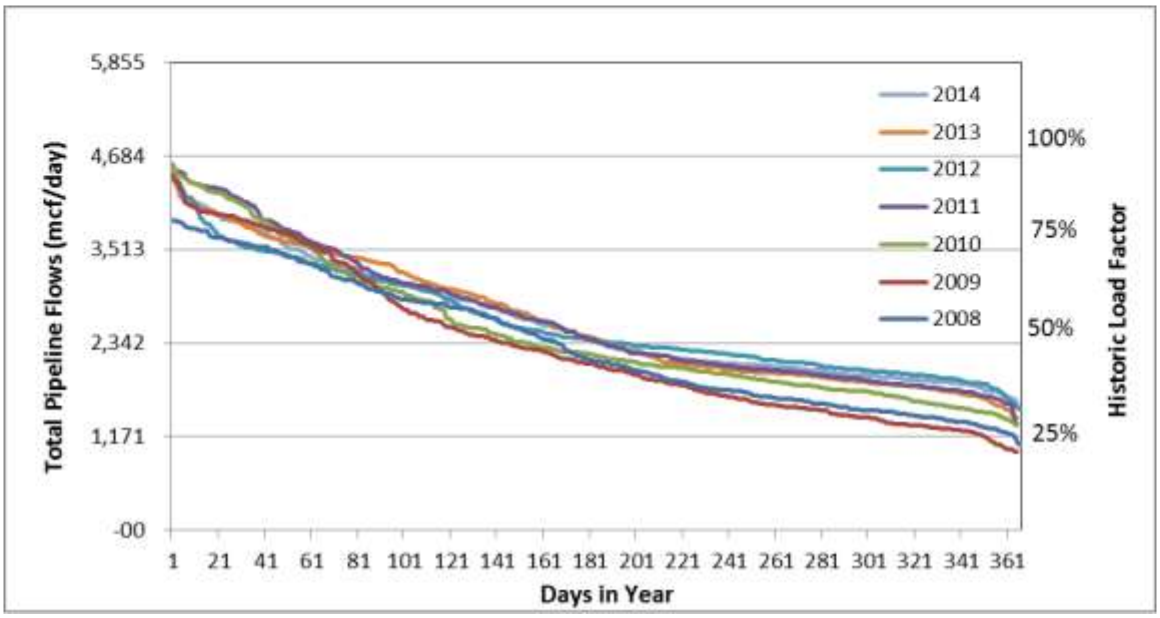
Figure 6 shows the EIA forecasted demand versus pipeline capacity in New England, including around 600 million cubic feet per day of additions scheduled to come online by November 2017 from the AIM, Atlantic Bridge Project, and other expansions.[27] During average daily demand conditions, there is no need for new pipeline capacity, even during winter months. Any need for new gas

[27] AIM proposes around 340 million cubic feet per day, Atlantic Bridge would expand delivery capacity by around 200 million cubic feet per day, and the CT Expansion Project would add around 70 million cubic feet per day

delivery capability to meet winter reliability issues is a peaking issue, not a baseload problem.

Similarly, peak demand can be and generally is met by existing pipeline capacity. Figure 7 plots the historic daily natural gas flows in New England from highest to lowest by calendar year. Since 2008, total flows peaked in 2011 when natural gas prices were the lowest then fell in 2012 and 2013 when prices increased.

Figure 7: Pipeline capacity load duration curve



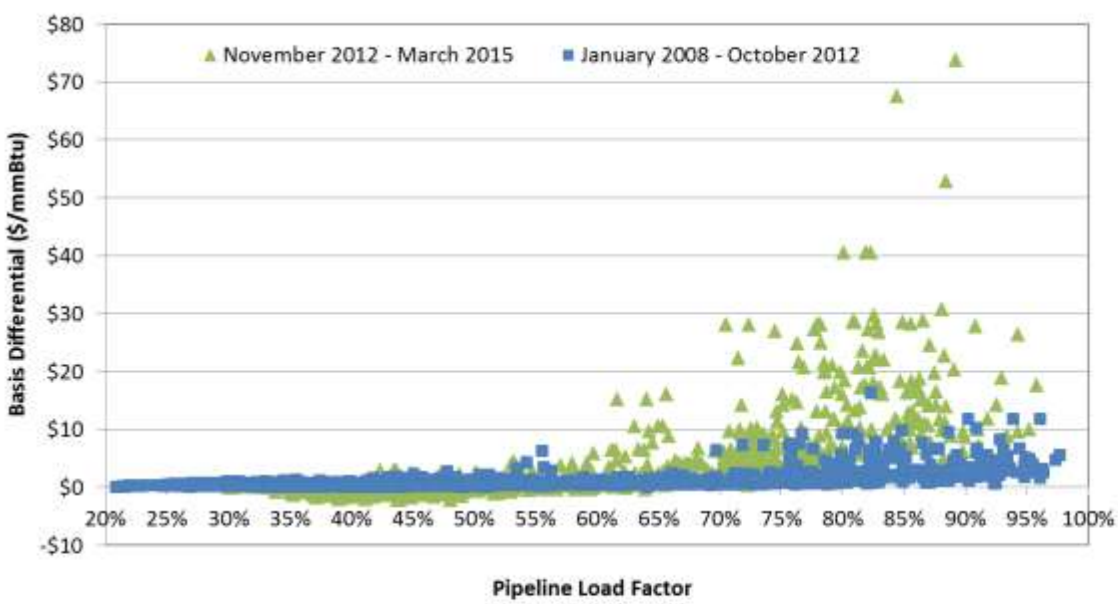
Source: Energyzt analysis of IEA AEO 2015, Ventyx

More importantly, however, the pattern of the flows has changed only slightly and in a way that does not support the need for new pipeline capacity. Peak flows hit a height during the mild winter 2010/11 when gas prices were at their lowest levels. Since then, the load duration curve has flattened with greater usage occurring when pipeline capacity factors are less than 50%, with plenty of room for growth. Otherwise, the extreme winter months show the same or lower natural gas demand during the peak periods when capacity factors exceed 75 percent as in 2008 to 2011.

The past seven years of pipeline flows do not indicate baseload growth that would support a new gas pipeline beyond the expansions currently underway.

That said, the past three winters have experienced unprecedented peaks in basis differentials and pricing (Figure 8). The automatic assumption is that high price signals are indicating the need for new infrastructure. Not in this case.

Figure 8: Natural gas basis differentials in New England



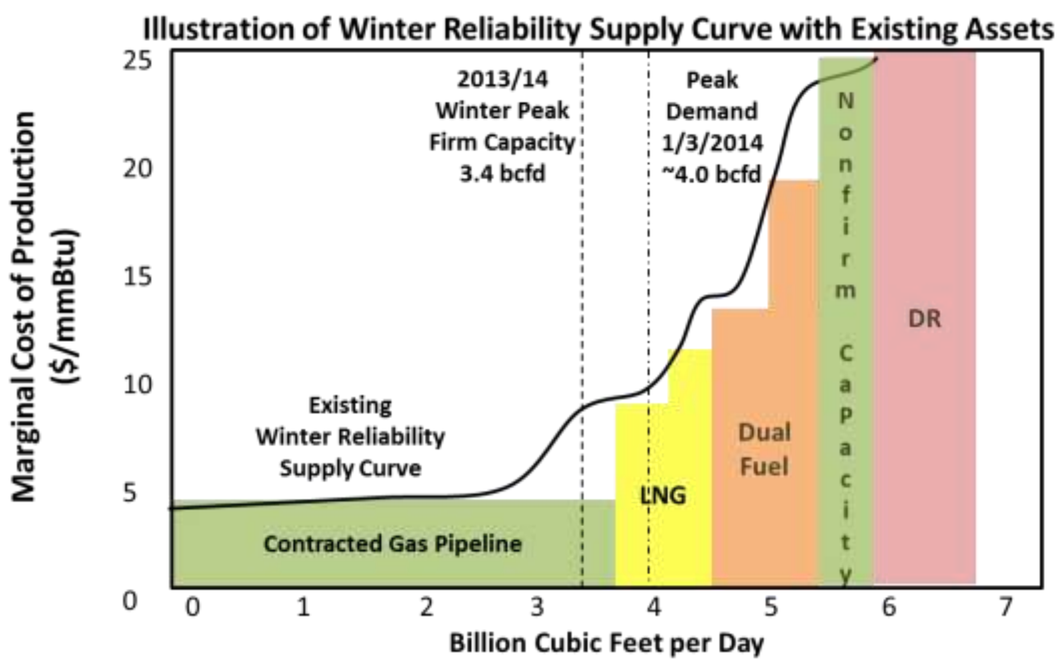
Source: Energyzt analysis of IEA AEO 2015, Ventyx

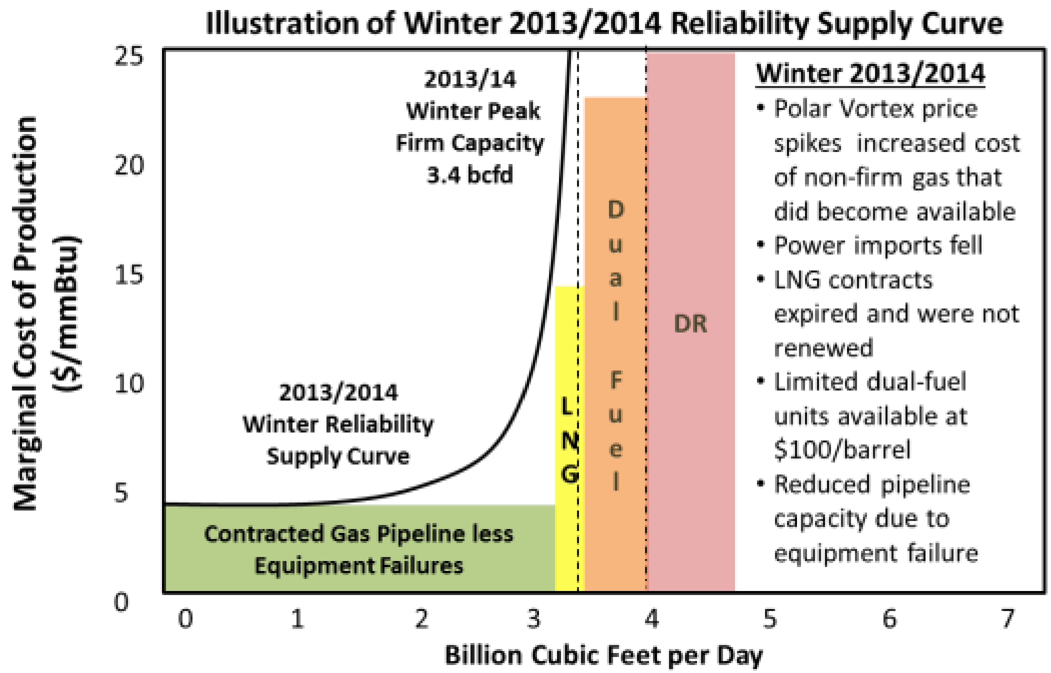
When load factors exceeded 65% the past three winters, basis differentials experienced significant volatility. As already mentioned, this volatility can be directly attributed to several factors other than lack of natural gas pipeline capacity which, for the most part, has been utilized at the same levels as the 2008 to 2011 period. Indeed, pipeline load factor explains only about half of the variation in historic pricing.

Another trend has been occurring in basis differentials during periods when load factors are between 25% and 65% (which is the vast majority of the time). Negative basis differentials actually have increased during the past three years, indicating more than adequate pipeline capacity during the non-winter months to bring New England natural gas prices in alignment with Marcellus production, and reiterating that this is a winter peaking problem.

Other factors have driven the cost of delivered gas in New England to new levels – not a lack of pipeline capacity. As already discussed, these factors include the underutilized LNG sendout capability, initially limited fuel switching capability, electricity import constraints and pipeline compression equipment failures.

Figure 9: Illustration of winter reliability supply curve and 2013/14 winter





Source: Energyzt analysis

Figure 9 illustrates the winter reliability supply curve under normal conditions utilizing existing energy infrastructure and during Winter 2013/14. Under normal conditions, there is more than enough natural gas pipeline capacity to meet peak firm delivery commitments of 3.4 per day and even the maximum demand that occurred on January 3, 2014 at average natural gas prices of around $10 per mmBtu. LNG and dual-fuel capability provide incremental peaking resources, which tend to be less expensive than nonfirm pipeline delivery of gas supply during super winter peaks when natural gas prices spike to above oil prices.

During peak days in Winter 2013/14, however, the Polar Vortex increased LDC demand for natural gas to new highs, LNG deliveries were reduced, and despite the ISO-NE Winter Reliability program, not all dual-fuel units were available for commitment. Furthermore, the pipelines ceased nonfirm contract deliveries. Prices increased during those periods to above $20 per mmBtu on average, with daily prices peaking between $30 and $40.

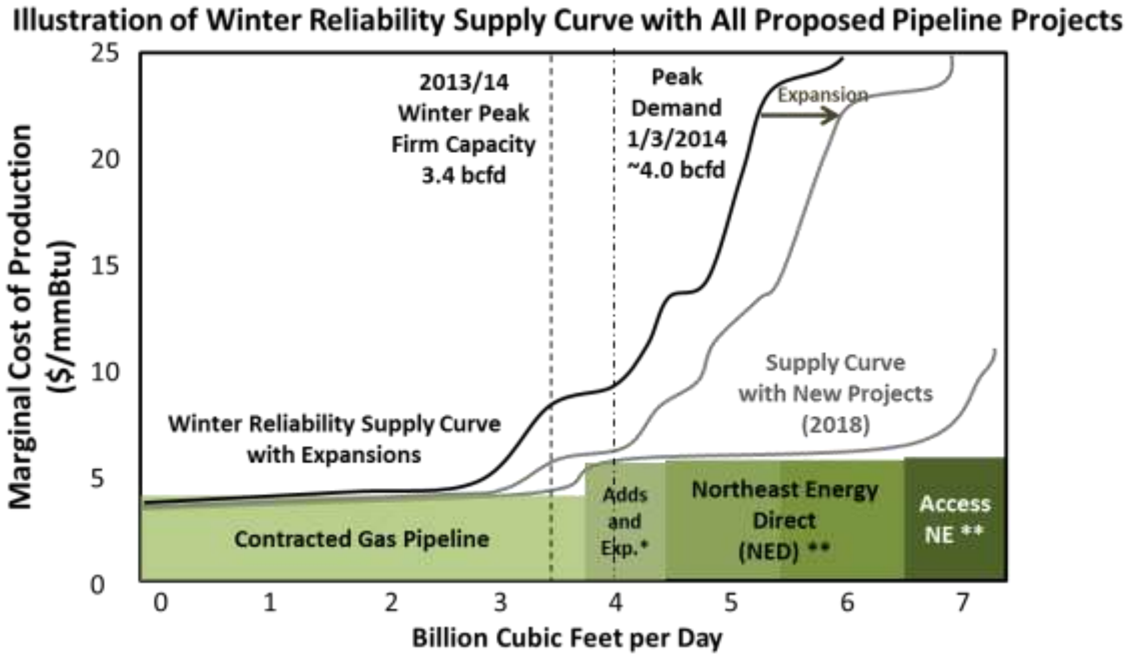
Although total demand for natural gas is increasing in the region, peak demand has not changed significantly according to natural gas flows into New England. Prices signals that occurred in New England during winter peak periods indicate the need for more contracting of existing infrastructure and resources rather than the need for new pipeline construction. There is more than enough existing energy infrastructure to meet winter peak needs.[28] Contracting existing infrastructure and resources provides a peaking solution to a peaking problem and can ensure reliable gas supply for the near term while decreasing basis differentials to historic levels, as was seen last winter.

In addition, there is incremental delivery capacity of 600 million cubic feet per day from the proposed expansions (i.e., Atlantic Bridge, AIM, and CT Expansion Project) coming online in 2016 through 2018. If this additional capacity is included, assuming historic levels of contracted energy delivery infrastructure, average basis differentials will shift downwards during winter months.

Additional delivery capacity from a new pipeline funded by electricity ratepayers will only serve to flood the market with natural gas, creating an uneconomic infrastructure investment that is disruptive to functioning energy markets in New England (Figure 10).

[28] Energyzt, "Report: Winter Reliability Analysis of New England Energy Markets," Prepared on behalf of the New England Power Generator's Association, October 2014, http://nepga.org/14/10/energyzt-report-on-winter-reliability/

Figure 10: Illustration of supply curve with expansions and new pipelines



Source: Energyzt analysis.

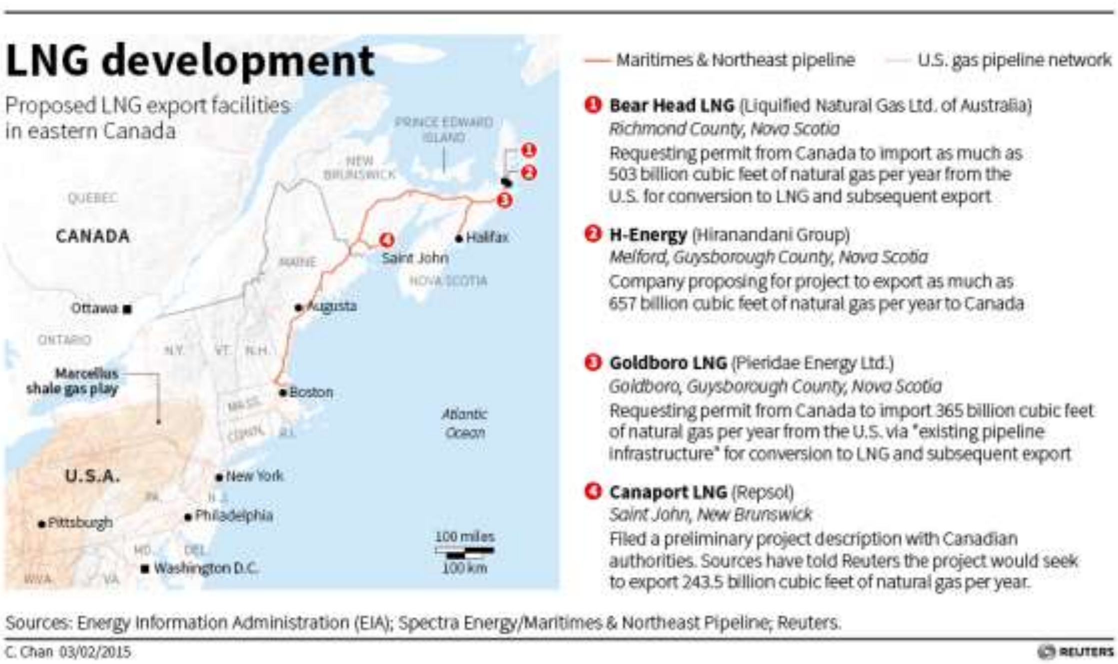
* Adds and Exp. includes incremental capacity of around 600 million cubic feet per day and variable cost of production for Atlantic Bridge Project, Spectra's Algonquin Incremental Market (AIM) Project, and CT Expansion Project; does not include capital investment.

** Northeast Energy Direct (NED) includes both the LDC contracted amount of 500 million cubic feet per day and currently uncontracted balance. NED and Access Northeast reflect marginal costs of delivered supply and do not include capital costs.

Incremental pipeline capacity funded by electricity ratepayers will require electric utilities to try to remarket the resulting excess pipeline capacity on the secondary market during at least nine months out of the year. Prices in the secondary market will be lower than what the utility committed ratepayers to pay in order to fund construction. This pipeline capacity will become a "stranded asset" – an asset that ratepayers do not need but are obligated to continue paying for through regulated rates.

The most likely secondary market will be Canadian Maritimes where production is dropping and several LNG export facilities have been proposed (Figure 11). In fact, Spectra Energy's Maritimes and Northeast pipeline with a capacity of 800 million cubic feet per day has announced plans to start flowing the other way.[29]

Figure 11: Map of proposed LNG export facilities in the Maritimes



Source: Sherwood, D., Thomas Reuters Foundation, "Analysis- Eastern Canadian LNG export plans face supply quandary," February 4, 2015, http://www.trust.org/item/20150204055734-bxg59

If enough natural gas flows through New England to the Maritimes for export from Canada, basis differentials could increase and New England electric ratepayers will have funded construction of pipeline capacity from which they receive no benefit.[30]

[29] See Marcellus Drilling News, "Canadian LNG Exports, New England Pipelines & the Marcellus," February 4, 2015,

http://marcellusdrilling.com/15/02/canadian-lng-exports-new-england-pipelines-the-marcellus/

[30] This would solve an existing problem of Marcellus gas producers who wish to sell into global markets via the Maritimes, but 1) would not be able to build a pipeline through New England due to siting issues if the pipeline was solely dedicated to LNG exports; and 2) could have trouble financing a pipeline without adequate contractual arrangements in place with a credit-

In summary, there is ample existing and planned energy delivery infrastructure in New England to ensure reliable, competitively priced natural gas supply during winter peak periods. The addition of proposed electricity ratepayer-funded pipeline(s) is an unnecessary capital cost and risk that may eventually harm New England ratepayers, not benefit them. Given anticipated market conditions, government-mandated funding of a new pipeline using electricity ratepayer dollars is likely to expose those ratepayers to a needless infrastructure investment to the benefit of gas suppliers, pipeline owners, Canadian Maritime LNG export facilities and foreign buyers of US LNG.[31]

3.2 LNG imports can be contracted to meet peak needs

In addition to sufficient natural gas pipeline capacity to provide reliable delivery during most winter peak conditions, New England has a substantial amount of LNG import capacity. New England benefits from four LNG import facilities, including Canaport in Canada; three are located off the coast of New England (Figure 12).

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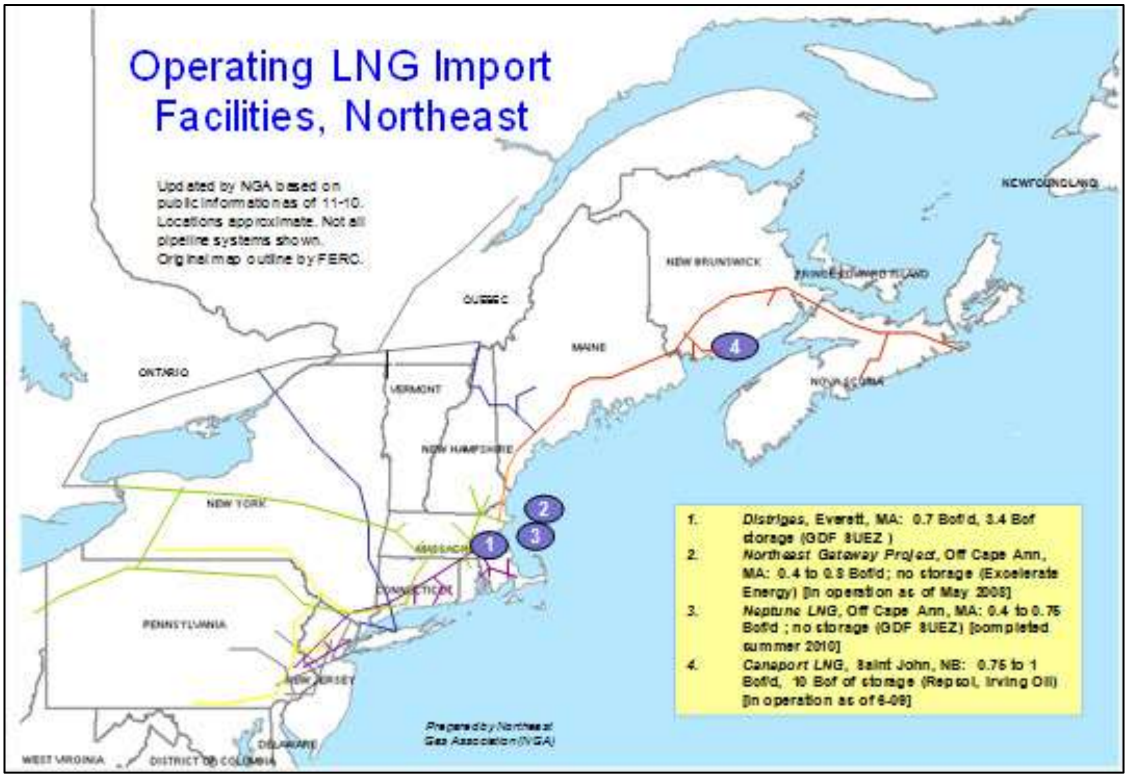
worthy entity to support financing. See Sherwood, D., Thomas Reuters Foundation, "Analysis-Eastern Canadian LNG export plans face supply quandary," February 4, 2015, http://www.trust.org/item/20150204055734-bxg59

[31] Ibid., The Marcellus gas industry appears to acknowledge the benefits that will accrue to its market participants,

> One of the biggest arguments anti-pipeliners have is 'the gas won't even stay here, it will be exported.' The argument goes that New England rate payers must help foot the bill for the new pipelines that will come to New England to deliver enough supply that there won't be shortages of gas during the three coldest winter months–December through February. **If New Englanders foot the bill and then the gas goes somewhere else–if big companies exporting it in Canada are the beneficiaries, is that not unfair?** We acknowledge such a case can be made. To which we say, figure out how to make it fair. Figure out how to lessen the burden on New England rate payers.

(emphasis added)

Figure 12: Map of existing LNG import facilities in New England



Source: Northeast Gas Association, http://www.northeastgas.org/about_lng.php

The primary LNG resource in the region is the Everett facility which can store 3.4 billion cubic feet of LNG and has the capacity to gasify (i.e., regas) and deliver a maximum 1 billion cubic feet per day into the Boston area on a discrete basis and 715 million cubic feet of gas on a continuous basis.[32] The facility has connections with two interstate pipeline systems as well as connection to an LDC system, serving nearly all of the gas utilities in New England. Everett also services key power producers, including a direct connection to a nearby 1,550 MW power

[32] The Northeast Natural Gas Association reports that Everett is capable of gasifying and delivering up to 1 Bcf per day on a non-continuous basis. "The Role of LNG in the Northeast Natural Gas (and Energy) Market" by Northeast Gas Association, February 2014, www.northeastgas.org/about_lng.php

plant.[33] This deliverability is incremental to the pipeline capacity since it is an injection of the commodity near the end of the pipe, a so-called back flow.

There are two other offshore facilities (Neptune and Northeast Gateway) at which tankers are able to unload LNG via specially designed regasification ships, then deliver the fuel into regional pipelines by a submarine connection. At full capacity, this infrastructure could deliver up to 1.35 billion cubic feet per day into New England. Given market economics, however, the two LNG buoy facilities of Neptune have been temporarily shut down, although Gateway flowed somewhat during the past winter. Nevertheless, the existing infrastructure remains available, under appropriate commercial terms, to meet near-term reliability requirements.

Finally, there are multiple small-scale peak shaving facilities under the control of LDCs which rely, in part, on truck deliveries of LNG from Everett. According to the Northeast Gas Association, New England LDCs control 16 billion cubic feet of storage at these facilities and have delivery capability of approximately 1.4 billion cubic feet per day.[34] The delivery capability from Everett to these peak shavers is estimated to be 100 million cubic feet per day via trucks.[35] In total, deliverability from the existing LNG facilities (on-shore and off-shore) is 3.7 billion cubic feet per day, nearly the maximum demand for natural gas in New England.

LNG import capacity has played a critical role in maintaining winter reliability as it provides a flexible, diversified and competitive supply option for natural gas. Existing LNG infrastructure represents enough delivery capacity to meet the entire winter peak demand (i.e., 3.7 billion cubic feet per day) on a continuous

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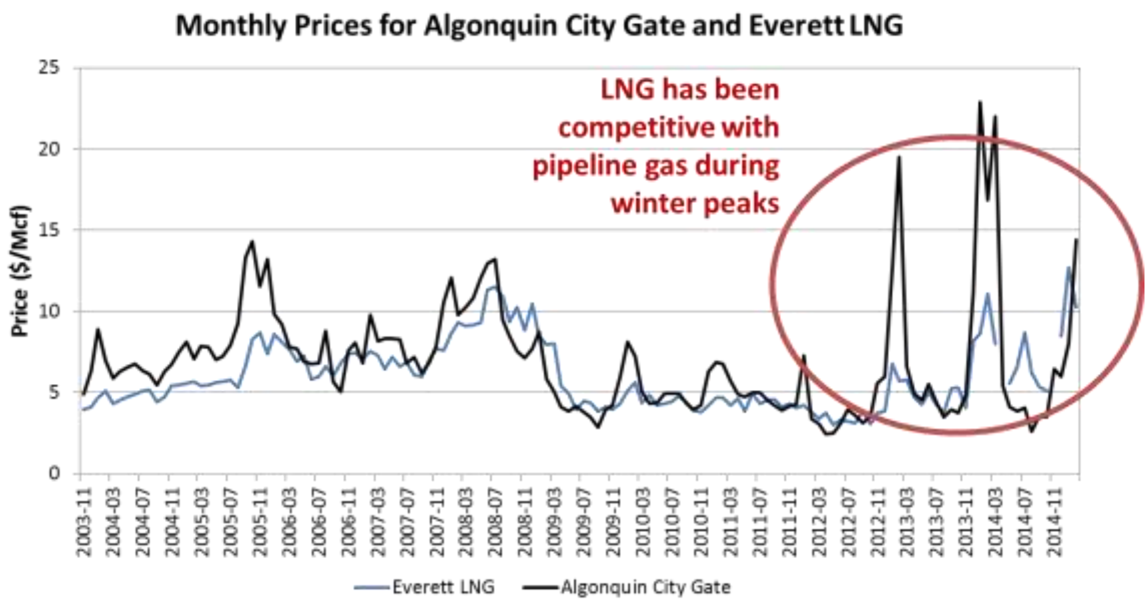
[33] GDF Suez, http://www.suezenergyna.com/lng-operations/

[34] Ibid.

[35] "DOMAC Facts & Figures" by Distrigas of Massachusetts (www.distrigas.com/ ourcompanies/lngna-domac.shtml accessed 8/14/14)

basis, as well as a higher peak delivery capacity with LNG storage that can hold more than five days equivalent of winter peak demand. LNG prices also have been competitive in the past, offering a hedge against natural gas price volatility from mainland resources (Figure 13).

Figure 13: Historic LNG prices at Everett vs. existing pipeline



Source: EIA, http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm

Going forward, LNG prices in New England may become even more competitive. LNG prices recently collapsed (from a range of $14 to $16 per mmBtu) and are now less than $10 per mmBtu. Some projections indicate that LNG will be around $5 to $6 per mmBtu over the next 5 years due to an anticipated increase in supply and Asian demand declines.[36] With lower global

[36] Timera Energy, "The next phase of global gas pricing," September 22, 2014,

http://www.timera-energy.com/the-next-phase-of-global-gas-pricing/

Reuters, "After half a decade apart, global prices converge," January 27, 2015,
http://www.reuters.com/article/15/01/27/lng-prices-global-idUSL6N0V603620150127

prices for oil and LNG, New England's LNG import options are an economic solution to a winter peaking problem.

A number of other studies have examined the economic benefits of LNG to New England, and we do not reproduce their results here except to note the impact of LNG on winter reliability and prices.[37] Based on our analysis, LNG has been critical to maintaining reliability and lower basis differentials during winter months. An important part of the New England winter peaking energy portfolio since the 1970s, LNG became a baseload resource, supplying natural gas into New England year round during the 2000s. More recently, LNG import facilities in New England have been underutilized, as illustrated in Figure 13 below.

Having less LNG in the system, the volatility of natural gas prices and level of price spikes in New England during the winter months of 2012/13 and 2013/14 increased. Although LNG continued to be delivered under contract to Mystic, Boston Gas system and via LDC trucks, albeit at declining levels over time, natural gas sendout into the Algonquin and Tennessee pipelines declined considerably during 2012 through 2014, before returning to historic levels during Winter 2014/15 (Figure 14). The reduction in LNG sendout into pipelines equated to around 2,000 to 3,000 MW of natural gas-fired production that, as explained further in the next section, had to switch to dual-fuel capability. Had LNG been more fully utilized, price volatility and basis differentials would have

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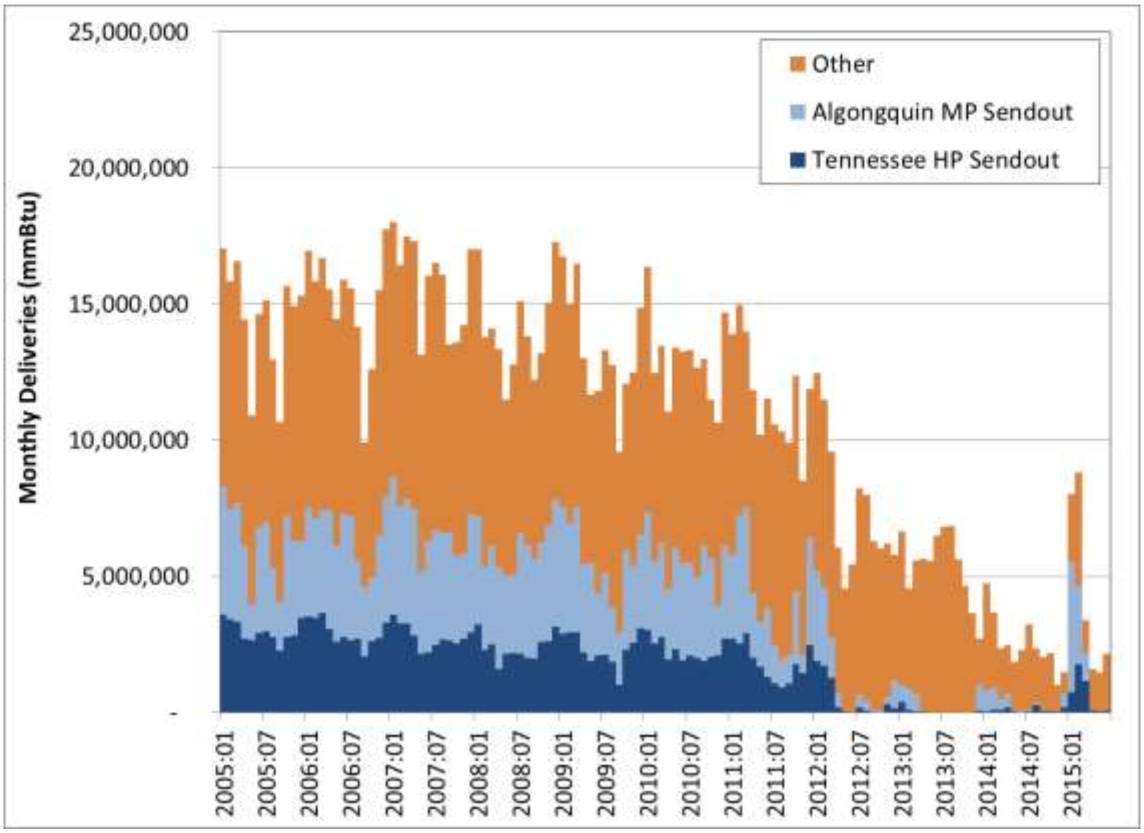
Tomlinson, C., "LNG Industry faces short-term glut but long-term opportunity," May 28, 2015, http://royaldutchshellplc.com/15/06/01/lng-industry-faces-short-term-glut-but-long-term-opportunity/

[37] Gellerman, B., "Old System, New Solution? Liquified Natural Gas could be Pipeline Alternative," March 11, 2015, http://www.wbur.org/2015/03/11/natural-gas-lng-everett-terminal

ICF International, "New England Natural Gas Supply and Demand: Post-Winter Review," Prepared for GDF Suez Gas North America, May 29, 2014, http://www.nescoe.com/uploads/GDF-SUEZ_CommenstonIGER_30May2014.pdf

Black & Veatch, project No. 178511, "Natural gas infrastructure and electric generation: proposed solutions for New England," prepared for The New England States Committee on Electricity, August 26, 2013, http://www.nescoe.com/uploads/Phase_III_Gas-Elec_Report_Sept._2013.pdf declined, as experienced during the winter of 2014/15 when LNG imports returned to roughly half of their 2008-20011 historic winter levels and sendout to pipelines approached historic levels.

Figure 14: Monthly LNG sendout in New England



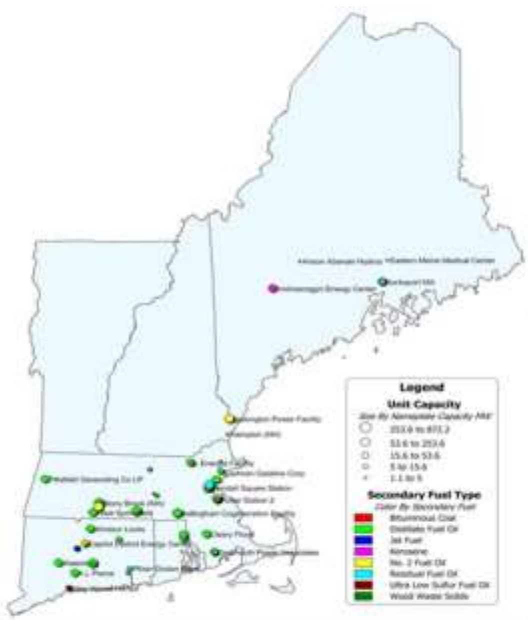
Source: Energyzt analysis of GDF Suez data underlying semi-annual reports to FERC

LNG import facilities are an existing energy asset that can provide winter reliability without expensive infrastructure investment costs and risks. Decreasing prices for LNG and substantial import capacity make LNG particularly valuable to New England, providing an immediately available, highly flexible competitive option to pipeline gas without any required capital investment or associate electricity ratepayer commitment. Although a recent announcement indicates that distribution companies in New England are entering into long-term contracts for LNG, this resource continues to be underutilized.[38] LNG should be considered as a potentially competitive resource in any economic analysis of alternatives to provide winter reliability.

3.3 Dual-fuel capability already exists

ISO-NE's winter reliability program recognized the existing assets of dual-fuel capability among generators in New England. During the past two winters, the winter reliability program helped to ensure that fuel oil was available to allow for these generators to run even if natural gas was not available or when gas was more expensive than oil.

Figure 15: Dual-fuel capability in New England



Total Generating Plants with Dual fuel Capability and Natural Gas as Primary Fuel

Location	# of Plants	MW Capacity
Connecticut	11	1,258
Maine	4	469
Massachusetts	26	4,192
New Hampshire	2	609
Rhode Island	3	594
New England	46	7,121

Secondary Fuel Type For NE States by Capacity (MW)

State	Distillate Fuel Oil	Other Fuel Oil	BIT Coal	Kerosene	Wood Waste
CT	990	268			
ME	187	31		164	88
MA	2,218	1,968	6		
NH	3	606			
RI	584	10			
TOTAL	**3,981**	**2,883**	**6**	**164**	**88**

Sources: EIA Form 816 via Ventyx, 2014 NERC Report on Polar Vortex

Sources: EIA Form 816 via Ventyx, 2014 NERC Report on Polar Vortex

As indicated in Figure 15, New England has around 46 plants representing nameplate capacity of nearly 7,000 MW of dual-fuel capability where natural gas

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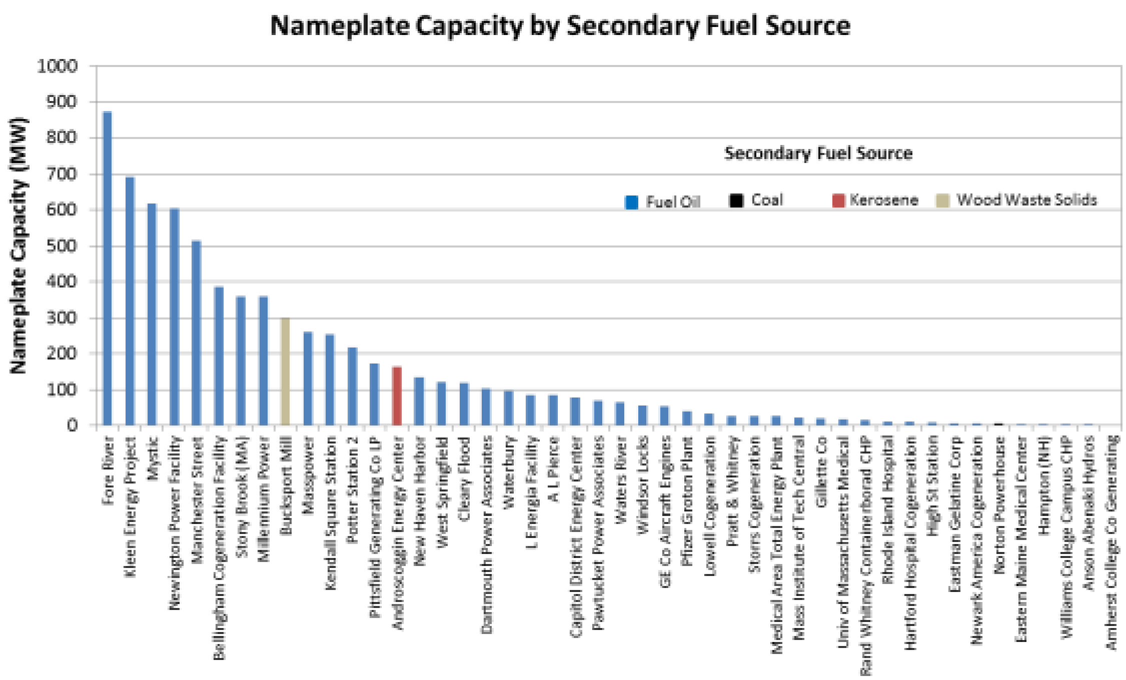
[38] Business Wire, "Distrigas to Fulfill Multiple LNG Contracts with Gas Utilities in New England; One Agreement Spans 10 Years of Supply," May 11, 2015,

http://www.businesswire.com/news/home/20150511005685/en/Distrigas-Fulfill-Multiple-LNG-Contracts-Gas-Utilities#.VaTLXn_bLmQ is the primary fuel; around 6,500 MW have fuel oil as a secondary fuel.[39] This represents a total net winter capacity of around 6,200 MW of natural gas capability that can switch to fuel-oil when required (see Appendix B). These units are located throughout New England, but are primarily clustered around the southern states of Connecticut, Massachusetts and Rhode Island. Some are quite sizable with Fore River offering close to 850 MW in nameplate capacity (Figure 16).

Figure 16: Nameplate capacity of natural gas-fired dual-fuel units



Sources: ISO NE SCC April 2015 Report. EIA Form 860 Report via Ventyx

Running these units on oil tends to be more expensive than natural gas under most conditions. During winter peak situations, however, dual-fuel capability can be critical to ensuring reliability and mitigating electricity prices. Dual-fuel capability effectively caps electricity prices at the lesser of natural gas or oil converted into electricity. At \$60 to \$70 per barrel for fuel oil, this provides an

[39] As indicated in Appendix B, we model 20 of these units representing 6,500 MW in the New England wholesale electricity market.

effective cap on natural gas prices in New England at around $12 to $15 per mmBtu and electricity prices of between $100 and $150 per MWh.

Furthermore, the incremental cost of installing dual-fuel capability is negligible, increasing capital costs by perhaps only 5 percent on new units (Figure 17).[40] Most of the recent applications to build new natural gas-fired units (both combined cycles and combustion turbines) include dual-fuel capability. Including this capability provides optionality to the owner as well as confirmation to siting commissions that the generating capability will be available when needed during extreme winter conditions. It also could prove to be very valuable during winter conditions in meeting ISO-NE's performance incentives for reliability.

Figure 17: Cost of dual-fuel capability in new units

Dual fuel capability increases capital costs by less than 5%

Installed Cost Comparison (2018$)

	Combined Cycle		Simple Cycle	
	Gas-only	Dual fuel	Gas-only	Dual fuel
PJM	1,194 $/kW (578 MW 2x1 7FA CC)	1,232 $/kW (578 MW 2x1 7FA CC)	945 $/kW (385 2 x 7FA SC)	1,014 $/kW (385 MW 2 7FA SC)
NYISO			1,680 $/kW (180 MW 2 x LMS100)	1,743 $/kW (180 MW 2 x LMS100)

Source: Cost of New Entry for Combustion Turbine and Combined Cycle Plants in PJM", by the Brattle Group and Sargent & Lundy, May 15, 2014; "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator", by NERA and Sargent & Lundy, August 2, 2013.

[40] "Cost of New Entry for Combustion Turbine and Combined Cycle Plants in PJM", by the Brattle Group and Sargent & Lundy, May 15, 2014; "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator", by NERA and Sargent & Lundy, August 2, 2013.

In addition, it is possible to convert existing natural gas units to dual-fuel capability to increase the flexibility and diversification of New England's power mix. The possibility of and costs of conversion are extremely site specific and would need to be assessed on a case-by-case basis. Market-based Pay-for-Performance will allow natural gas-fired generators without existing dual-fuel capability to assess the relative costs of converting versus procuring LNG, firm delivery capacity, or other fuel-security measures in winter months.

Currently, there is more than enough existing dual-fuel capability in New England to provide energy options in the event of natural gas delivery shortfalls. These units also serve to mitigate prices for natural gas and electricity.

3.4 Canadian import alternatives bear consideration

There are two proposals to develop HVDC transmission lines to bring hydroelectric imports into New England from Canada totaling 2,400 MW of new non-gas-fired generation capacity. If even half of that amount of hydroelectric power comes into New England, it would be more than double the capacity of recently announced retirements of non-gas-fired generating capacity and anticipated new builds, negating the need for an incremental natural gas pipeline to support natural gas-fired generation on a baseload basis. However, as our analysis shows in section 4.2.3, a new transmission line from the north may displace gas throughout the year, but does not necessarily provide a flexible or effective solution to winter reliability issues.

Although transmission of hydroelectric power from Canada is not being proposed as a winter peaking solution, but as a means of meeting environmental renewable energy targets and emissions limits, it could have an impact on total gas demand in the region. The potential gas demand impact of a new transmission line importing hydroelectric power into New England is analyzed in the next section.

4 ANALYSIS AND RESULTS

To provide further insight into potential impacts of dual-fuel capability and a new transmission line into New England from Canada, this section describes the results of our economic analysis of the cost of the alternatives described above. In examining these alternatives, we focus on winter reliability, assess market conditions with and without these alternatives and perform a sensitivity analysis on normal versus extreme market conditions. In addition, we run a market model to understand the potential impact on natural gas consumption by the electricity sector and associated energy prices.

4.1 Cost analysis

As already mentioned, price signals indicate a peaking problem. In general, peaking problems require peaking solutions. Building a new natural gas pipeline is a baseload solution that can have adverse consequences on the market, exacerbating already negative basis differentials during the nine months of the year when winter peaking capability is not required. That said, a baseload solution can be a more cost effective approach if overall average costs are lower than a peaking solution for a given number of peaking events.

To examine the relative cost of a new pipeline compared to LNG and dual-fuel capability, it is important to understand how often a problem occurs. Figure 18 shows the price duration curve for natural gas basis differentials at Algonquin Citygate compared to TETCO 3. Although basis differentials traditionally have been calculated against Henry Hub, they are calculated against PJM's natural gas prices to determine whether there is a pipeline constraint between the two natural gas trading hubs, one of which is physically closer to Marcellus Shale, that can be remedied with additional pipeline capacity.

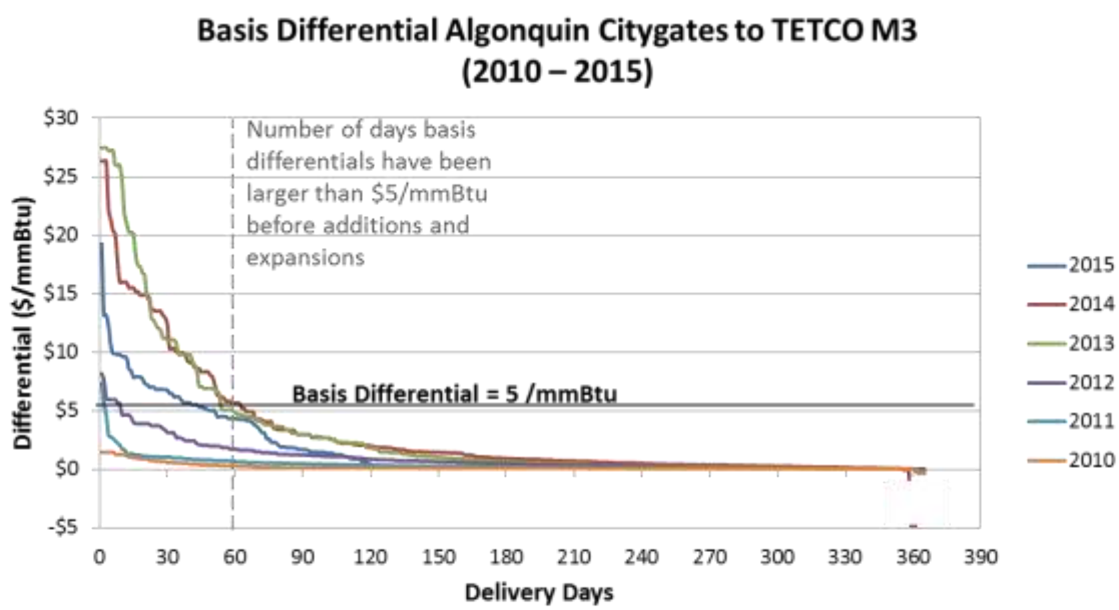
During the 2010 to 2012 calendar year, natural gas prices rarely deviated by more than $5 per mmBtu between the two delivery hubs. In 2013 and 2014, basis differentials above $5 per mmBtu occurred during 60 delivery days. As existing energy infrastructure resumed delivery (e.g., dual-fuel units and LNG sendout into pipelines), basis differentials fell during Winter 2014/ 2015 and exceeded $5 per mmBtu during fewer than 45 delivery days.

ENERGYZT

Historic levels of delivery from existing energy infrastructure would reduce basis differentials above $5 per mmBtu to fewer than 10 days per year, as occurred in the 2010 to 2012 period. With the incremental 600 million cubic feet per day of gas pipeline expansions already underway, expected basis differentials above $5 would occur even less frequently.

To be conservative, however, the analysis of the cost of alternative proposals below assumes that a solution is needed for 60 days of natural gas delivery as was required during the extreme winter events of 2012/13 and 2013/14 when existing energy infrastructure was underutilized, record cold snaps happened, and a number of transient equipment malfunctions occurred.

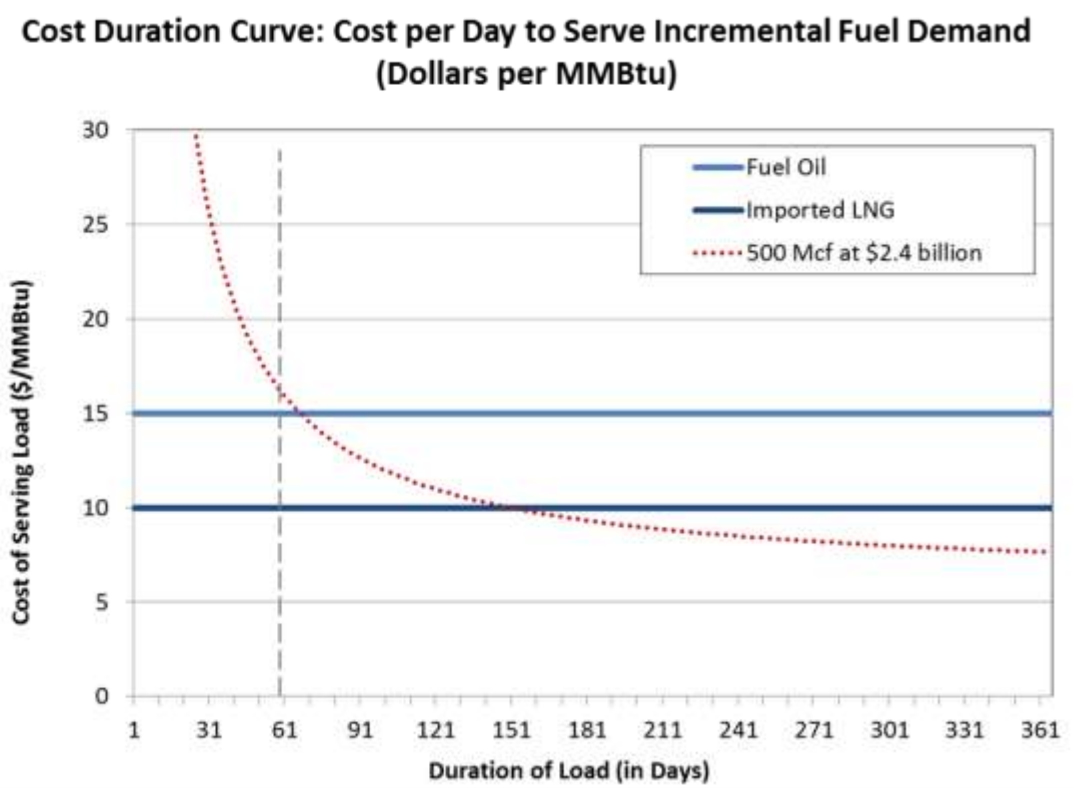
Figure 18: Duration curve of basis differentials by year



Sources: Interconnect Exchange data via Ventyx

The next step is to compare the relative costs of alternative solutions. Figure 19 compares the total costs of a new pipeline divided by number of events in which it would be needed to the variable costs of LNG and dual-fuel capability. At current market prices, LNG is the most cost-effective solution to winter peak issues that cause basis differentials to deviate by more than $5 per mmBtu, and is the economic solution under current commodity prices even if basis differentials diverged by more than $2 per mmBtu every day for five months out of the year. With fewer than 60 days of deviations above $5 per mmBtu, however, even the cost of fuel oil incurred by dual-fuel units is a more cost-effective peaking solution than building a new pipeline for purposes of winter reliability.

Figure 19: Comparative cost analysis[41]



Sources: Energyzt analysis of average cost of incremental supply (variable and capital costs) and does not include price suppression due to excess natural gas supply into the market. Assumptions reflect current market conditions during winter peak periods

[41] Key assumptions: Pipeline cost = $2.4 billion
Cost Recovery Factor = 12.5%
Variable Costs = $5 / mmBtu gas supplies and $1 / mmBtu other
Cost of Fuel Oil = $15 / mmBtu
Cost of LNG = $10 / mmBtu

Proponents of a new pipeline have argued that increasing natural gas delivery capability into New England will reduce natural gas prices and create benefits for electricity consumers in the form of lower electricity prices. These analyses are problematic for the following reasons:

1) **Winter Price Spikes:** Historic prices realized only during winter periods when existing energy infrastructure was not being utilized should not be the reference case used to calculate benefits as market conditions reflect a transient event caused by failure to contract existing energy infrastructure which already is being addressed.

2) **LNG Availability:** Some of these studies assume LNG will not be available going forward or will be too expensive. In fact, there currently is an oversupply of LNG due to shale production and decreasing demand from Asia, lowering LNG prices to very competitive levels. As already mentioned, contracts already are being entered into by New England natural gas distribution companies to lock in lower priced LNG under current market conditions. Such contracts for LNG delivery from the east may free-up firm pipeline capacity coming in from the west.

3) **Pipeline Expansions Underway:** An additional 600 million cubic feet per day of pipeline capacity, funded by traditional funding mechanisms and not electricity ratepayers, already is underway and projected to come online by 2018. This capacity needs to be included in any assessment of the impact on winter reliability.

4) **Equivalent Benefits of Existing Infrastructure:** As seen during Winter 2014/15, appropriate contracting with existing infrastructure decreased basis differentials by half compared to the prior winter. Any benefit in lower gas (and therefore electricity) prices that can be achieved by a new gas pipeline also can be achieved by utilizing existing energy infrastructure such as dual-fuel capability and LNG. Therefore, benefits are close to equivalent for a given mmBtu of natural gas addition or

displacement when new pipeline capacity is required to meet winter reliability needs, making the analysis one of comparative costs.[42]

As shown by the experience last winter and described in more detail in section 3.1, when existing energy infrastructure is utilized as was done historically, basis differentials return to historic levels.

4.2 Market analysis

To project demand for natural gas from the electricity sector and to assess the impact of dual-fuel capability and a transmission line from Canada, we use an updated GE Maps model of New England using the most recent ISO-NE CELT reports and EIA Annual Energy Outlook projections. Our base case and scenarios are provided in Appendix B. This section summarizes our results.

4.2.1 Base Case: Shows declining demand for natural gas

The initial base case sets a market projection under assumptions supported by the most recent 2015 CELT report. The 2015 CELT report implements information on announced retirements and capacity additions as well as load forecasts.

In addition, the base case assumes the ISO-NE projections that implement a number of policy initiatives that serve to diversify the fuel base and lower emissions including RPS requirements, RGGI emissions targets, distributed generation, net metering, and energy efficiency.

The net result of these programs is a limited need for new natural gas-fired generation capacity going forward. Under 2015 CELT assumptions, assuming construction of new generation that has cleared the forward capacity market and renewable build-out to reflect policy initiatives, we project that new natural gas-

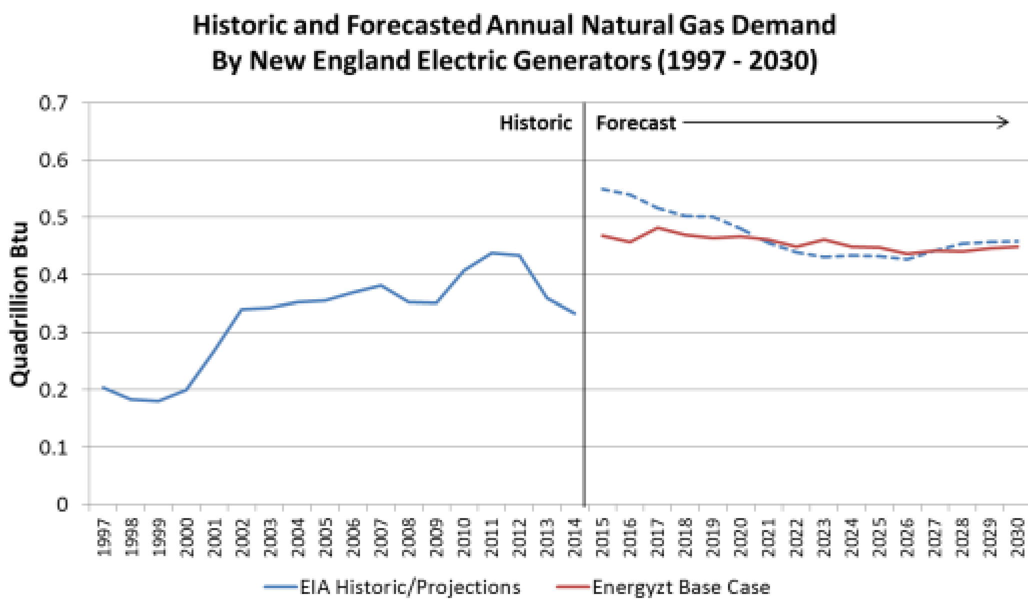
[42] Although the variable cost of each option may differ, they would be displacing the most expensive resource in the supply stack, effectuating a decrease in basis differentials and absolute prices, unless the proposal is to flood the market, in which case prices would artificially revert to the marginal cost of the resource that would now be on the margin.

fired generation will not be required to meet reserve margins through the next decade.[43]

These policies also create a gradual decline in natural gas consumption by the electricity sector over time. After an initial uptick resulting from the retirement of Brayton Point (a coal plant) and new gas-fired generation projects coming online, projected natural gas consumption declines as more efficient units displace less efficient units. This decline is negligible, however, representing a reduction of only 20 million mmBtu or less than 0.05% per year from 2017 to 2027. Regardless, natural gas consumption is not anticipated to increase dramatically over the coming decade, questioning the need for a new gas pipeline paid for by electricity ratepayers. These projections are consistent with historic levels as well as long-term forecasts produced by the EIA (Figure 20).

[43] This is very different than the market situation one year ago when the 2014 CELT Report indicated a projected shortfall as soon as 2018 due to announced retirements and limited entry of new generation capacity. FCM prices settled at higher levels and cleared new capacity that would meet ISO-NE's required reserve margins, now reflected in the 2015 CELT Report.

Figure 20: Base Case -- Natural gas consumption by electric generation



Source: Energyzt analysis; Annual Energy Outlook 2015.

4.2.2 Dual-fuel capability provides a flexible, peaking solution

Dual-fuel capability is used only during extreme winter conditions when either lower cost resources are not available or fuel oil is more economic than natural-gas fired units. Prior to Winter 2012/13, the need for dual-fuel generation was minimal as LNG imports provided a cost effective resource of incremental gas supply. When LNG contracts rolled off in 2012, this low-cost resource was no longer available at the same levels and dual-fuel became critical during the peak winter months, corresponding to ISO-NE's winter reliability program.

As a result, dual-fuel units would not be expected to operate on a regular basis during average weather conditions or when LNG is contracted at adequate levels. Our analysis supports this conclusion and does not run dual-fuel units using fuel oil under average conditions.

Using fuel oil and residual oil prices from our fuel projections and heat rates obtained from the EIA (Annual Generation Electricity Report,) the price of gas would need to be in the low $20's per mmBtu to power plants – significantly above our typical projected gas prices for New England that are in the $3.60 to $4.60 per mmBtu with short-term peaks in the winter up to around $10 per mmBtu. Once natural gas prices do exceed that level, however, dual-fuel units become economic and can be used to mitigate electricity prices and ensure winter reliability. They are insurance against extreme weather conditions and emergency events.

To test the responsiveness of dual-fuel units to gas and oil prices, we ran GE MAPs using alternative natural gas prices indexed to oil for the winter months of December, January, February and March in the years 2015, 2020 and 2025.

From these sensitivity runs we can conclude that switching from gas to oil is a direct function of the price differential between gas and oil. Even a small differential of gas prices exceeding oil prices results in switching 3,464 MW from gas to oil in market conditions such as those during the winter months of 2015.[44]

As the price differential between natural gas and oil gets larger, more gas is displaced. For example, a price difference of $5.00 per mmBtu in 2020 switches nearly the entire fleet of dual-fuel units. As more efficient units come online, less natural gas is required per megawatt-hour of production, and the need for dual-fuel capability declines over time for a given price differential (Figure 21).

[44] This responsiveness is a result of the model which assumes efficient dispatch to optimize production, and may not be representative of real-world conditions such as those which were experienced during Winter 2012/13 when dual-fuel capability was not prepared to deliver. However, it does illustrate the potential flexibility that can be achieved with proper planning and optimized bidding behaviour reflecting relative costs of alternative fuel sources.

Figure 21: Dual-fuel generation switch from gas to oil (MW)

Year (Winter - 2nd Week January)			
Natural gas price adder to oil	**2015**	**2020**	**2025**
$ (0.50)	0	0	0
$ (0.10)	0	0	0
$ 0.00	560	0	0
$ 0.20	3,464	4,575	4,054
$ 0.50	3,313	4,575	4,054
$ 1.00	3,464	4,575	4,243
$ 5.00	4,770	5,827	4,736
$ 10.00	4,770	5,827	5,354

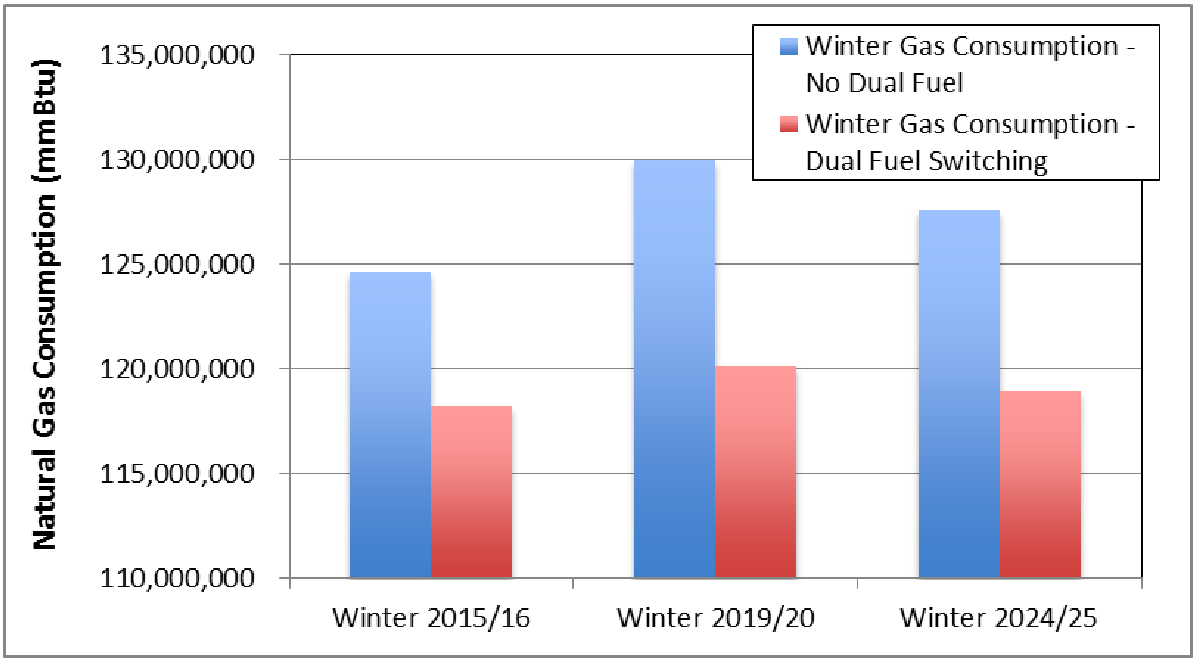
Source: Energyzt analysis, GE MAPs model runs under extreme market conditions and variable ratios of natural gas versus distillate prices

We also examined projected gas consumption under extreme winter conditions with no LNG, as occurred during Winter 2012/13 and Winter 2013/14, but with dual-fuel capability. To control for other factors, we kept electric load constant even though electricity demand could increase during extreme winter events.[45]

As shown in Figure 22, conversion to dual-fuel capability during cold weather conditions can decrease demand from natural gas-fired generation dual-fuel units, reducing natural gas consumption by 10 million mmBtu for the season. In 2020, the month of January experiences a 7.4 million mmBtu reduction in natural gas consumption, illustrating the importance of intermonth flexibility to address winter weather which can vary from week to week.

[45] Given demand response and participation of load reductions in New England's, increases in electricity demand could be mitigated by higher prices during extreme weather conditions.

Figure 22: Reduction in natural gas consumption due to dual-fuel units



Source: Energyzt analysis, GE MAPs model runs

This switch between high gas prices and lower priced oil also creates benefits in the form of lower electricity prices of around $100 million for the 2019/20 winter season, with the majority of those benefits occurring in January when the differential between natural gas and oil prices are the highest. Therefore, dual-fuel capability can provide benefits equivalent to a new pipeline during extreme weather and market conditions when diversity is most needed without adversely impacting the market during other periods.

We caution against using any analysis based on the prior winters to estimate benefits, however, as those extreme conditions should not occur if the existing energy assets are commercially contracted for deployment and market response continues to occur.

4.2.3 A new Canadian transmission line proposed as a baseload solution

New England electric distribution companies in Massachusetts, Rhode Island, and Connecticut have developed a Clean Energy RFP to solicit bids for renewable resources which include building new HVDC transmission lines from Canada for hydroelectric imports. There are two known proposals to develop an HVDC transmission line to bring hydroelectric imports into New England from Canada totaling 2,400 MW of new non-gas-fired generation capacity. As a sensitivity case, we assumed half of that amount of transmission capacity is built and fully utilized for imports into New England during peak hours throughout the year.

The effect of adding a 1,200 MW transmission line from Canada to the Base Case for peak hour delivery is summarized in Figure 23. Such a project would decrease natural gas consumption by around 40 million mmBtu per year, with around 2.5 to 3 million mmBtu per month reduction during winter months.

Interestingly, the transmission line may displace less natural gas during winter months than dual-fuel units. First, 1,200 MW of inframarginal supply coming in from Canada is less than 6,200 MW of dual-fuel switching capability that is available to meet winter reliability needs if properly contracted.[46] Second, displaced units are more likely to include oil-fired or other non-gas fired generation peaking units during winter peak conditions. Lastly, long-distance delivery from a winter-peaking electric system may introduce a new set of delivery risks.[47] The analysis shows that the Canadian transmission line, as a

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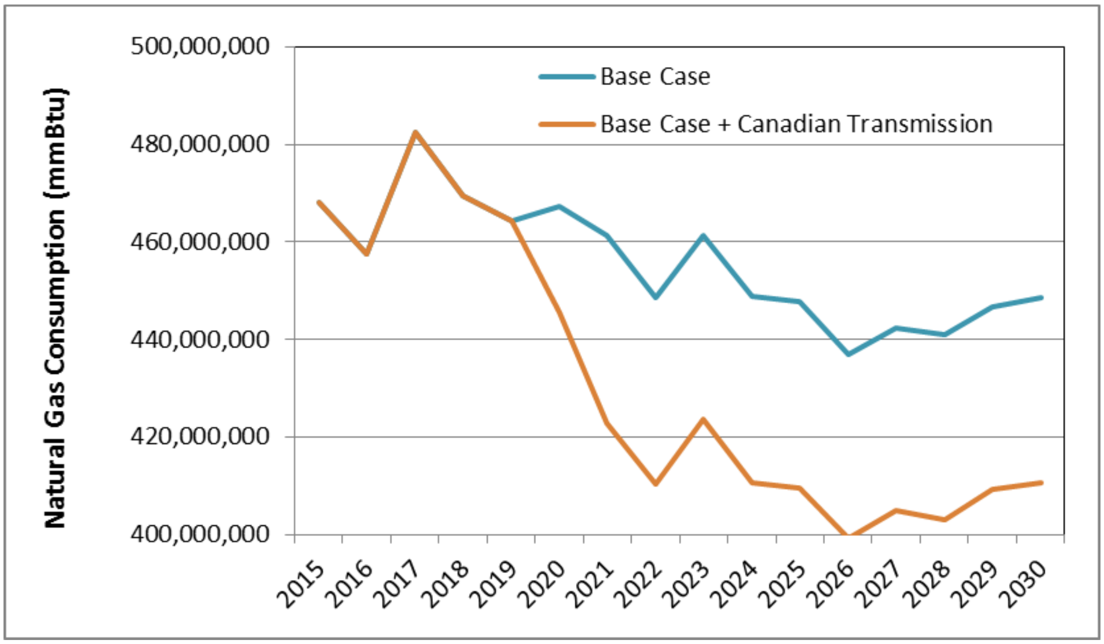
[46] The analysis does not assume use of the pipeline during off-peak hours and does not assume any curtailment of interruptible energy from Canada.

[47] Emergency conditions occurred in New England during the two extreme winters on December 13, 2013 and December 4, 2014 when significant curtailment of Canadian imports occurred. In 2013, curtailment occurred due to loads running over forecast and imports to the U.S. required in-Province to meet reserve margins. In 2014, over 2,000 MW of imports from Canada were cut due to a fault on high voltage transmission lines, later found to be the result of sabotage.

baseload resource offers less flexibility than dual-fuel capability which can be deployed only when needed during extreme weather conditions.

Figure 23: Impact on annual natural gas consumption from Canadian imports



Source: Energyzt analysis, GE MAPs model runs

5 IMPACT OF GOVERNMENT INTERVENTION

Although government intervention can be warranted when a market failure occurs, intervention in a working marketplace can be destructive. In this case, there appears to be a misinterpretation of price signals from the past three winters that could result in an unsupported policy direction.

High natural gas prices and basis differentials that occurred during the winters of 2012/13 and 2013/14 do not reflect a need for new pipeline capacity. A simple examination of load factors indicate that there is more than enough existing pipeline capacity and other winter reliability resources to meet demand for natural gas during winter months. Furthermore, investors are moving forward with expanding existing pipelines to provide more than 600 million cubic feet per day of delivery capacity.

Instead, price spikes during those winters reflect the rolling off of certain LNG contracts that previously had mitigated winter price spikes by providing up to 650 million cubic feet per day of sendout capability and an average daily sendout of 200 million cubic feet per day. When LNG contracts were not renewed, New England did not enjoy the price mitigation, diversification, pipeline compression from the east to counter inflows from the west, and reliability LNG historically offered the region. Combined with transient events such as compressor equipment failure and withdrawn imports from other jurisdictions due to their own winter emergencies, plus limited dual-fuel capability the first winter, prices spiked.

Once dual-fuel capability was assured through the ISO-NE winter reliability program and LNG imports resumed, albeit at half of historic levels this past winter, basis differentials were reduced by nearly half despite the same extreme winter conditions if not worse. This reduction in basis differentials is equivalent to public estimates of the benefit of a new pipeline, but without the upfront infrastructure investment.

Going forward, dual-fuel capability and LNG provides economic solutions with the benefits of diversification. Responding to market prices, gas distribution companies have entered into long-term contracts for LNG. ISO-NE is developing a market-based approach to ensuring capacity availability and performance when needed as part of its performance incentive program that is agnostic to fuel type to be implemented in 2018. Dual-fuel capability continues to be available and is being added as a standard offering on new natural-gas fired generating units. New pipeline capacity through expansions are underway to implement more than 600 million cubic feet per day of delivery capacity. The extreme price signals New England experienced during Winter 2012/13 and 2013/14 should not repeat themselves again unless these investments do not proceed and/or the region fails to commercially contract to use the existing energy infrastructure already in place.

If the government were to move forward with proposals to fund a new pipeline with regulated electricity ratepayer funding, an uneconomic solution will occur. A new natural gas pipeline is not required now or for at least the next decade under current policies that promote renewables, energy efficiency and demand response given existing and planned energy infrastructure. If a transmission line from Canada is built as part of the clean energy program to reduce carbon emissions and increase renewables, there will be even less need for a new natural gas pipeline. Proceeding with the proposal to build another 500 to 1,000 million cubic feet per day of additional pipeline capacity funded by electricity ratepayers will simply flood the market.

With negative price differentials (which we already are seeing during non-winter months) and lack of demand, gas imports from Marcellus will find its natural market, most likely in the Maritimes for export as LNG. Spectra already has announced that it expects natural gas flows from the Maritimes into New England to be reversed. Natural gas trade journals acknowledge that a new pipeline could be used at least nine months of the year to flow natural gas into Canada. In effect, electricity ratepayers will have subsidized a natural gas pipeline for the benefit of Marcellus Shale producers, gas marketers, and Canadian LNG export facilities.

Government intervention in working markets creates long-term problems. Energy markets are dynamic, constantly changing and adjusting to market forces. The energy markets in New England are working, and price signals from the past few winters are signaling a need to contract for existing energy infrastructure, not to build new pipelines. The market is responding by doing so. Moving forward with a new pipeline funded by electricity ratepayers risks stranded investment and ratepayer burden for the benefit of a number of other market participants. Such an intervention will confound and inhibit future competitive market investment, possibly leading to future capacity shortages and/or a trend of increasing reliance on government support by private investors for new infrastructure as is being required by proponents of the plan to rely on electricity ratepayers.

Furthermore, funding a new pipeline through the electricity sector is inconsistent with other policies that already are being funded for by electricity ratepayers and result in a projected decline for natural gas in New England wholesale electricity markets.

Given anticipated market conditions, the most recent projections by ISO-NE, and environmental policies in place at the state and federal levels, a government-mandated funding of a new pipeline using electricity ratepayer dollars (which has never been done before) is likely to expose those ratepayers to a needless infrastructure investment to the benefit of others.

6 CONCLUSIONS

Although the extreme winters of 2012/13 and 2013/14 created peak prices with higher than average basis differentials, these price signals do not indicate a shortfall in baseload delivery capacity. In reality, there is a significant amount of underutilized natural gas pipeline capacity with more being built, as well as significant amount of existing infrastructure that offers an economic source of diversification and reliability.

Winter peak price signals reflect a divergence in basis differentials above $5 per mmBtu less than 60 days out of the year. This is reflective of a peaking problem that is best solved with a peak solution, not a baseload infrastructure investment. Fortunately, there is a significant amount of existing energy infrastructure already in place and being expanded to meet winter reliability requirements, including existing pipeline capacity, dual-fuel capability, LNG import infrastructure and planned pipeline expansions that do not rely on electric ratepayers subsidizing a new natural gas pipeline. A moderate level of contractual arrangements were in place for Winter 2014/15 and price spikes experienced the previous winter were reduced by half. Additional underutilized capacity remains available and using it more fully could have an even greater positive impact for the region.

To test our hypothesis that dual-fuel capability is sufficient to address winter peaks, with and without LNG imports, we ran our market model through 2030. The results confirm our expectation that dual-fuel capability is not needed under average conditions but serves as an insurance policy for extreme winter conditions when other energy infrastructure is not available. Dual-fuel capability can generate benefits in the form of lower electricity prices to electricity consumers of around $100 million during the 2019/20 winter season with contracting conditions similar to Winter 2012/13 and Winter 2013/14, and reduce natural gas consumption by up to 7.4 million mmBtu per month when needed most under projected conditions. A new transmission line from Canada reduces gas consumption year round, but by less than the full 1,200 MW of capability, or around 2.5 million mmBtu per month, due to oil-fired generation displacement. Dual-fuel capability is a more flexible peaking resource.

There are a number of policy initiatives in place that lower new natural gas demand and preclude the need for a new pipeline. Federal and state programs to support renewable resources which minimize future projections of natural gas demand as well as low load growth expected due to demand response and energy efficiency programs limit the potential growth of natural gas demand in New England. Under the base case, natural gas consumption in New England is expected to increase in 2017 due to the retirement of Brayton Point, followed by a steady decline as more efficient natural gas units come online. Consistent with the EIA's long-term projections, natural gas demand in New England is not projected to increase under current projections of market conditions and environmental policy, but to decline.

In the near-term, more than 600 million cubic feet per day of pipeline expansion, new LNG contracts entered into by gas distribution companies, and ISO-New England's programs to ensure performance in the forward capacity market are market-based solutions that will mitigate winter reliability concerns and high energy prices. The potential for lower cost, non-gas-fired generation imports via a transmission line from Canada, if built as part of the clean energy program, also will diversify the generation base in New England.

As a result, energy infrastructure is adequate over the next ten years to support winter reliability. Significant conversion to natural gas-fired generation is required to justify new pipeline capacity, which is expected to be limited by other policies that support renewables, imports and limited load growth. Even during extreme winter conditions, new pipeline capacity is not required to meet New England natural gas demand needs given existing infrastructure, current market conditions, and policy initiatives. In the meantime, market-based solutions are occurring in the context of policy initiatives that propose to diversify our power production resources and resolve concerns about an overreliance on natural gas.

New England has competitive markets for both natural gas and electricity. These markets have shown a keen ability to respond to market price signals and winter reliability programs, as seen during the 2014/15 winter. The combination of LNG imports and dual-fuel units reduced basis differentials by close to 50 percent, roughly the same benefits as public estimates of a new pipeline, without any upfront capital cost. This benefit can be expected to continue, without the capital investment associated with building a new natural gas pipeline funded by electricity ratepayers, so long as commercial contracts are in place to utilize existing infrastructure.

If there is a market failure contributing to high winter prices, it is due to a lack of incentive to enter into contracts to utilize existing capacity. High prices have created an incentive. ISO-NE market-based performance incentive programs motivate contracting with existing infrastructure. Competitive energy markets in New England respond to incentives, as seen by the experience from Winter 2014/15. They can be expected to respond as conditions change going forward.

Contracts, not construction, are required. New England's energy markets are working.

APPENDIX A: About Energyzt

GLOBAL TEAM OF ENERGY EXPERTS

Energyzt is a global collaboration of energy experts who create value for our clients through actionable insights. Combining deep industry expertise with state of the art analytical capabilities, we help companies make informed business decisions that create competitive advantage. With changing dynamics of the energy industries increasing market uncertainty and business risk, a more rigorous approach is required.

MULTIDISCIPLINED EXPERTISE

Energyzt is structured into three functional areas of excellence that include advisory services, industry analytics, and support for business development functions. Energyzt consists of a core team of energy experts representing the power sector, transmission, natural gas industry, coal markets, environmental policy and finance, along with an overseas team that offers operational research, software programming and modeling support.

APPLIED EXPERIENCE

Members of the Energyzt team have long-standing history working in industry, economic consulting firms, management consulting firms, private equity, research companies, engineering companies and government. The combination of industry expertise, market experience, and advanced analytics brings a unique set of market insights that are supported by facts and defensible in a court of law or regulatory hearing.

APPENDIX B:
GE MAPS Data Sources and Input Assumptions

B.1: OVERVIEW OF GE MAPS MARKET MODEL

In this study, Energyzt used the GE Multi-Area Production Simulation ("MAPS") market model to forecast future electricity prices, generation, production costs and fuel consumption within ISO-NE, the New England electricity market.

MAPS is a detailed optimization model that simulates the hourly operation of individual generating units and power flows across the transmission system within a electricity pool or pools[1]. MAPS is widely used in the electricity industry and was developed originally 40 years ago by GE.

For purposes of this analysis, ISO-NE was represented as a single pool and simulations were run for 2015 to 2030. Imports/exports from/to other pools in the Eastern Interconnect were modeled as hourly flows, based on historical data from 2011 – 2013. This simplification of the Eastern Interconnect was appropriate for this analysis because of the focus on ISO-NE and the relatively simple transmission interconnections between ISO-NE and surrounding regions.

From the detailed hourly simulations, power prices,[2] emissions, generation, duel consumption and operating costs were estimated across the ISO-NE system.

The purpose of the MAPS simulations was to quantify, for the ISO-NE electricity market, the potential benefits of alternative solutions to winter reliability. In addition to

[1]MAPS performs a security constrained least-cost dispatch of the generation system, and takes into account the effect of possible transmission outages in the optimization process. Consequently the generation solution is robust.

[2] MAPS estimates electricity prices based on locational marginal pricing, which is the price-setting methodology deployed by ISO-NE and other U.S. electricity markets

realistic forecasts of natural gas demand for purposes of understanding the need for a new natural gas pipeline, we calculated the benefits of dual-fuel-capability units and of additional transmission capacity to bring hydroelectric power from Canada during peak hours.

MAPS was run to simulate the following:

1. Base Case that reflects the 2015 ISO-NE CELT Report with dual-fuel capability
2. Base Case with no dual-fuel capability
3. Base Case with additional electricity imports from Canada starting in 2020 via a new 1,200 MW transmission line during peak hours
4. Scenario 1 with extreme gas prices in winter months
5. Scenario 3 with extreme gas prices in winter months

In MAPS, with extreme winter prices representing a cold winter with low LNG imports, such as what occurred in the 2012/13 and 2013/14 winters, a dual-fuel-capable units switch to FO2 when this is less expensive than gas.

Assumptions underlying these model runs are described more fully below.

B.2. GE MAPS DATA ASSUMPTIONS

Key assumptions in MAPS include the following:

- **Demand:** Peak and energy demand forecasts are input into the model on an annual basis and converted into hourly demands using historical demand patterns

- **Supply:** Existing generation is modeled at the unit level, based on historical operating characteristics, including capacity, variable operation and maintenance ("O&M") costs, heat rates, emissions rates and other operating parameters such as minimum up and down times.

- **Capacity Build-out:** New generation is based on announced projects that are under construction or, in some cases, permitted. The characteristics of new generation are based on existing units, or expected technologies, as appropriate.

- **Fuel Costs:** Forecasted fuel prices for coal, gas and oil are represented on a weekly, monthly or annual basis as necessary and are incorporated into the calculation of the marginal cost of production for each generating unit.

- **Emissions Costs:** The cost of emissions is incorporated into the marginal cost of production. Forecasted prices for CO_2, SO_2 and NOx allowances are combined with assumed emissions rates for each unit, to give an emissions cost per MWh for each unit.

- **Transmission:** GE MAPS contains a representation of the ISO-NE transmission system in the form of a load flow, which incorporates known and expected transmission constraints.

In conducting this analysis, Energyzt started with a GE-supplied database for ISO-NE. This was significantly updated using publicly-available energy market data, specifically:

- Reports issued by ISO-NE covering demand, generation and transmission
- Generating unit data from ABB' Velocity Suite ("Energy Velocity")
- Fuel price forecasts, primarily based on the U.S. Energy Information Administration ("EIA") and Energy Velocity
- Emissions allowance prices from emissions brokers

A more detailed description of key variables is provided below.

B.2.1 Demand Forecasts

In MAPS, ISO-NE electricity demand is represented by hourly demand forecasts for each ISO-NE load area. These demand forecasts are constructed using historical hourly load patterns for each area, combined with annual peak load and energy forecasts based on ISO-NE projections.

The annual energy and peak demand forecasts used in this study were based on the ISO-NE forecasts prepared as part of the 2015 CELT Report (May 15, 2015). These forecasts cover 2015 - 2024.

The ISO-NE demand forecasts are based on estimates of the underlying rate of historical electricity growth, with separate bottom–up forecasts of the effect of energy efficiency (passive demand response) and of the growth of behind-the-meter solar PV, both of which are growing substantially and reduce demand and lower overall growth rates.

For the period 2015 – 2024, energy efficiency is estimated to grow from 1,685 MW to 3,579 MW and behind the-meter-solar PV from 145 MW to 450 MW.
In the market simulations, Energyzt used the net ISO-NE demand forecasts (i.e. adjusted for energy efficiency and behind-the-meter solar PV.)[3] The average annual growth rate for net peak demand from this forecast from 2015 to 2024 is 0.5%. For annual energy demand, in the ISO-NE net forecast this remains relatively constant, effectively 0% growth from 2015 to 2024.

Projected annual energy and peak demand forecasts are shown in Figures B-1 and B-2.

[3] By using the net demand forecast, these resources do not need to be modeled explicitly.

Figure B-1: ISO-NE Peak Demand Forecast

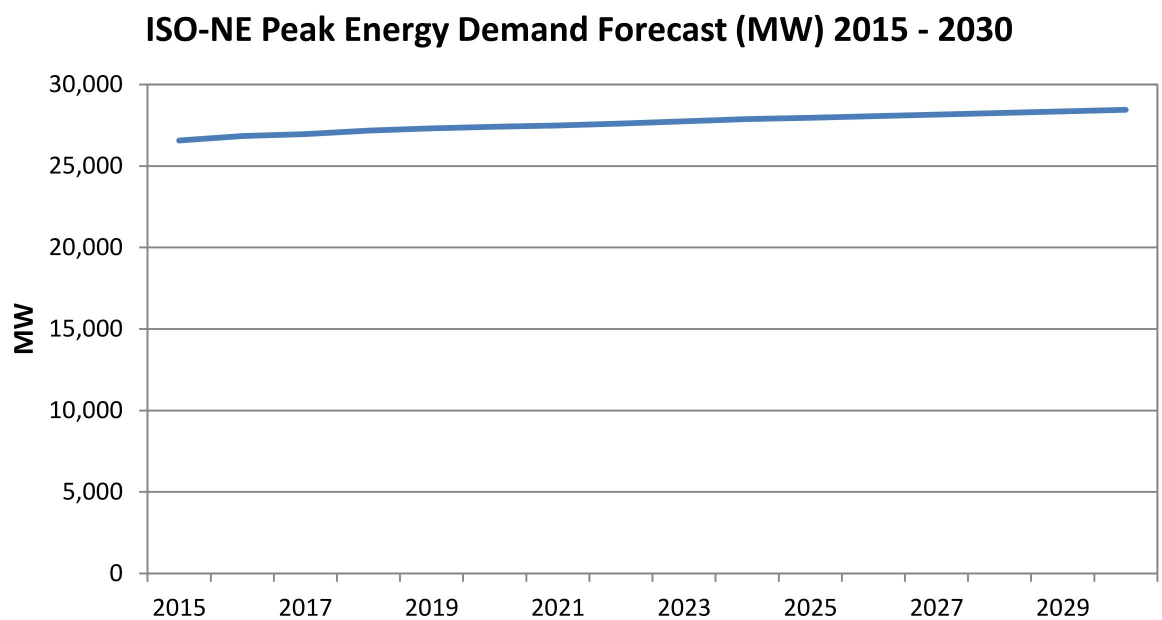
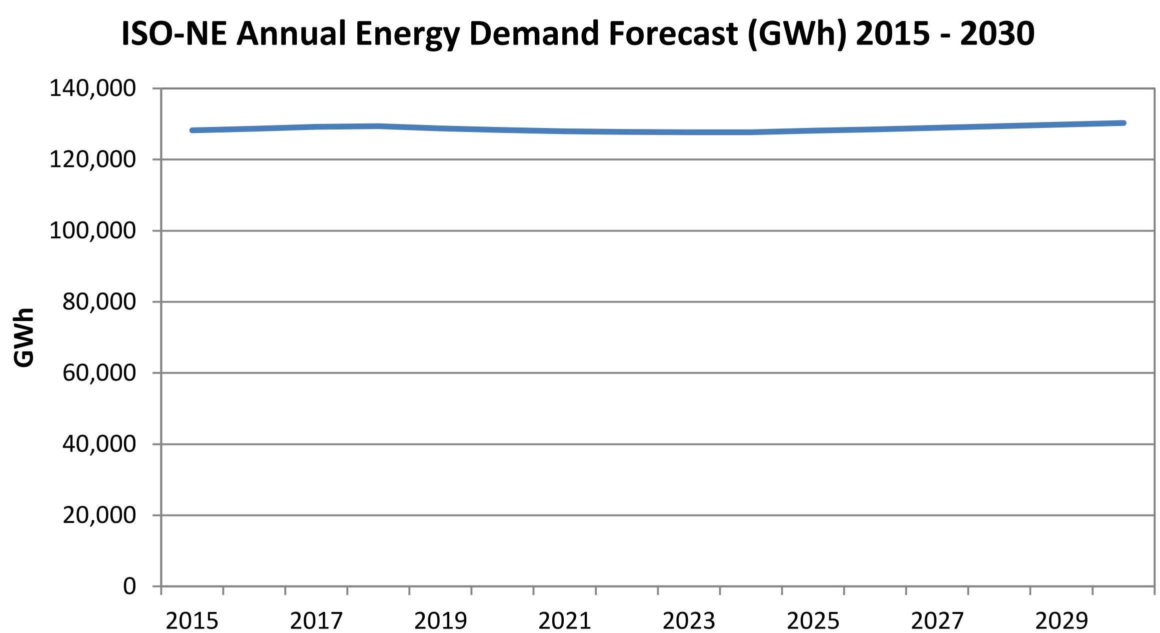


Figure B-2: ISO-NE Annual Energy Demand Forecast



Many utilities utilize demand response programs to reduce peak loads and cap energy market prices in times of high system demand or capacity shortages. The MAPS simulations include demand response resources, based on the ISO-NE forecasts of demand response as per CELT 2015 and the corresponding Forward Capacity Auction. In this analysis, Energyzt assumed active demand response of 647 MW, based on the CELT report.

B.2.2 Generation Capacity

The MAPS database used for the simulations includes the existing and expected thermal and renewable generation in the ISO-NE market over the period of the simulation. As the starting point for this analysis, Energyzt explicitly adjusted the GE MAPS database to match the existing and planned generation listed in the ISO-NE 2015 CELT as of April 2015.

The generating capacity available in each future year changes to reflect planned and likely retirements and new generation. The retirement assumptions used in the analysis are based on ISO-NE approved retirements as of April 2015. Specific new generation additions are based on new units identified in the 2015 CELT report, the ISO-NE Forward Capacity Auction 9 (February 2015) and the Energy Velocity new unit database. Typically, these specific new units are either under construction, permitted, or have PPA agreements.

In addition to these named new units, the simulation includes expected new renewable generation in ISO-NE, primarily solar and wind. New solar generation is based on the 2015 CELT report, and represents utility or merchant solar generation. Distributed solar generation – i.e. behind-the-meter PV – is not included as this has been subtracted from the ISO-NE demand forecast used in the simulations.[4]

The 2015 CELT report does not include an explicit forecast of new wind generation other than near-term units under construction. Energyzt's forecast of new wind generation assumes around 50% of the current proposals for interconnection of wind plants will proceed. This is consistent with the expectation that the majority of new wind resources will be located in Maine, where around 1,000 MW of additional wind can be added before additional transmission into the rest of ISO-NE will be needed. With respect to new hydro and biomass generation in ISO-NE, Energyzt assumes only the projects listed in the interconnection queue.

As discussed previously, the ISO-NE CELT 2015 demand forecasts have low annual growth rates over the period of the simulation because of the expected effect of energy efficiency and behind-the-meter solar PV. Nonetheless, towards the end of the period, some additional generic thermal capacity is likely to be needed to maintain ISO-NE's reserve margin at 15%. Given the nature of the ISO-NE generation system, and the addition of significant new wind capacity, Energyzt has assumed these new generic thermal additions will be gas-fired combustion turbines.

Retirements

The 2015 ISO-NE CELT report identifies announced retirements. Energyzt retires these units in the model on the projected retirement date.

[4] Total solar installations includes 1) behind-the-meter installations; 2) solar projects under construction; 3) announced solar projects; and 4) generic solar installations included as part of the build-out to meet environmental objectives such as lower emissions under RGGI.

Figure B-3: ISO-NE Plant Retirements assumed in the MAPS Model

Resource Name	Capacity (MW)	State	Retirement Date	IN EV	ISO-NE List
Norwalk Harbor 10 (3)	17	CT	6/1/17		Yes
Norwalk Harbor 1	164	CT	6/1/17		Yes
Norwalk Harbor 2	172	CT	6/1/17		Yes
Brayton Diesels 1-4 Incremental	10	SEMA	6/1/17	Yes	Yes
Brayton PT 2	258	SEMA	6/1/17	Yes	Yes
Brayton PT 1	255	SEMA	6/1/17	Yes	Yes
Brayton PT 4	455	SEMA	6/1/17	Yes	Yes
Brayton PT 3	638	SEMA	6/1/17	Yes	Yes
Wallingford Refuse	8	CT	6/1/17		Yes
Bridgeport Station 4	19	CT	7/1/16	Yes	No
Ridgewood Providence GEN 1-9	17	RI	6/1/16	Yes	No

Although other units may become uneconomic under different scenarios, we do not retire them, but let their dispatch dictate operations.

Specific New Capacity Additions

Plant additions for the ISO-NE market include those that have cleared in the forward capacity auctions as well as generic units required to balance the market to achieve a 15 percent reserve margin in the simulations. Figure B-4 identifies the new generating facilities that currently are under construction; Figure B-5 lists the new generating facilities that have been permitted.

Table B-4: New Generating Facilities Currently Under Construction

Resource Name – Under Construction	Type	Capacity (MW)	State	Operational Date
Coye Hill Wind	Wind	20.0	CT	01/01/17
Freetown Solar	Solar	5.0	MA	04/30/15
Braley Road Solar 2	Solar	2.9	MA	04/30/15
Freetown Solar	Solar	6.0	MA	05/31/15
BWC Solar (Dartmouth)	Solar	4.1	MA	12/15/15
ACE Cape Cod Solar	Solar	18.0	MA	01/15/16
ACE Boston Solar	Solar	2.0	MA	03/15/16
Saddleback Ridge Wind Project	Wind	8.6	ME	09/30/15
Oakfield Wind Farm	Wind	147.6	ME	10/31/15
WED Coventry Wind	Wind	15.0	RI	12/31/15
Block Island Wind	Wind	30.0	RI	09/30/16
Stafford Hill Solar Farm	Solar	2.0	VT	06/15/15
Coventry Solar Project	Solar	2.2	VT	07/15/15
Townshend Dam	Hydro	0.9	VT	05/31/15
Ball Mountain Hydro	Hydro	3.0	VT	06/30/15
TOTAL		**267.2**		

Figure B-5: Permitted New Generating Facilities

Resource Name - Permitted	Type	Capacity (MW)	State	Operational Date
CPV Towantic 1	Dual-fuel CC	406.6	CT	06/01/18
CPV Towantic 2	Dual-fuel CC	406.6	CT	06/01/18
Cargill Falls Hydroelectric Project	Hydro	0.9	CT	03/19/16
Wind Colebrook North	Wind	4.8	CT	01/01/16
Salem Harbor/Footprint	Gas	688.0	MA	06/01/17
Pioneer Valley Energy	GT	413.0	MA	06/30/16
East Brookfield Solar	Solar	11.0	MA	05/15/15
Ponterril Solar	Solar	3.0	MA	06/15/15

Resource Name - Permitted	Type	Capacity (MW)	State	Operational Date
Canton Mountain Wind	Wind	19.3	MA	10/31/15
Cape Wind	Wind	468.0	MA	01/01/18
Springfield Biomass Plant	Waste	38.0	ME	07/15/16
Jericho Mountain	Wind	8.6	ME	10/31/15
Pisgah Mountain Wind	Wind	9.0	ME	11/01/15
Bingham Wind Project	Wind	191.0	ME	12/01/15
Passadumkeag Windpark	Wind	42.0	ME	12/31/15
Hancock Wind	Wind	51.0	ME	12/31/15
Charlotte Solar (VT)	Solar	2.2	VT	05/15/15
Fair Haven Energy Center	Waste	34.0	VT	10/31/17
Deerfield Wind	Wind	30.0	VT	12/31/15
TOTAL		**2,826.9**		

In addition to the units under construction and permitted, Energyzt includes the following units that cleared the Forward Capacity Market.

Table B-6: New Generating Facilities Listed in Forward Capacity Market

Listed In Forward Capacity Market	Type	Capacity (MW)	State	Operational Date
West Medway Station 1	Dual-fuel GT	100	MA	6/30/18
West Medway Station 2	Dual-fuel GT	100	MA	6/30/18
Wallingford Unit 6	GT	50	CT	1/1/17
Wallingford Unit 7	GT	50	CT	1/1/17
TOTAL		**300**		

Generic Capacity Additions

In addition to announced units, longer term projections often require new additions of generic capacity to balance the system. In this case, the combination of demand growth (which is negligible) and renewable resource assumptions required to meet carbon emissions targets, very few units are required for purposes of balancing the system in the out years. Two 200 MW units are added in 2027 and 2028.

Figure B-7: Generic new capacity additions

Year	Generic Wind (MW)	Generic Hydro (MW)	Generic Biomass (MW)	Generic Solar (MW)	Generic Thermal (MW)
2015	0	0	0	78	0
2016	50	0	0	126	0
2017	100	0	0	46	0
2018	100	0	0	48	0
2019	75	0	0	45	0
2020	75	0	0	38	0
2021	75	0	0	20	0
2022	75	0	0	19	0
2023	75	0	0	19	0
2024	75	0	0	19	0
2025	75	0	0	9	0
2026	75	0	0	9	0
2027	75	0	0	9	200
2028	75	0	0	9	200
2029	0	0	0	0	0
2030	0	0	0	0	0

As opposed to six months ago when ISO-NE and state organizations projected a need for new capacity to be built immediately, winning bids in the FCM coming online before 2020 and ISO-NE's lower projected energy requirements over the longer term have mitigated the need for new gas-fired generating units. Under target reserve margins, current demand projections, and new generation under construction or announced, new generating units are not required until 2027.

The generic solar additions were included for consistency with the ISO CELT report. When combined with the behind-the-meter solar assumptions embedded in the ISO load projections, solar projects under construction, and announced solar projects, total solar additions are anticipated to be 850 MW by 2020, with another 150 MW of solar additions thereafter.[5]

Imports

ISO-NE is connected to NYISO, Ontario, Quebec and New Brunswick through six AC and DC interfaces. Power is imported and exported across these interfaces, with the magnitude of the import or export varying with the time of day and month. Historically, in recent years the average monthly net flow into ISO-NE from external pools ranged from 1,000 MW to 2,200MW.

The MAPS model used for these simulations represents just the ISO-NE market area. To ensure imports and exports are accounted for correctly, Energyzt used 2011-2013 historical data to estimate the monthly average peak and offpeak hourly flows into or out of ISO-NE for each of the six interfaces. Assuming that the transmission limits across the interfaces do not change, this avoids needing to represent the adjoining pools within the model.

B.2.3 Natural Gas Forecasts

Natural gas price forecasts were developed for a Base Case and Extreme Weather Case on a monthly or weekly basis as required for the analysis. These forecasts were prepared for each of four major natural gas pricing Hubs in New England - Algonquin City Gate, Dracut, Iroquois-Zone 2, and Dominion South. They were also prepared for Henry Hub in Louisiana and the Marcellus region in Pennsylvania. The basic drivers for these forecasts were the EIA Annual Energy Outlook 2015 Long Range Reference Case natural gas price series.

[5] Although less than the ISO-NE stated expectation of 2,000 MW of solar capacity on the system, the assumptions are consistent with ISO-NE projections.

Within MAPS, each gas-fired unit is assigned a gas price based on the pipeline/hub that serves that site.

The Base and Extreme Weather cases relied on gas price assumptions at Henry Hub and then applied "basis differentials" - differences between the prices at delivery points in New England and the Henry Hub or Marcellus points - to estimate the final delivered prices. Because of the large volatility that has been experienced in gas prices both seasonally, monthly, and even weekly (for the Extreme Weather case), the build-up of these forecasts required daily gas prices and quantities at each of the points. The historical data on delivered prices were downloaded from Energy Velocity based on EIA reports from utilities and power generators.

Base Case Assumptions

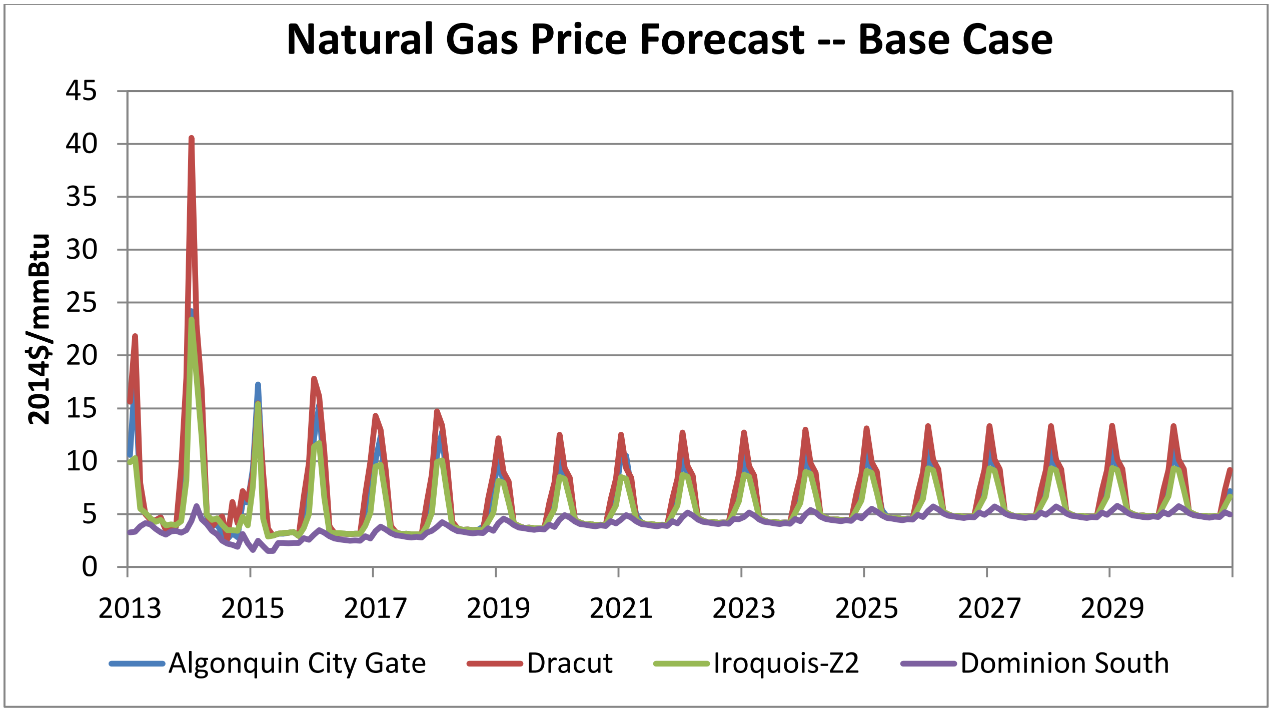
The Base Case represents a plausible future scenario with normal weather trends, pipeline capacity additions, imports of LNG, and, over time, more natural gas coming from the Marcellus Region and blending in with Gulf Coast gas shipped by the existing long-distance pipelines. Monthly price volatility was captured in the Henry Hub prices as well as the basis differentials.

Short-term and long-term price forecasts for Henry Hub were based on the EIA Short Term Natural gas Outlook (May 2015) and the AEO 2015 Reference Case (April 2015) that goes out to the year 2040. These were compared to a number of other public and private sources for reasonableness and as a quality check, and were selected because they represent well-established and publically available sources.

Historical basis differentials were calculated on a monthly basis for the last three years (2013 – 2015) from the historical data by direct calculation and then weight- averaged on a monthly and year-to-year basis. The prices are expressed in 2014$ per mmBtu delivered to each of the Hubs adjusted for inflation using deflators from the Annual Energy Outlook.

Figure B-8 shows the price paths for the key Hubs and seasonal volatility declining over time due to the new supplies of gas coming into the region due to the announced pipeline expansion projects. Underlying the projection there is an immediate reduction in winter basis differentials reflecting partial contracting for LNG and dual-fuel capability as seen last winter with another reduction to reflect the commercial operation date of an additional 600 million cubic feet per day of pipeline capacity resulting from the AIM project, Atlantic Bridge pipeline and CT Expansion. Thereafter, gas prices follow a slow growth pattern consistent with EIA's outlook and the national and global natural gas supply and demand balances.

Figure B-8: Price Paths for Key Hubs and Seasonal Volatility



Source: Energyzt Forecast, based on 2015 EIA Annual Energy Outlook

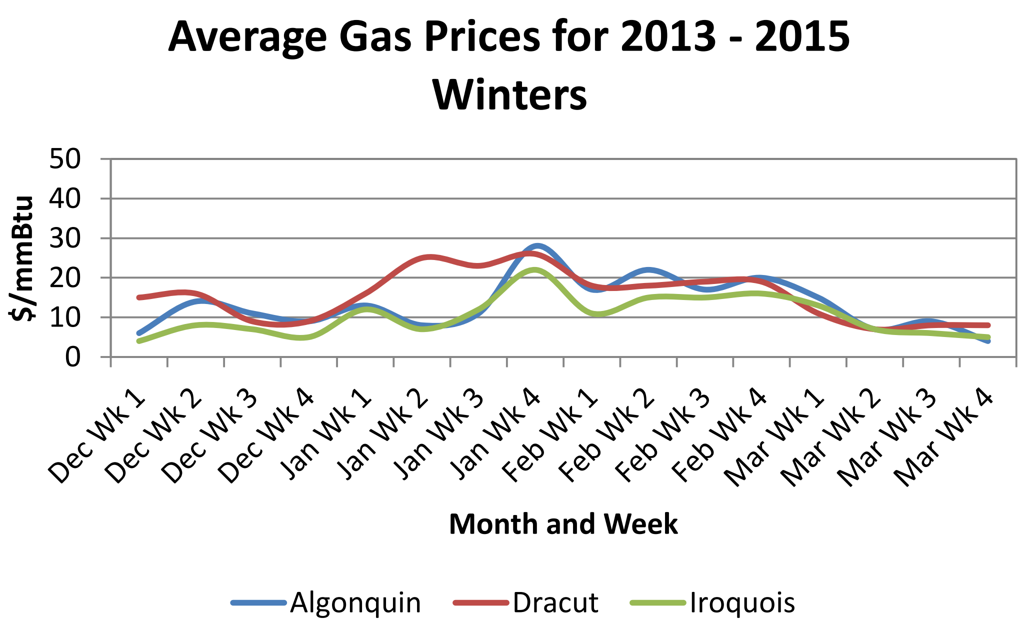
For purposes of this analysis, the basecase does not include build-out of NED or Access Northeast. These are excluded from the analysis to examine the impact of LNG contracting, dual-fuel capability and implementation of a 1,200 MW transmission line bringing non gas-fired generation from Canada in lieu of pipeline build-out. As a result, the gas price projection may be higher than other projections that incorporate these projects into their forecasts.

Extreme Weather with No LNG Case

The alternative gas price scenario reflects severe weather patterns (extreme cold, snowy periods, series of new storms coming into the region) and minimal LNG contracting as occurred during the past three winters. To capture this, historical gas price analysis was conducted on a week-by-week basis (using daily data) for each of the four major Hubs to estimate the actual prices that in some cases reached $60 to $70 per mmBtu (or more) for a few days. Moderating effects of the AIM pipeline capacity, LNG imports and the less expensive and abundant Marcellus gas moving into the New England region over existing pipeline capacity was not included in this case.

Figure B-9 illustrates the weekly price behavior reaching for short periods on time $25 - $30 per mmBtu on an average weekly basis.

Figure B-9: Average Weekly Prices for Winters 2013 - 2015



Source: Energyzt Forecast, based on 2015 EIA Annual Energy Outlook

B.2.4 Coal Prices

Coal price forecasts were developed on a plant-by-plant basis for New England using actual historical price series and the US Energy Outlook AEO 2015 reference case for steam coal prices for New England. Specific coal plants assumed to be in operation for at least some portion of the forecast time-horizon include the following:

- Bridgeport Harbor
- Brayton Point
- Merrimack
- Schiller

Some or possibly all of these plants will be closed or mothballed in future years because of environmental regulations in the New England states, the proposed Clean Power Plan, and low natural gas prices. Our analysis only retires those that have been announced, letting the model to dispatch remaining units as would be economic.

Two data sources were used for historical information for mine-mouth coal prices, heat and emissions content, transportation costs, and final delivered coal prices at the plant:

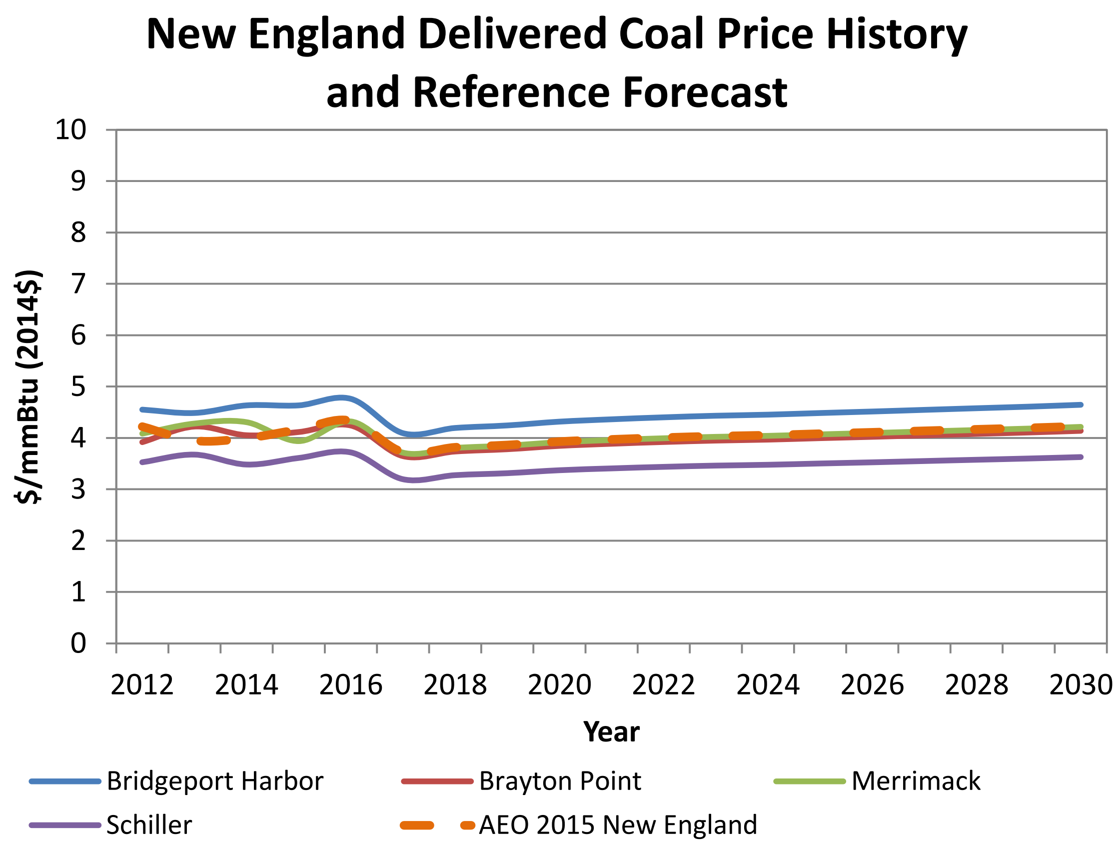
- A coal database from Energy Velocity (Coal Prices and Operations) based on government reported data from FERC 423 and EIA 923 forms

- EIA 923, a non-mandatory form and therefore subject to more estimates but considered by Ventyx to be the most accurate source.

After analysis and comparisons, historical prices from these two sources were very consistent. Coal for New England plants was almost entirely bituminous coal from Central Appalachia, shipped by rail, and very small amounts of sub-bituminous coal imported from Indonesia.

Figure B-10 shows the New England steam coal price forecast from the EIA AEO 2015 Long Range reference case that were then applied to act as a proxy driver for the historical prices out into future years on an annual basis to the year 2030.

Figure B-10: New England Delivered Coal Price History and Reference Forecast



Source: Energyzt Forecast, based on 2015 EIA Annual Energy Outlook

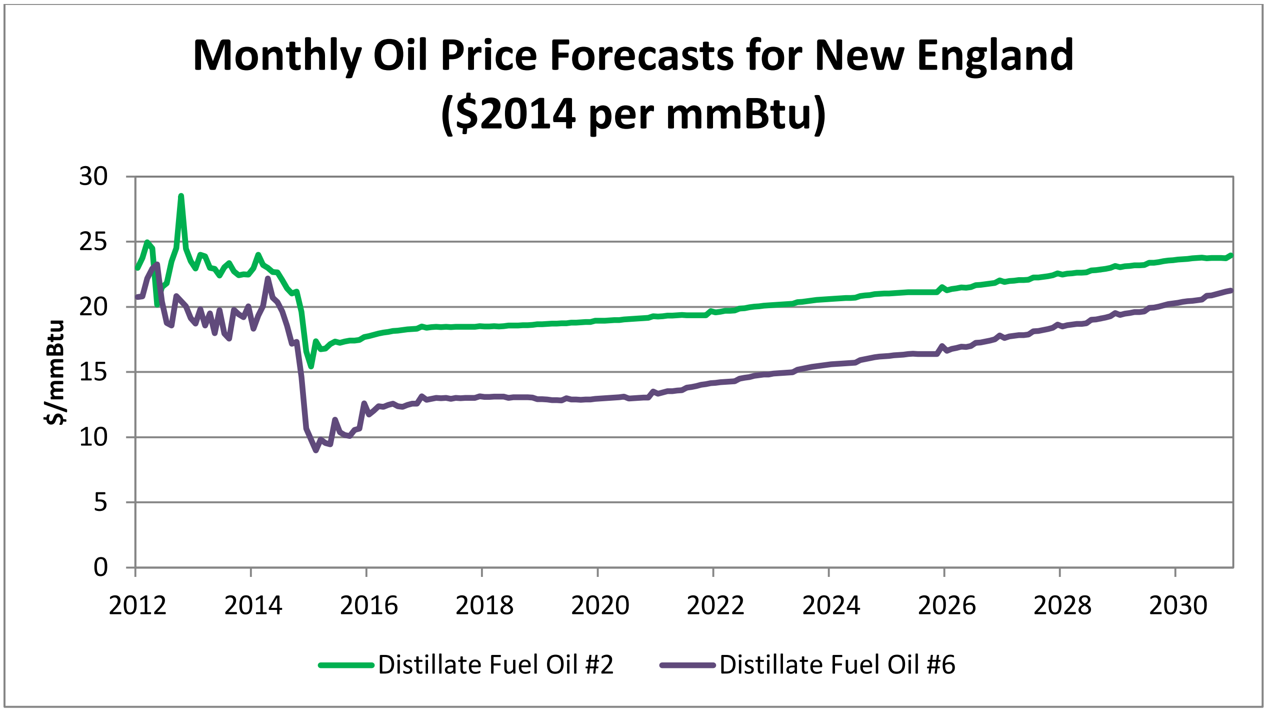
B.2.5 Oil Price Forecasts

Oil price forecasts were needed in this project for both providing estimates to fossil fuel generation units burning oil and also as input into the decision for duel-fueled units that can use either natural gas or oil based on price and availability. For this reason two oil price series were developed for New England:

- Light fuel oil that was assumed to be #2 distillate fuel oil (the primary petroleum product used in New England)
- Heavy fuel oil that was assumed to be #6 residual-fuel oil.

Monthly historical prices were obtained from Energy Velocity for each power plant in New England that consumed oil over the last five years. Future prices were then estimated on an annual basis using the EIA AEO 2015 Long Range Reference Case for the #2 fuel oil and #6 residual-fuel oil price series, as well as by reference to the Chicago Mercantile Exchange (CME) future price strip for oil. Annual prices for future years were then converted to monthly prices using historical intra-year variations. As a point of reference, the EIA Long Range forecast showed crude oil prices (expressed in 2013 constant dollar terms) reaching $83/barrel in 2020 and over $100/barrel by 2025. Monthly price series were expressed in 2014$ per mmBtu delivered to New England and adjusted for inflation using deflators from the Annual Energy Outlook (Figure B-11).

Figure B-11: Monthly Oil Prices for New England



Source: Energyzt Forecast, based on 2015 EIA Annual Energy Outlook

B.2.6 Emissions

Each coal, gas, and oil fired unit in the MAPS database is set up with an emission rate for NO_X, SO_2, and CO_2 based on the historical emissions from that unit. These emission rates depend on the fuel, the type of unit and any emission control equipment for NOx or SO_2 that has been fitted. Renewable generation and nuclear units do not have emissions.

The Cross State Air Pollution Rule (CSAPR) which regulates NOx and SO_2 emissions from thermal generation does not apply to the ISO-NE market, as the six states in New England were not included in the Rule. However, the prior existing SO_2 (Acid Rain) legislation is still in effect. The SO_2 prices used in the MAPS model are very low and were based on current market forecasts as of March 2015.

There are currently no Federal regulations that apply to CO_2 emissions. RGGI, the Regional Greenhouse Gas Initiative, includes all six of the states in the ISO-NE market. The RGGI prices used in the MAPS model were based on the RGGI Auction 26 results (December 5, 2014).[6]

Figure B-12: Emissions Allowance Price Forecast

Program	CSAPR			Acid Rain	RGGI
	NOX - Ozone Season ($/ton)	NOX - Annual ($/ton)	SO_2($/ton)	SO_2 ($/ton)	CO_2 ($/ton)
2015	0	0	0	0.50	5.20
2016	0	0	0	0.50	5.33
2017	0	0	0	0.50	5.47
2018	0	0	0	0.50	5.61
2019	0	0	0	0.50	5.75
2020	0	0	0	0.50	5.90
2021	0	0	0	0.50	5.90
2022	0	0	0	0.50	5.90
2023	0	0	0	0.50	5.90
2024	0	0	0	0.50	5.90
2025	0	0	0	0.50	5.90
2026	0	0	0	0.50	5.90
2027	0	0	0	0.50	5.90
2028	0	0	0	0.50	5.90
2029	0	0	0	0.50	5.90
2030	0	0	0	0.50	5.90

Source: RGGI prices are based on Auction 28 (December 5 2015). SO_2 prices are based on market forecasts in March 2015

[6] The current 2015 clearing price is $0.20 higher, from Auction 28 (June 3, 2015). This will not significantly alter the results of the simulations

B.2.7 Transmission

The MAPS model used for this analysis contains a summer peak load flow that represents the 2014 load flow case developed by ISO-NE. Within the GE MAPS model, transmission line limits are based on the actual ratings provided in the ISO-NE load flow case. In addition, flow gates, interface limits, and contingencies are based on a variety of sources, including:

- Documentation provided by GE MAPS
- Recent nomograms posted on various ISO/RTO websites
- Recent Regional Transmission Assessments published by local transmission providers, RTOs, ISOs, or ISO-NE

B.3. SCENARIOS

B.3.1 Canadian HDVC transmission project

There has been considerable discussion over the last decade of the potential benefits for ISO-NE of importing hydro power from Canada, in a manner similar to the existing Phase II DC transmission line that runs from Quebec to Massachusetts.

In the Base Case simulations, there are no additional import paths other than those that currently exist. An alternative scenario assumes a 1,200 HVDC transmission line is added by 2020 into New England.

Given the significant amount of additional solar and wind power that already is included in the analysis to meet environmental policy and emissions targets, the simulation assumes that imports will only occur during peak hours when it is most valuable to ISO-NE.

B.3.2 Dual-fuel Units

There are roughly 6,200 MW (winter capacity) of existing thermal units in ISO-NE that can also run either natural gas or fuel oil (FO2 or FO6). To investigate the implications and potential for using dual-fuel units to relieve pressure on gas supplies, particularly in winter months, these units were set up in MAPS to choose oil-fired generation when this was less expensive than gas. As MAPS operates on a weekly commitment and dispatch cycle, this decision was made for a week at a time. It was assumed that heat rates and operating costs remained the same when running on gas or oil. Emissions rates were adjusted to reflect the fuel being utilized.

New generic units and the majority of the planned new thermal additions (see earlier tables) were also assumed to be dual-fuel capable and were also set up appropriately.

Figure B-13: ISO-NE Existing Dual-fuel Units

Plant Name	Unit Type	Net Summer Capacity MW	Net Winter Capacity MW	Primary Fuel	Secondary Fuel
Cleary Flood	CC	108	106	NG	FO2
Dexter Windsor Locks	CC	51	61	NG	FO2
Fore River	CC	688	837	NG	FO2
Kendall Square Station	CC	209	226	NG	FO2
Kleen Energy Project	CC	622	623	NG	FO2
L Energia Facility	CC	75	78	NG	FO2
Manchester Street	CC	149	170	NG	FO2
Manchester Street	CC	154	170	NG	FO2
Manchester Street	CC	149	170	NG	FO2
NEA Bellingham Cogeneration Facility	CC	264	336	NG	FO2
Newington Power Facility	CC	522	560	NG	FO2
Pawtucket Power Associates	CC	54	57	NG	FO2
Pittsfield Generating Co LP	CC	154	186	NG	FO2
Stony Brook (MA)	CC	305	366	NG	FO2
Bucksport Mill	GT	157	183	NG	FO2
Dartmouth Power	GT	21	23	NG	FO2

Plant Name	Unit Type	Net Summer Capacity MW	Net Winter Capacity MW	Primary Fuel	Secondary Fuel
Associates					
Pierce	GT	74	95	NG	FO2
Verso Androscoggin	GT	45	56	NG	FO2
Verso Androscoggin	GT	43	54	NG	FO2
Verso Androscoggin	GT	43	55	NG	FO2
Waters River	GT	16	22	NG	FO2
Waters River	GT	29	40	NG	FO2
Waterbury	GT	96	99	NG	FO2
West Springfield	GT	37	47	NG	FO2
West Springfield	GT	37	47	NG	FO2
Brayton PT	ST	435	446	NG	FO2
Mystic	ST	575	560	NG	FO6
New Haven Harbor	ST	448	453	NG	FO2
West Springfield	ST	94	100	NG	FO6

B.4. COST BASIS

All cost data – fuel, allowance and unit operating costs - in the MAPS simulation is represented as 2014 real dollars. Estimated electricity prices and revenue outputs from the model also are reported in 2014 real dollars.