



REPORT

Winter Reliability Analysis of New England Energy Markets

Prepared for:
New England Power Generators Association

Prepared by:
Energyzt Advisors, LLC

October 2014

TABLE OF CONTENTS

EXECUTIVE SUMMARY

1	INTRODUCTION	1
2	NEW ENGLAND ENERGY MARKETS ON JANUARY 7, 2014.....	2
2.1	Gas Market Conditions	2
2.2	Power Market Conditions	5
3	WINTER RELIABILITY ANALYSIS.....	8
3.1	Natural Gas Available to New England.....	9
3.1.1	Pipeline Capacity.....	9
3.1.2	LNG Capacity	10
3.1.3	Peak Gas Demand	12
3.1.4	Gas Available for Generation.....	13
3.2	Generating Capacity	14
3.2.1	Gross Generating Capacity	14
3.2.2	Capacity Additions	15
3.2.3	Capacity Retirements.....	15
3.2.4	Forced Outages	16
3.2.5	Derate Factors for Intermittent Resources	16
3.2.6	Fuel Limits.....	18
3.3	Imports of Power into New England.....	18
3.4	Peak Power Demand	20
3.5	Summary of Winter Peak Base Case Assumptions	21
4	ANALYSES AND RESULTS	22
4.1	Expected Reserve Margins under Winter Peak Base Case	23
4.2	Sensitivity Analyses.....	24
4.2.1	LNG Sensitivity	26
4.2.2	AIM Schedule Sensitivity	27
4.2.3	Gas Demand Growth Sensitivity	27
4.2.4	Heat Rate Sensitivity	28
4.2.5	Forced Outage Rate Sensitivity	28
4.2.6	Renewable Derate Sensitivity	29
4.2.7	Import Sensitivity.....	30
5	CONCLUSIONS	30

Winter Reliability Analysis of New England Energy Markets

EXECUTIVE SUMMARY

New England is not facing a near-term energy infrastructure crisis. As shown this past winter and through the analyses summarized in this report, New England has adequate energy infrastructure to meet its winter reliability objectives now and into the near future. To the extent any centralized effort is required, it would be to ensure adequate planning and commercial arrangements so as to optimize use of existing infrastructure. Optimizing what New England already has will ensure reliability for the region and provide time for private investors to make long-term infrastructure investment.

CASE STUDY – January 7, 2014

This past winter experienced a series of extreme conditions, with January 7, 2014, standing out as a critical day that prompted a FERC request for information from ISO New England. Yet, as the response to FERC shows, despite high demand for both power and gas along with an emergency outage on the Texas Eastern Pipeline, reduced power imports and 500 MW of emergency sales from New England to PJM, target reserve margins were met. Reliability was not compromised on that day this past winter, despite extraordinarily adverse system conditions, indicating that New England has enough energy infrastructure to meet winter peak demand.

WINTER RELIABILITY ANALYSES

To assess reliability in the near term, a modeling exercise is required. Incorporating gas availability into the existing and projected electricity supply stack and comparing to projected winter peak demand, we assessed reserve margins under a winter peak base case. Incorporating a number of conservative assumptions to reflect conditions under a winter peak demand day for natural gas and electricity, the winter reliability analysis indicates more than adequate reserve margins. So long as the energy infrastructure is operating at reasonably expected levels of availability, the existing infrastructure inventory is adequate to meet demand under extreme weather conditions.

SENSITIVITY ANALYSES

On top of the winter peak base case, we ran a number of scenarios to identify key risk factors and impacts on reliability if infrastructure were not available at expected levels of operation. Even under a number of incrementally challenging events, the ISO New England system remains robust. Only a complete lack of LNG, the region's current insurance policy for meeting peak natural gas demand needs, forces the system to reserve margins below target levels. With adequate infrastructure, the system requires advanced planning and commercial arrangements to optimize existing resources in order to ensure reliability while private investors pursue market-based infrastructure solutions.

Winter Reliability Analysis of New England Energy Markets

1 INTRODUCTION

Electric utility reliability in New England has come under scrutiny given this past year's unusually cold winter. As an increasing amount of the region's electric generating capacity is fired by natural gas, there is an expressed concern among certain constituents that demand for heating will make natural gas unavailable for power generation. As a result of this concern, multiple proposals have been discussed, including an approach by the region's governors, to increase both natural gas and electric power transmission into New England. Rather than rely on private parties risking private capital, however, government proposals recommend using region-wide tariffs assessed on regulated end-users to support these large infrastructure investments.¹

This report examines the extent to which electric reliability in New England is threatened over the near term. Our fundamental analysis of the existing infrastructure adjusted for proposed retirements indicates that the market operated by ISO New England works very well and energy infrastructure is sufficient in the near-term to address winter reliability concerns. Despite a conflux of extreme events, the New England power system was able to meet the reliability needs of a challenging winter in 2014. And, except under the most severe conditions where existing infrastructure is simply unavailable, it should be able to meet targeted winter reserve margins for at least the next four years as new infrastructure is being built. Already, market participants actively are evaluating and planning new infrastructure investments into New England, providing a number of market-based solutions for longer-term reliability.

Our analysis starts with a review of actual power market operations on January 7, 2014, an exceptionally cold day in New England that resulted in high demand and high prices for both gas and power. Despite challenging conditions, the electric power system was able to meet its load and reserves obligations on that day. Next, we analyze what expected reserve margins should be in New England over time as new capacity is added and existing units are retired. Imposing a number of adverse conditions on the peak winter day baseline, ISO New England reserve margins can be expected to remain above target levels so long as appropriate commercial arrangements are in place to optimize the use of existing infrastructure.

As a result of these analyses, we conclude that New England has adequate energy infrastructure to meet near term reliability requirements so long as such infrastructure is available and optimized. Therefore, we recommend pursuit of planning and commercial arrangements that ensure the availability of existing

¹ 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).

energy infrastructure as private investors pursue longer term infrastructure investments in response to price signals.

2 NEW ENGLAND ENERGY MARKETS ON JANUARY 7, 2014

The first week of January 2014 experienced extremely cold weather across New England and surrounding regions, attributed to the so-called Polar Vortex. Beginning on January 2, 2014, a cold front moved through the area leading to freezing temperatures in the single digits (Fahrenheit) throughout most of New England. The next few days saw a reprieve with lows in the 50s. By January 7th, however, the cold weather returned, with temperatures plummeting again to single digit lows. Based on data from the ISO New England, this time period was among the coldest 5% of all days over the past twenty years.²

Because of the cold weather, demand was high for natural gas from both heating customers and electric power generators. This increased demand resulted in natural gas price spikes of up to \$38 per MMBtu at the Algonquin city gate compared to more typical values of \$3 to \$6 per MMBtu during unconstrained periods.³ Moreover, gas was unavailable for some generators in certain periods, testing the region's electric power reliability. For some observers, this period, especially January 7, 2014, highlighted the dependence of the region's power system on natural gas and has been used to justify government activity in energy infrastructure markets via public implementation of cross-sector subsidization of private gas and power infrastructure investment. In reality, January 7 highlights a market-based system that was constrained but worked, challenging the need for government intervention.

2.1 Gas Market Conditions

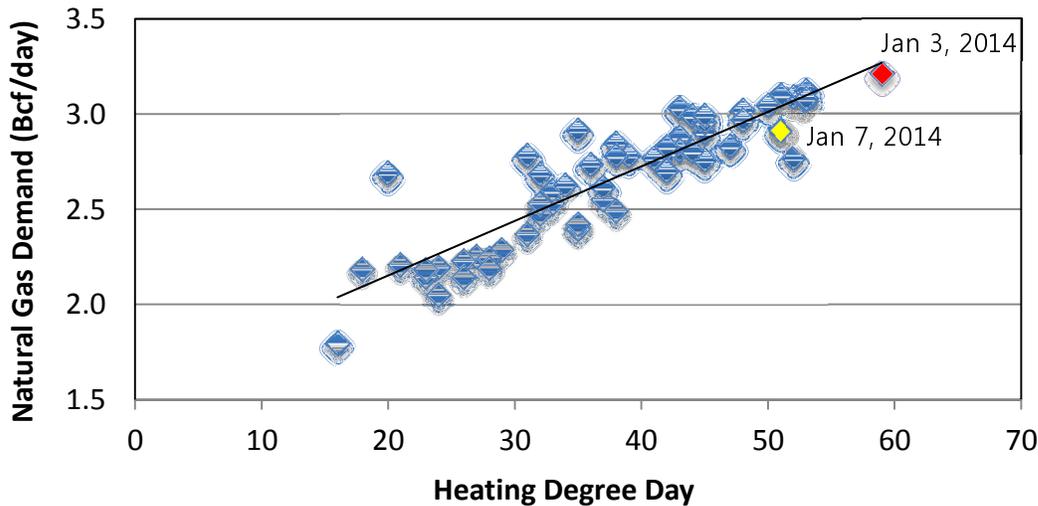
In New England natural gas is used for heating by residential and commercial customers and as feedstock and process heat for industrial operations. These customers generally take firm service from local gas distribution companies ("LDCs"), meaning the LDCs plan their systems, including purchases of firm interstate gas pipeline capacity, to meet expected winter peak demand when temperatures cool and heating requirements rise. As can be seen in Figure 1, 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

² ISO New England, "January 2014 FERC Data Request," p. 1 (www.iso-ne.com/pubs/spcl_rpts/2014/iso-ne_responseferc%20data%20request_january%202014.pdf accessed 8/14/14)

³ US Energy Information Administration, "Northeast and Mid-Atlantic power prices react to winter freeze and natural gas constraints" (www.eia.gov/todayinenergy/detail.cfm?id=14671 accessed 8/14/14)

mean temperature falls below 65° F). As temperatures plummeted in January 2014 (meaning a higher heating degree day value), demand for gas increased.

Figure 1: LDC Gas Demand in New England (Billion cubic feet per day)



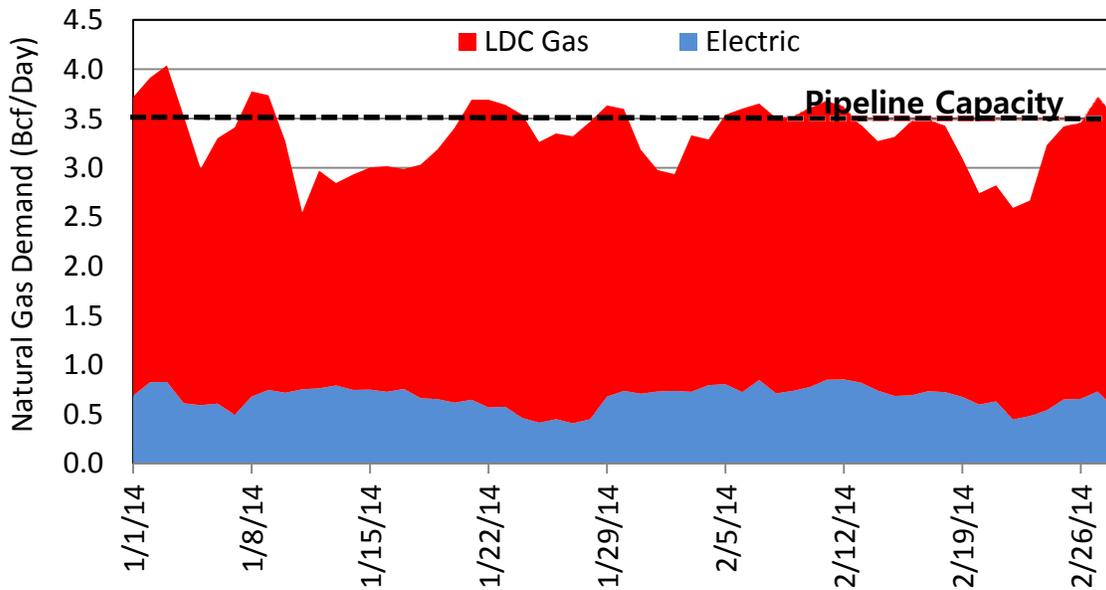
Source: Energyzt analysis of Ventyx, Energy Velocity Suite

Approximately 40% of electric power generators in New England consume natural gas as their primary fuel based on winter seasonal claimed capacity. An additional 10% can use natural gas as a secondary fuel.⁴ Unlike natural gas demand for heating which peaks in the winter, electric power demand is more closely related to cooling needs and peaks on an annual basis during the summer months. The seasonal differential between the natural gas demand peak and the electricity peak tends to mitigate supply risk in the winter as winter peak generally represents a lower level of demand for electric power. 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 power prices are highest, but subject to curtailment in winter when the opportunity cost of not being able to run is lower. Such curtailments occurred during January 2014.

The following chart summarizes consumption of natural gas by LDC customers and electric power generators during the months of January and February 2014. For the purposes of this analysis, total deliveries from interstate pipelines to residential, commercial, and industrial customers were used as an estimate for LDC firm demand.

⁴ ISO New England, "CELT Report 2014 – 2023 Forecast Report of Capacity, Energy, Loads, and Transmission" 2.1 Generator List (www.iso-ne.com/trans/celt/report/ accessed 8/14/14)

Figure 2: Natural Gas Demand in New England (Bcf per day)



Source: Energyzt analysis of Ventyx, Energy Velocity Suite

Demand for natural gas from all customers peaked at 4.0 Bcf on January 3. For the months of January and February, total gas demand exceeded the installed interstate natural gas pipeline capacity of 3.569 Bcf on 16 days (around 25% of the time), indicating additional capability.⁵ The natural gas system was able to deliver quantities in excess of pipeline capacity due to the availability of the LNG storage and delivery infrastructure.⁶

The peak gas day for LDC customers this past winter was January 3, 2014, with 3.21 Bcf of demand. On the critical power day of January 7, 2014, LDC customer demand was lower, at 2.91 Bcf.⁷ Both of these values are below the installed capacity of the interstate natural gas pipelines, meaning that, in principle, there was still excess pipeline capacity available to serve power generators.

In other words, despite high demand by LDC customers, natural gas was still available for electric generation throughout January and February. This was true even despite a force majeure event on the Texas Eastern Pipeline System that

⁵ Energyzt analysis of Ventyx, Energy Velocity Suite

⁶ A more complete description of New England's natural gas infrastructure, including proposed capacity additions, is provided in Section 3.1 of this report.

⁷ Energyzt analysis of Ventyx, Energy Velocity Suite

reduced capacity by 0.575 Bcf on January 7, 2014.⁸ On average over the months of January and February 2014, 0.673 Bcf of natural gas was available for electric power generation. On the coldest days of January 3rd and 7th, 0.825 Bcf and 0.494 Bcf, respectively, were available for power generation.⁹

The availability of 0.494 Bcf of gas for power generation on January 7th translates into approximately 4,000 MW of generation based on an average natural gas heat rate of 8,000 Btu/kWh and an operating cycle of 16 hours (these assumptions are detailed in Section 3.2 below). This calculation is consistent with the values presented by ISO New England in the Data Request which indicated that that actual natural gas generation on peak was 4,000 to 5,000 MW.¹⁰

Although there may have been winter days when available gas supply could only support lower levels of electric generation capacity, such days did not correspond to peak power demand. Existing LNG infrastructure in New England helps to mitigate the risk of coincident peak demand days.

2.2 Power Market Conditions

ISO New England 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 and operating reserves markets. The ISO also is responsible for scheduling imports and exports of power across the region. The following table is reproduced from the FERC Data Request and summarizes the generating capacity and imports that were available at the peak hour on January 7, 2014, to meet system load and reserve requirements.

⁸ ISO New England, "January 2014 FERC Data Request," p. 3

⁹ Energyzt analysis of Ventyx Energy Velocity Suite

¹⁰ ISO New England, "January 2014 FERC Data Request," pp. 7 - 9

Figure 3: ISO New England Capacity Analysis – January 7, 2014

	MW
Capacity Supply Obligation (CSO)	30,703
Capacity Additions > CSO	2,980
Available Dispatchable Loads	-
Outages and Reductions	(4,677)
Generation Unavailable Due to Start Time	(5,921)
NYISO Purchases	(1,480)
NBSO Purchases	638
HY Purchases	1,594
Total Available Capacity	23,836
ISO-NE Load	21,432
Operating Reserve Requirement	2,360
Net Capability Required	23,792
Capacity Margin	44

Source: ISO New England, "January 2014 FERC Data Request" page 9. Totals in the table may not sum due to rounding

The ISO 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 on by ISO New England. There is a system of penalties if parties are unable or unwilling to meet their CSO. The FCM therefore provides a market-based mechanism, in addition to market-based energy prices, to ensure that generation capacity and load response are available when most needed (i.e., during extreme weather conditions). Market participants who are not paid to accept a CSO are still able to provide capacity when required by responding to day-ahead or real-time energy markets prices.

On January 7, 2014, ISO New England 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.

From this total, ISO New England 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.¹¹ Additionally, there were up to 1,280 MW of gas fired generation that could not affirm 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.”¹²

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 New England. Net of these outages and scheduling constraints, a total of 23,085 MW of in-region capacity was available to serve peak demand.

During the peak hour, ISO New England reports net imports of 752 MW. This is comprised of imports of 1,594 MW from Hydro Quebec and 638 MW from New Brunswick net of exports to the New York Independent System Operator (“NYISO”) of 1,480 MW. Combining in-region resources with net imports produces total available capacity of 23,836 MW.

ISO New England load during the peak hour was 21,432 MW. Generators were dispatched to meet this load and to supply an additional reserve margin of 2,360 MW. This reserve capacity was either synchronized or capable of being quickly synchronized in the event that a significant outage of a generator or transmission tie line had occurred. 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 several severe contingencies were to occur. For the peak hour of January 7, 2014, ISO New England calculated required reserves as approximately 11% of load.

The net result was that ISO New England 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. The FERC Data Request, however, provides enough detail to put the surplus capacity numbers in a different perspective.

Looking deeper into the net imports with neighboring regions reveals that the New England power system was able to meet its changing needs and still ensure reliable operations. In its day ahead planning, ISO New England had expected to import 1,100 MW from New York in addition to approximately 2,200 MW from Canada.¹³ 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. This is a swing of approximately

¹¹ ISO New England, “January 2014 FERC Data Request,” p. 10

¹² ISO New England, “January 2014 FERC Data Request,” p. 2

¹³ ISO New England, Daily Capacity Status worksheet (http://www.iso-ne.com/sys_ops/mornrpt/daily_capacity_status.xls accessed 8/14/14)

2,600 MW that the existing system under constrained conditions was able to support while still maintaining available reserves.

ISO New England had approximately 6,000 MW of capacity in the region that it had not scheduled for dispatch. Depending on how many of these units had available fuel, this capacity potentially represents a significant margin of safety for power system reliability. The question of how much of this capacity would have been available on-peak if scheduled is critical to understanding regional reliability; however, it is unanswered in ISO New England's response to FERC.

Moreover, it is unclear from the available data how the situation would have been different had some of the recently announced generator retirements occurred before January 2014. At a minimum, ISO New England would have committed a different set of resources for dispatch. Additionally, the 500 MW in emergency sales to PJM may not have been possible, freeing up this capacity to serve in-region demand and meet reserve requirements. The analysis described in Section 3 is intended to provide insight into the question of how reliability can be met over the next four winter seasons, after a number of anticipated unit retirements occur.

In summary, rather than describe a fragile system that requires public intervention, analysis of January 7, 2014, shows quite the opposite. New England was not only able to meet its own reliability obligations on a cold day with limited gas and a sudden loss in expected imports, it was also able to contribute to regional reliability by making New England power available for export to meet emergency conditions in neighboring regions.

Furthermore, during the actual peak gas demand day of January 3, 2014, ISO New England had more than enough generation to meet its reliability requirements, indicating that the challenge comes not from a lack of inventory of existing infrastructure, but from contingencies surrounding availability of regional infrastructure and resources in neighboring regions.

3 WINTER RELIABILITY ANALYSIS

ISO New England's response to the FERC Data Request shows how the power system was able to meet demand and reserves on a day that included the challenges of limited gas and loss of imports from neighboring markets. What is unclear from the available information about that day is how much of the approximately 6,000 MW of uncommitted capacity could have been available on that day or could be available on a similar day in the future. Moreover, there are known capacity additions and retirements in both pipeline and power generation infrastructure that will impact the reliability of New England's energy markets. In order to analyze these issues, we assessed alternative scenarios using a more generalized electric reliability model.

The general methodology behind this model is fairly straightforward:

- **Step 1:** Calculate how much natural gas should be available for generation given pipeline capacity after meeting peak LDC gas demand.
- **Step 2:** Add other generating capacity (properly adjusted for retirements and outages) and power imports to the available gas-fired capacity.
- **Step 3:** Subtract peak power demand.

The result is excess capacity that could be used to meet reserve requirements.

There are two important caveats to this analysis. First, the analysis is conducted on a region-wide basis, not accounting for the locational nature of power operations, including import and export constrained zones within New England. Second, the analysis does not simulate gas demand and availability on an individual pipeline basis. In other words, constraints on the flow of gas and electricity within ISO New England may create local shortages even though delivery of these commodities into the region is unconstrained. That said, the analysis does provide an inventory of the infrastructure that currently is available and is projected to be available in the near future and analyzes conditions under which that infrastructure may be challenged.

This section describes the analyses used to determine appropriate inventory parameter values for the winter seasons through winter 2017/18. The next section describes the sensitivity scenarios and associated results.

3.1 Natural Gas Available to New England

Infrastructure delivering gas to New England includes interstate pipelines and LNG resources, described in more detail below.

3.1.1 Pipeline Capacity

The following table summarizes interstate pipeline capacity into New England.¹⁴

¹⁴ Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs" p. 19 by ICF International, <http://psb.vermont.gov/sites/psb/files/docket/7862relicense4/Exhibit%20EN-JT-15.pdf> accessed 8/14/14

Figure 4: Interstate Natural Gas Pipelines into New England

Interstate Pipeline	Capacity Bcf per day
Algonquin Gas Transmission	1.087
Iroquois Gas Transmission	0.220
Tennessee Gas Pipeline	1.261
Portland Natural Gas Transmission	0.168
Maritimes and Northeast Pipeline	0.833
Total	3.569
Algonquin Incremental Market (AIM) (2016)	0.350
Total Including AIM	3.919

Source: Energyzt Analysis. Maritimes and Northeast Pipeline includes injections from the Canaport LNG facility.

There is approximately 3.569 Bcf per day of pipeline capacity to deliver natural gas into New England. A planned capacity addition by Algonquin, the Algonquin Incremental Market or AIM project, will increase deliverability by approximately 10% or 0.35 Bcf per day by the winter of 2016/17. AIM is been included in our winter peak base case starting that winter.¹⁵

A number of additional privately-sponsored pipeline expansion projects also are in the works. Tennessee Gas Pipeline recently announced an open season which, if completed, could add gas delivery capacity of up to 2.2 Bcf per day into New England.¹⁶ These proposed projects have not been included in the winter peak base case analysis even though they could proceed without government intervention in the event the market recognizes the value of this additional capacity.

3.1.2 LNG Capacity

As described above, on sixteen days during the months of January and February 2014, serviced gas demand from all customers was in excess of the 3.569 Bcf per day of pipeline capacity into New England. The incremental gas on those days, and at other times throughout the winter, came from the significant liquefied natural gas

¹⁵ "Algonquin Incremental Market (AIM) Project" by Spectra Energy (www.spectraenergy.com/Operations/New-Projects-and-Our-Process/New-Projects-in-US/Algonquin-Incremental-Market-AIM-Project accessed 8/14/14)

¹⁶ "Tennessee Gas launches open season for New England pipe expansion" by Platts (www.platts.com/latest-news/natural-gas/houston/tennessee-gas-launches-open-season-for-new-england-21222525 accessed 8/14/14)

(“LNG”) infrastructure that is in place in New England. This infrastructure is summarized in the following table.¹⁷

Figure 5: LNG Infrastructure in New England

Facility	Storage bcf	Deliverability bcf per day
Everett	3.5	0.715
LDC Peak Shavers	16	1.400
North East Gateway	n/a	0.600
Neptune	n/a	0.750
Total		3.465

Source: Energyzt Analysis

The primary LNG resource in the region is the Everett facility which can store 3.5 Bcf of LNG and has the capacity to gasify (i.e., regas) and deliver a maximum 1 Bcf per day into the Boston area on a discrete basis and 0.715 Bcf of gas on a continuous basis.¹⁸ 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 plant.¹⁹ 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 Bcf per day into New England.

¹⁷ Assessment of New England’s Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs” p. 19 by ICF International

¹⁸ 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, accessed 8/14/14)

¹⁹ GDF Suez, <http://www.suezenergyna.com/lng-operations/>

This table does not include the Canaport facility in Saint John, New Brunswick since deliveries from that facility are among the sources of supply delivered by the Maritimes and Northeast Pipeline.²⁰

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 Bcf of storage at these facilities and have delivery capability of approximately 1.4 Bcf per day.²¹ The delivery capability from Everett to these peak shavers is estimated to be 0.1 Bcf per day via trucks.²² In total, deliverability from the existing LNG facilities (on-shore and off-shore) is around 3.5 Bcf per day.

Much attention has been paid to the long-term economics of LNG in New England. With the growth of low cost, unconventional gas reserves such as the Marcellus Shale, the economics of importing LNG at world prices into New England has changed, at least with respect to year-long deliveries of LNG. As a result, the two LNG buoy facilities of Neptune appear to be at least temporarily shut down. Nevertheless, the existing infrastructure remains available, under appropriate commercial terms, to meet near-term reliability requirements.

In our winter peak base case analysis, we assume that excess pipeline capacity will be available for deliveries of gas to generators. In addition to that amount, we assume that only 20% of the 3.5 Bcf per day total LNG infrastructure is available, or 0.7 Bcf per day, an amount slightly less than the continuous deliverability of Everett. With adequate commercial arrangements, an amount greater than that which can be produced from Everett could serve natural gas-fired generators. As sensitivities, we examine how changes to the amount of LNG available to natural gas generators will affect reserve margins.

3.1.3 Peak Gas Demand

Peak gas demand from LDC customers was estimated at 3.2 Bcf based on actual pipeline flows reported on January 3, 2014, one of the coldest 5% of all days in the

²⁰ DownstreamToday.com “Maritimes & Northeast Receives Canaport LNG Shipment” (<http://www.downstreamtoday.com/News/ArticlePrint.aspx?aid=17135&AspxAutoDetectCookieSupport=1> accessed 8/14/14)

²¹ *Ibid.*

²² “DOMAC Facts & Figures” by Distrigas of Massachusetts (www.distrigas.com/ourcompanies/lngna-domac.shtml accessed 8/14/14)

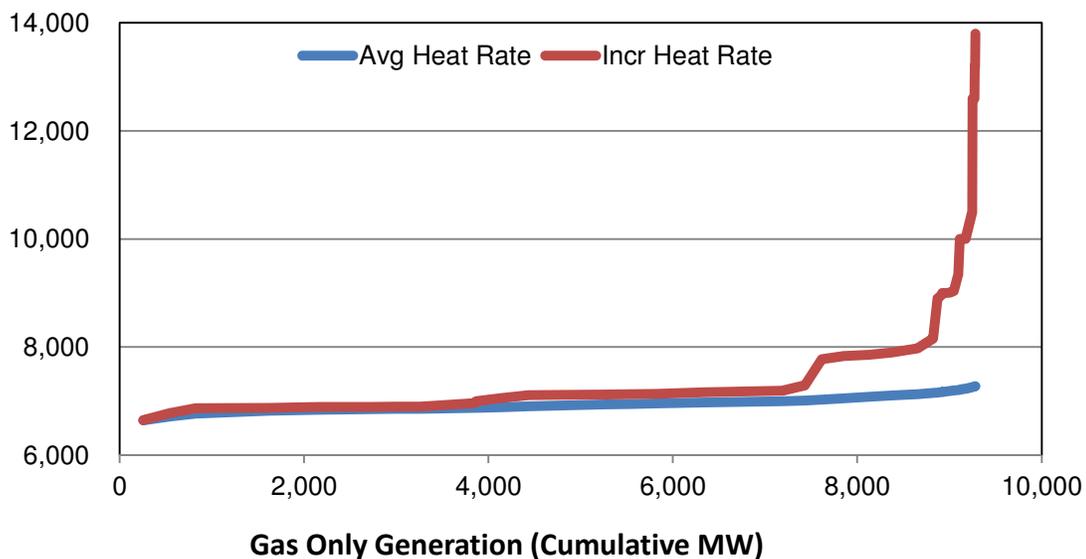
past 20 years.²³ This is increased at an annual rate of 1% per year based on EIA short-term natural gas consumption projections through 2015.²⁴

3.1.4 Gas Available for Generation

As discussed already, we assume a combination of excess pipeline capacity and the existing LNG infrastructure could be available to meet gas needs of generators over the study period. In winter 2014/15, this amounts to approximately 1.0 Bcf per day.

To translate the available gas per day into gas-fired generation available at the peak hour requires an assumption about the heat rate of the gas-fired fleet and total operating hours during the day. We conducted an analysis of New England's fleet of gas-fired generators which cannot burn oil. As shown in the figure below, although heat rates range from 6,600 Btu/kWh to more than 13,000 Btu/kWh, the bulk of the fleet as measured by capacity is below 8,000 Btu/kWh.

Figure 6: Average and Incremental Heat Rates – Gas Only Generation



Source: Energyzt analysis of Ventyx Energy Velocity Suite

If the fleet is fully dispatched, the average heat rate is approximately 7,200 Btu/kWh. For our winter peak base case we use a more conservative value of 8,000 Btu/kWh.²⁵

²³ Ventyx Energy Velocity Suite

²⁴ EIA, Table 5a. U.S. Natural Gas Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - August 2014, Released August 12, 2014, (<http://www.eia.gov/forecasts/steo/tables/pdf/5atab.pdf> accessed 8/18/14)

The operating profile of gas generators varies considerably, with peaking units running just a few hours a day and base load units at full load around the clock. Other gas generators will be in between and cycle up as demand increases. For the winter peak base case, we assumed an average profile of 16 hours to account for these differences and to more closely calibrate the gas generation for 2014 as reported in the FERC Data Request.

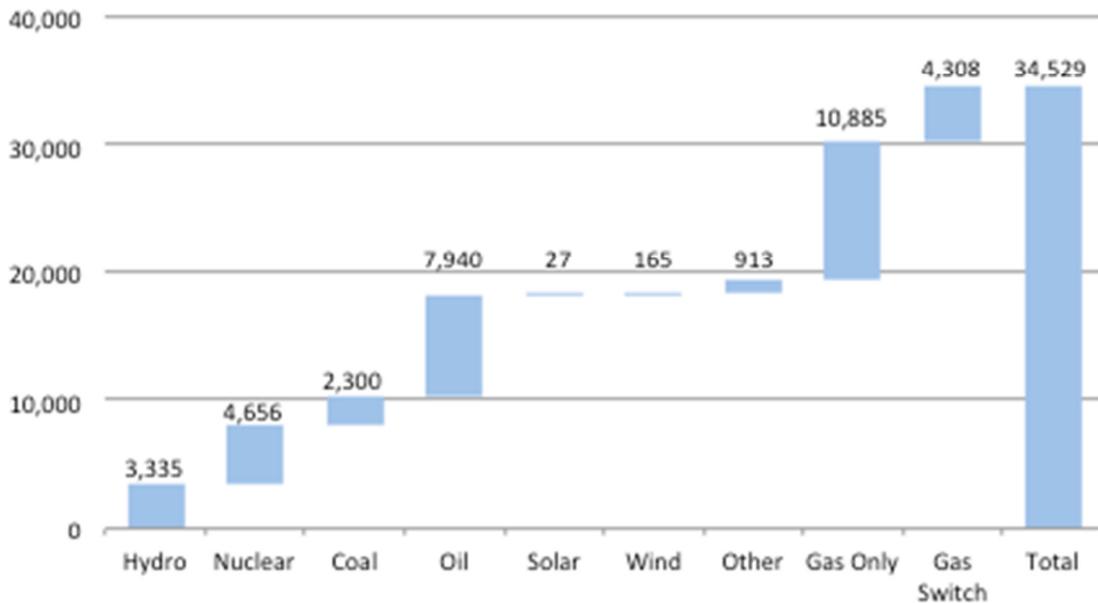
3.2 Generating Capacity

To estimate New England generating capacity available to serve winter peak demand, we adjust ISO New England's seasonal claimed capacity in 2014 for retirements, availability, and fuel limits.

3.2.1 Gross Generating Capacity

The following chart presents seasonal claimed capacity as used in ISO New England reliability calculations.

Figure 7: Seasonal Claimed Capacity by Primary Fuel Type (MW)



Source: Energyzt analysis of ISO New England, CELT Report 2014

Moreover, we do not assume that any of the units listed in Figure 8 will enter into reliability must-run contracts with ISO New England. Such contracts would require the continued operation of the stations and increase capacity available to serve demand and reserves. Although must-run contracts are a commercial arrangement that creates reliability options for ISO New England to use existing infrastructure, they are not included in this analysis.²⁷

3.2.4 Forced Outages

Generating units are subject to both planned and unplanned (or forced) outages. Given the heightened concern regarding winter peak reliability, we assume that no units will schedule planned maintenance on peak. The fleet will still suffer from random outages or reductions in capacity. Rather than simulate this on a unit-by-unit basis, we have assumed that all capacity is reduced by a factor of 5% in the winter peak base case based on historic performance of the New England fleet.²⁸

3.2.5 Derate Factors for Intermittent Resources

Renewable resources such as run-of-river hydro, solar and wind are able to provide energy on an intermittent basis; that is, when the renewable power source is available. Consequently, these resources do not provide the full capacity benefit for reliable operations as fossil or nuclear generators which dispatch on demand. As part of its capacity planning process, ISO New England reduces the amount of capacity available from these resources to meet peak demand via a methodology to estimate the so-called seasonal claimed capacity. Figure 9 shows the difference between total installed capacity as reported by Ventyx for hydro, solar, and wind and ISO New England’s reported seasonal claimed capacity used in this analysis.

Figure 9: Seasonal Claimed Capacity v. Net Winter Capacity (MW)

	Hydro	Solar	Wind
ISO-NE Seasonal Claimed Capacity	3,335	27	165
Ventyx Net Winter Capacity	3,686	256	834
Ratio: ISO-NE/Ventyx	0.9x	0.1x	0.2x

Source: Energyzt analysis of ISO New England, Ventyx Energy Velocity Suite

²⁷ ISO New England, “Status of Non-Price Retirement Requests,” ISO New England(http://www.iso-ne.com/genrtion_resrcs/reports/sts_non_retrmnt_rqst/ index.html accessed 8/14/14)

²⁸ “Generating Availability Data System – What It Is, What It Can Do, And Why You Should Care” page 19 by NERC (http://www.nerc.com/files/GADS_Data_Presentation.pdf accessed 8/12/14)

As shown in this table, hydro-electric seasonal claimed capacity is 10% lower than installed capacity. The difference for solar and wind is much higher, with ISO New England recognizing only 10% of solar capacity and 20% of wind installed in the region as seasonal claimed capacity.²⁹

We examined historic generation for hydro, solar, and wind generators during winter months to determine whether they should be further reduced from their seasonal claimed capacity to reflect their availability in the winter months. The following table summarizes the average and maximum daily capacity factors (compared to the seasonal claimed capacity) for these resource types for the months of January and February over the past seven years.³⁰

Figure 10: Historical Capacity Factors by Intermittent Resources

Year	Month	Average Capacity Factor			Max Capacity Factor		
		Hydro	Solar	Wind	Hydro	Solar	Wind
2008	1	34.8%	26.6%	26.0%	47.9%	60.8%	52.5%
2008	2	36.3%	6.5%	24.1%	42.5%	54.8%	57.8%
2009	1	30.4%	n/m	57.2%	37.0%	n/m	196.2%
2009	2	27.0%	n/m	129.4%	31.0%	n/m	237.9%
2010	1	33.2%	n/m	28.1%	42.1%	n/m	55.9%
2010	2	31.4%	n/m	35.7%	39.4%	n/m	76.3%
2011	1	28.4%	n/m	101.9%	37.2%	n/m	249.7%
2011	2	26.4%	n/m	139.8%	33.1%	n/m	250.7%
2012	1	31.7%	n/m	130.4%	39.0%	n/m	235.2%
2012	2	31.7%	n/m	130.4%	34.2%	n/m	277.8%
2013	1	29.0%	n/m	114.7%	39.7%	n/m	180.2%
2013	2	30.7%	n/m	111.2%	42.1%	n/m	200.7%
2014	1	34.0%	107.8%	172.2%	44.6%	278.7%	305.7%
2014	2	27.4%	138.6%	159.9%	33.2%	416.7%	292.0%
Average		30.9%	n/m	97.2%	38.8%	n/m	190.6%

Source: Energyzt analysis of ISO New England Daily Generation by Fuel Type³¹

Based on this analysis, it appears that hydro units on average generate energy equivalent to only a 30% seasonal claimed capacity factor during the months of January and February. Consequently, we determined that a reduction of 70% in the seasonal claimed capacity for hydro would be a conservative estimate for the reliability analysis.

²⁹ Ventyx Energy Velocity Suite and ISO New England, "CELT Report 2014 – 2023 Forecast Report of Capacity, Energy, Loads, and Transmission" 2.1 Generator List ISO New England

³⁰ Energyzt analysis of Ventyx Energy Velocity Suite

³¹ ISO New England, "Daily Generation by Fuel Type" (http://www.iso-ne.com/markets/hstdata/rpts/daily_gen_fuel_type/index.html) accessed 8/14/14)

This analysis is less conclusive for solar resources. However, given that winter peak hours tend to occur late in the afternoon, reflecting the heating and lighting needs of both residential and commercial customers, we assume that solar intensity will be too low for solar generators to contribute on peak winter hours. To be conservative, we apply a 100% derate factor, a conservative assumption as solar may be available to supply during peak periods in the winter.

Wind resources appear to have been able to generate, on average, at a 100% capacity factor of their seasonal claimed capacity. Maximum daily generation can be several multiples of the seasonal claimed capacity, reflecting the conservatism with which ISO New England treats wind in reliability calculations. For the purposes of this analysis, we do not derate wind beyond the seasonal claimed capacity in the winter peak base case. However, a derate is considered as a scenario in the sensitivity analyses.

3.2.6 Fuel Limits

As already described, gas fired generation which cannot switch to oil is limited to approximately 8,100 MW in the winter of 2014 / 2015 in the winter peak base case due to assumed gas availability. During January 7, 2014, only half of that capacity was dispatched due to forced outages and uncertainty over whether non-firm natural gas would be available (which subsequently was). For purposes of this analysis, the winter peak base case assumes the 8,000 MW is physically available if properly scheduled and contracted. Lower natural gas and power generator availability are tested as scenarios.

Oil fired units also may be subject to fuel limits related to storage and delivery constraints. These potential constraints are largely commercial, driven by the growing displacement of oil-fired generators due to the high price of fuel oil relative to natural gas, as opposed to a shortage of physical infrastructure. For the purposes of this analysis, we assume that oil-fired generation capacity is physically available with the only constraint being standard forced outage rates.³²

3.3 Imports of Power into New England

Transmission interconnections with Canada supporting long-term energy imports via DC tie lines have been an important supply resource for the ISO New England energy market balance. ISO New England also is interconnected to New York at

³² ISO-New England's existing Winter Reliability Program, which calls for 3.5 million barrels of on-site fuel storage, coupled with improved oil delivery logistics relative to this past winter, should mitigate the risk of commercially driven constraints on the peak availability of oil fired generators (both primary and secondary). "ISO-NE Filings Related with Winter 2013/2014 Reliability Solutions" ISO New England(www.iso-ne.com/key_projects/win_relbilty_sol/iso_ne_filings/ accessed 8/14/14)

several points via AC lines and across the Long Island Sound (the Cross Sound Cable) via DC lines. The net interchange with New York often results in imports into New England. As we have seen with operations on January 7, 2014, however, New England can be a significant exporter of power to New York, as well.

In addition, ISO New England cooperates with neighboring jurisdictions to engage in emergency purchases and sales when required to meet reliability requirements. In the days leading up to January 7, 2014, ISO New England was in ongoing communications and conference calls with surrounding transmission operators (i.e., NYISO, IESO, NBPSO, HQ, NPCC and PJM) to discuss conditions, expected forecasts and projected transfers. ISO New England rarely makes emergency purchases in the winter, but has sold emergency power to interconnected markets.³³

Actual power imports will depend on system conditions across the entire region, including the supply and demand balance in Quebec, New Brunswick, and New York (and beyond). Rather than simulate multi-market operations over this entire time period, for the purposes of this analysis we relied on the assumed interchange as used in the most recent ISO New England reliability study, the 2014 Capacity, Energy, Load, and Transmission (CELT) report. These net import values, along with the tie-line limits, are shown in the following table along with the flows that occurred on January 7, 2014 (negative flows represent exports). Details behind ISO New England's forecasted net imports are not provided in the CELT report, so only the total net imports are shown in Figure 11.³⁴

³³ ISO New England, <http://www.iso-ne.com/stlmnts/emerg/index.html>

³⁴ ISO New England, "CELT Report 2014 – 2023 Forecast Report of Capacity, Energy, Loads, and Transmission" 1.2 Winter Peak ISO New England

Figure 11: New England Transmission Interconnections and Imports (MW)

Control Area	Tie-Line Limits		Flows Jan 7, 2014	ISO-New England CELT Net Imports			
	Import	Export		2014 15	2015 16	2016 17	2017 18
Hydro Quebec							
Phase II	1,600	1,200					
High Gate	218	-					
Total	1,818	1,200	1,594	n/a	n/a	n/a	n/a
New Brunswick	800	200	638	n/a	n/a	n/a	n/a
New York ISO							
Roseton	1,400	1,200					
Northport	200	200					
Cross Sound Cable	346	330					
Total	1,946	1,730	(1,480)	n/a	n/a	n/a	n/a
Total	4,564	3,130	752	932	1,631	1,582	1,267

Source: ISO New England, 2014 CELT Report and FERC Data Request

For the winter peak base case results, we use the imports from the CELT report. As a sensitivity, we reduce imports to levels that occurred on January 7, 2014.

3.4 Peak Power Demand

Actual peak demand on January 7, 2014, was 21,432 MW. The table below shows winter peak demand forecasts by ISO New England representing the expected peak and two more conservative (i.e., colder weather) cases. The designation P50 refers to a probability of 50% that the actual demand will be less than the forecasted value; similarly P90 and P95 reflect a probability that actual demand will be less than the estimate 90 and 95% of the time.

These forecasts represent potential energy consumption before taking into account energy efficiency and other passive demand response that is built into the system. Therefore, in order to compare with the actual peak from January 2014, it is necessary to net out passive demand response. The ISO New England's projections of reserve margin in the CELT Report reflect a similar adjustment.³⁵

³⁵ ISO New England, "CELT Report 2014 – 2023 Forecast Report of Capacity, Energy, Loads, and Transmission" 1.2 Winter Peak and 1.6 Frct Distributions ISO New England

Figure 12: Winter Peak Power Demand (MW)

	Winter Peak Demand			
	2014 15	2015 16	2016 17	2017 18
P50	22,575	22,755	22,925	23,070
P90	23,325	23,505	23,670	23,815
P95	23,755	23,935	24,105	24,250
Passive Demand Response	(1,489)	(1,663)	(1,652)	(1,832)
P50 Less Passive DR	21,086	21,092	21,273	21,238
P90 Less Passive DR	21,836	21,842	22,018	21,983
P95 Less Passive DR	22,266	22,272	22,453	22,418

Source: Energyzt analysis of ISO New England, 2014 CELT Report

For the winter peak base case, we use the already conservative P95 case to reflect peak demand, even though (as seen last winter) it is unlikely to be coincident with peak natural gas demand days.

3.5 Summary of Winter Peak Base Case Assumptions

As noted above, a number of the assumptions that underlay the winter peak base case are purposefully set at more conservative values reflecting the potential situation that can arise on a winter peak day under extreme weather conditions. Figure 13 summarizes the underlying assumptions and the basis for each.

Figure 13: Summary of Winter Peak Base Case Assumptions

Parameter	Assumption	Source
Gas Market		
Pipeline	3.6 to 4.0 bcf/day	Existing capacity, AIM project; no Tennessee open season
LNG	0.7 bcf/day	Everett capacity only; No additional capacity from LDC peak shaving, Neptune, NE Gateway
Gas Demand	3.2 bcf/day	Based on January 3, 2014, demand escalated at 1% annually, source: Ventyx EV Suite
Power Market		
Non-Gas Capacity	24,000 MW	Seasonal claimed capacity, includes gas with switching capability; source: ISO-NE CELT
Gas-Fired Capacity	8,000 MW	Based on available gas, 8000 HR, 16 hour operating cycle; source: Ventyx, Energzt analysis
Retirements	1,400 to 4,000 MW	VT Yankee, Mt. Tom, Salem Harbor, Norwalk Harbor, Brayton Pt; source: ISO-NE CELT
Forced Outage	5.00%	Historical experience in ISO-NE; no scheduled maintenance on peak
Seasonal Derate of Renewables	Varies	70% derate for hydro, 100% for solar, 0% for wind; source: historic operations
Net Imports	900 to 1,600 MW	ISO-NE CELT Report
New Transmission	None	Ignores potential imports from transmission projects under development
Power Demand	~22,000 MW	P95 from ISO-NE CELT Report, adjusted for passive demand response
Oil Limits	Unlimited	ISO-NE Winter Reliability Program

4 ANALYSES AND RESULTS

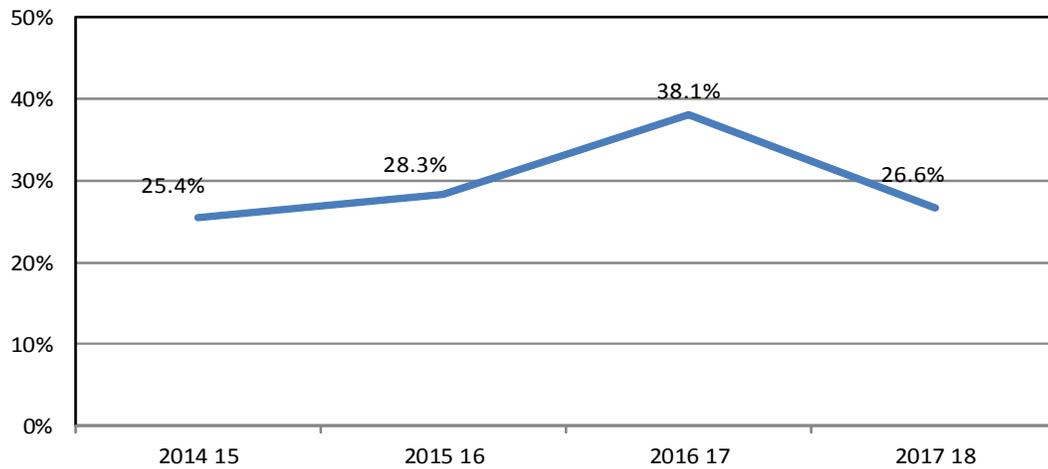
The assumptions developed in the prior section serve as the basis for estimating expected reserve margins in New England for the winter peak season in years 2014/15 through 2017/18.

This section reviews the results of the winter peak base case and compares them to the most recent ISO New England estimate for winter reserves. Next, we present a set of sensitivity analyses to identify how these results might change as the underlying assumptions change.

4.1 Expected Reserve Margins under Winter Peak Base Case

Assuming the winter peak base case assumptions described in section 3, expected reserve margins range from 25.4% to 38.1% over the next four winters, all of which are higher than the stated planning reserve margins of 15% (Figure 13). The significant increase in reserves observed in winter 2016 / 17 reflects the timing of the Algonquin Incremental Market project which will bring an additional 0.35 Bcf of gas per day into New England. This incremental gas capacity is sufficient to supply up to 2,700 MW of gas fired generation on peak. The dip in the final year of the study reflects the large number of generation retirements scheduled to occur.

Figure 14: Expected Reserve Margins under Winter Peak Base Case



Source: Energyzt analysis

The results of the winter peak base case analysis are significantly more conservative than the forecasts provided by ISO New England. In the 2014 CELT report, the ISO projects winter peak reserve margins of approximately 50% per year versus the analytical results that come in at sometimes only half of those levels (Figure 14).

Figure 15: Comparison of Base Case Results with ISO New England

	Winter Season			
	2014 15	2015 16	2016 17	2017 18
ISO New England CELT	49.8%	53.2%	50.0%	50.5%
Base Case Results	25.4%	28.3%	38.1%	26.6%
Ratio: CELT / Base Case	2.0x	1.9x	1.3x	1.9x

Source: Energyzt analysis, ISO New England CELT Report, 1.2 Winter Peak

Tighter margins under the base analysis reflect the extreme weather conditions built into the assumptions and serve as the foundation for showing how incremental events would affect reserve margins during winter peak conditions. In particular, we limit the amount of gas that is available for gas-fired generators to meet peak winter demand, derate renewables beyond their seasonal claimed capacity, and use a P95 case for power demand. In addition to assuming gas availability, capacity for renewables, and a P50 case for power demand, ISO New England’s analysis also includes approximately 1,000 MW of active demand resources that are not included in our base case. As such, the analytical results presented above reflect an extreme winter peak day, as opposed to an average winter day, and should be interpreted accordingly.

4.2 Sensitivity Analyses

As the past winter illustrated, it is not standard conditions that impact reliability, but a combination of events that have a compounding effect on energy availability and delivery. To reflect the potential impact of incremental issues during an already stressed winter peak day, we analyzed reserve margins that would result from changing the underlying parameters that serve as the winter peak base case assumptions. This allows a better understanding of the factors that drive outcomes and, consequently, which factors may be important drivers that ISO New England, policy makers and market participants can address to mitigate potential risk. The following table summarizes the sensitivities and reserve margin by year as key parameters are changed.

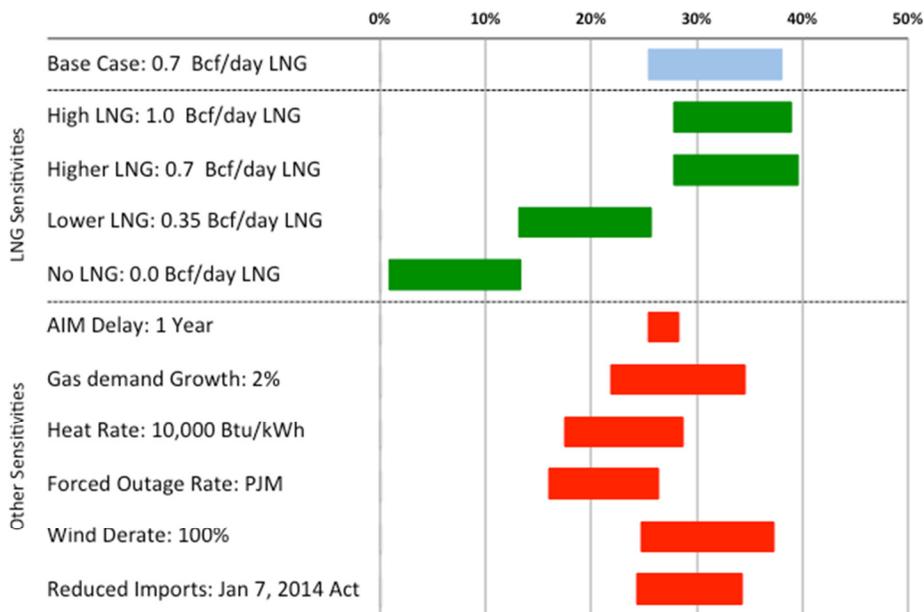
Figure 16: Sensitivity Analyses

Case	Reserve Margin			
	2014 15	2015 16	2016 17	2017 18
Base Case	25.4%	28.3%	38.1%	26.6%
LNG Sensitivities				
1.0 Bcf/day LNG	35.5%	39.0%	38.1%	27.8%
1.4 Bcf/day LNG	35.5%	39.6%	38.1%	27.8%
0.35 Bcf/day LNG	13.1%	16.0%	25.7%	14.2%
0.0 Bcf/day LNG	0.9%	3.6%	13.3%	1.7%
AIM Delay of 1 Year	25.4%	28.3%	25.7%	26.6%
Other Sensitivities				
Gas Growth: 2%	24.3%	26.0%	34.6%	21.9%
Heat Rate: 10,000	18.1%	21.2%	28.7%	17.4%
Forced Outage: PJM	16.0%	18.9%	26.3%	17.7%
Wind Derate: 100%	24.7%	27.6%	37.4%	25.9%
Imports: Jan 7 2014	24.6%	24.4%	34.3%	24.3%

Source: Energyzt analysis

Figure 16 presents this annual data graphically, showing the range of results across the four year study period.

Figure 17: Projected Reserve Margins 2014-2018 - Sensitivity Analyses



Source: Energyzt analysis

In all cases but for a reduction in LNG below the current deliverability of just the Everett facility, New England's existing infrastructure should be able to meet reasonable reserve targets. Even in the reduced LNG scenarios, however, delivery capability must be reduced by more than 50 percent before reserve margins are challenged. In the remainder of this section we provide details behind these sensitivity analyses.

4.2.1 LNG Sensitivity

The ability to use New England's existing LNG infrastructure is the most critical driver of expected reserves. In the base case, we only considered deliverability from the Everett facility. As an upside, we considered a case in which incremental deliverability up to 1 Bcf per day is implemented.

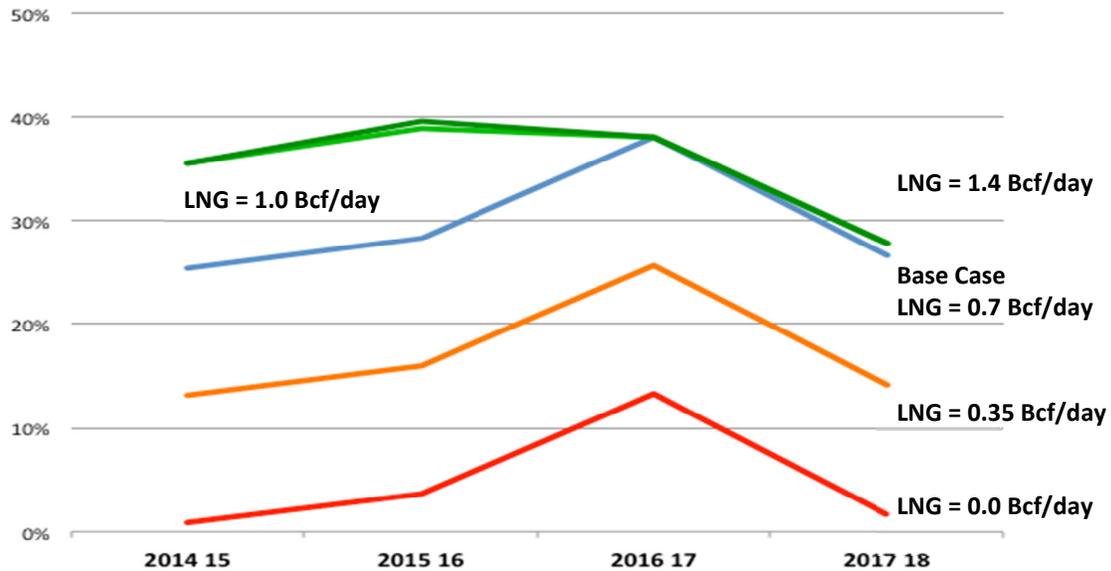
Additional LNG improves reserve margins during the first two winter seasons before incremental capacity from AIM is available, adding approximately 10 percentage points to reserves in 2014/15 and 2015/16. After AIM is on line, the gas fleet is nearly fully operational on peak, so there is little incremental improvement in going to 1.0 Bcf per day and no further improvement going to 1.4 Bcf per day. Nevertheless, additional deliverability is always helpful to system reliability, providing redundancy in the event of random outages.

A more important set of sensitivities to consider is a situation where less LNG than what is assumed to be provided by Everett is available to the system. The situation we represent here is not so much a question of infrastructure, since the assets are already in place, but the potential for outages or the lack of commercial arrangements to ensure the availability of LNG when it is needed during peak periods.

If LNG is reduced to 0.35 Bcf per day, or half the deliverability of Everett, reserves would fall to a range of 13.1% to 16%, with an increase in 2016/17 to 25.7% once AIM is on line. If no LNG was available -- that is, if gas were limited only to pipeline capacity in excess of LDC demand -- then reserves would fall to a range of 0.9% to 3.6% over the next two years, again with an increase in 2016/17 once AIM is on line to 13.3%. These are the only scenarios identified in which New England would not be able to meet its reliability obligations, and it highlights the importance of LNG as a risk mitigation tool to ensure reliability during New England winters.

The figure below compares the base case projections against the LNG sensitivities.

Figure 18: Reserve Margins - LNG Sensitivity Analysis



Source: Energyzt analysis

4.2.2 AIM Schedule Sensitivity

The Algonquin Incremental Market, or AIM project, is expected to provide approximately 0.35 Bcf per day of incremental natural gas into New England. This project includes upgrades of certain sections of pipes and added horsepower at multiple compressor stations. According to Algonquin, the project is expected to be fully operational in November 2016, thus available in our base case to serve winter peak in 2016/17.

As a downside, we considered the case in which AIM is delayed until the winter 2017/18. The results are unchanged compared to the base case with the exception of winter season 2016/17 when AIM was assumed to be available in the base case. Without AIM, the 2016/17 reserves are 25.7%, significantly higher than a reasonable target level of reserves.

4.2.3 Gas Demand Growth Sensitivity

There is limited public information about LDC firm demand growth across New England. In our base case analysis we used a growth rate of 1%, nearly twice as high as the growth in peak electric demand but consistent with EIA short-term projections for U.S. natural gas consumption. As a sensitivity, we considered a case in which gas demand growth was even higher, at 2% per year. As expected, higher

gas demand results in less excess pipeline capacity, lower availability of natural gas-fired units and, consequently, lower reserve margins. Compared to the base case, reserve margins in this case are between 22% and 35%, still in excess of reasonable reserve margin targets.

4.2.4 Heat Rate Sensitivity

In our base case we used a heat rate of 8,000 Btu/kWh to translate available gas into gas-fired generation. While the average efficiency of the fleet is below this value (i.e., more efficient), as a downside we considered a heat rate of 10,000 Btu/kWh, reducing the efficiency of the generators by 25%. Such a loss of efficiency would lower the amount of generation available on peak and lower reserves to 17%, still in excess of reserve margin targets.

4.2.5 Forced Outage Rate Sensitivity

Our base case analysis assumes random outages and reductions at generation facilities equal to 5% of seasonal claimed capacity based on historic experience of the New England fleet. This reduction in capacity is in addition to the derate we applied to renewable generation (hydro and solar) and the fuel availability constraint on gas-fired generation. Adding the forced outage rate, renewables derate, and fuel constraint on gas fired capacity, the total outage rate is 18.5% in the winter peak base case (i.e., only 72.5% of the non-retired capacity is available during the peak hour).

We considered a forced outage case based upon the experience of PJM this past winter during the Polar Vortex. During the period of January 6 through January 8, 2014, PJM experienced an uncharacteristically high level of forced outages across its fleet. Rather than previous winter peak periods with high forced outages approaching 10%, during the extremely cold days of January 2014, nearly 20% of the PJM fleet was unavailable.^{36 37} These outages included problems with frozen coal piles and difficulty starting units on alternate fuels.

New England has more operating experience with extreme cold than PJM as this past January indicates. Therefore, we would not consider the PJM experience to be directly applicable to New England. However, as an extreme downside case, we

³⁶ICF International, "Addendum to Polar Vortex Energy Pricing Implications – Commercial Opportunities and System Reliability," January 2014, (http://www.pserc.cornell.edu/empire/YAGTP4723_Addendum%20ICF%20Polar%20Vortex%20White%20Paper%2017Jan2014.pdf accessed 8/12/14)

³⁷ PJM, "Cold Weather Peaks and Generator Outages," January 9, 2014, (<http://www.pjm.com/%7E/media/documents/reports/20140109-january-2014-cold-weather-peaks-and-generator-outages.ashx> accessed 8/12/14)

applied the PJM data, which was available on a prime mover basis, to the New England fleet. The following table shows the forced outage rates on a primary fuel basis, as is used throughout this report. Because of the difference in resource mix, the generation weighted average forced outage rate for New England using the PJM experience this past winter is 12.8%, for an effective outage rate of 26.3% when combined with the assumed derates and fuel constraints in the winter peak base case.

Figure 19: PJM Forced Outage Rate Applied to New England Seasonal Capacity

Primary Fuel	New England Seasonal Claimed Capacity	PJM Forced Outage Rate by Primary Fuel
Hydro	3,335	1.0%
Nuclear	4,656	5.0%
Coal	2,300	20.4%
Oil	7,940	24.1%
Solar	27	56.8%
Wind	165	22.4%
Other	913	21.1%
Gas	15,193	10.1%
Total	34,529	12.8%

Source: Energyzt analysis of data from PJM, ICF International

Increasing the forced outage rate in New England to reflect the PJM forced outage rate experienced this past winter by generating fuel type, lowers the generation capacity available to meet demand and reserve margins. As a result, the expected reserve margins in this downside case fall to between 16.0% and 26.3%.

4.2.6 Renewable Derate Sensitivity

As discussed in Section 3.2.5, we derated hydroelectric and solar generation significantly below their seasonal claimed capacity to account for the possibility that there would be insufficient water or sun to operate at capacity on the winter peak. Wind was left unchanged from its seasonal claimed capacity of 126 MW in the base case, although this is an effective reduction of 85% based on New England's installed base of wind capacity of 833 MW.

We include a downside case in which wind is derated 100% to account for the fact that, despite geographic diversity and the reduction already applied to the seasonal claimed capacity, it might not be available on the peak winter hour. Losing this 126

MW has a marginal impact on reliability, reducing reserves by less than 1 percentage point per year.

4.2.7 Import Sensitivity

As a final sensitivity, we reduced imports from the winter peak base case assumption from ISO New England's projections in the 2014 CELT report to be equal to the actual net imports that occurred on peak on January 7, 2014. This sensitivity reflects a situation where neighboring regions are in a stressed condition due to the extreme winter weather and either unable to export into New England or, as occurred this past winter, in need of energy from New England. The effect of this sensitivity is to lower net imports from a range of 900 to 1,600 MW per year over the study period³⁸ to 752 MW in all years (recall that this included an emergency sale of 500 MW to PJM). This reduces reserves by up to 4 percentage points per year, still keeping them at a level that is well above a reasonable planning target. In sum, even under the stressed peak winter day represented by the base assumptions, New England is still able to provide emergency sales to neighboring markets, as it did this past winter, without jeopardizing its own reserve margins.

5 CONCLUSIONS

Actual experience from this past winter and analyses of scenarios on an already extreme winter peak base case indicate that New England has adequate energy infrastructure capability over the near term to meet its reliability requirements.

An extreme winter peak base case that limits the amount of gas availability, includes only firm energy imports, sets electricity demand at the high end, and reduces the contribution of renewables to capacity indicate estimated reserve margins ranging from 25.4% in winter 2014 / 15 to a high of 38.1% in winter 2016 / 17. Although lower than the ISO New England's estimates, projected reserve margins in each year are all significantly higher than a reasonable planning target of 15%, indicating adequate infrastructure.

On top of this already extreme winter peak day, we tested a number of compounding events to examine the sensitivity of the system during extreme weather conditions to an incremental risk factor. In nearly all cases, New England has sufficient energy infrastructure to meet electricity demand requirements and targeted reserve margins. The key factor that can create a reliability issue is if LNG from Everett is not available during extreme winter conditions. Otherwise, the

³⁸ ISO New England, "CELT Report 2014 – 2023 Forecast Report of Capacity, Energy, Loads, and Transmission" 1.2 Winter Peak

system is very robust and can meet an extreme combination of adverse conditions with the existing infrastructure.

Based on recent experience and the analyses described in this report, we conclude that there is no infrastructure gap, only a risk that planning is short-sighted, commercial arrangements are inadequate or government intervention is inappropriate. In such cases, the existing infrastructure will be constrained and may not be able to be optimized to address potential constraints. Otherwise, the system includes sufficient flexibility and asset capability to respond to extreme winter conditions.

Furthermore, there are a number of market-based solutions that have been announced and/or implemented that would further augment the existing infrastructure, offer additional flexibility, mitigate risks, and increase winter peak base case reserve margins. Adding these market-based solutions to the existing infrastructure only increases the ability of the system to respond to extreme conditions.

In summary, there does not appear to be an infrastructure gap in New England or lack of announced long-term infrastructure investment that would, in and of itself, preclude the ISO New England from maintaining reliability. Sufficient infrastructure already exists, if properly optimized through commercial arrangements to ensure reliability in the short term even under the most extreme conditions. Such commercial arrangements are more flexible than long-term infrastructure investment, provide more optionality to address key risk drivers, and can be more cost-effective than public intervention if properly managed in the interim while longer term private investment in infrastructure is implemented.

Lastly, it is important to recognize that the analysis described in this report focuses on the existing inventory of power and gas infrastructure in New England to determine the capability, not necessarily the economic implications or commercial realities, of meeting reliability requirements. . This past winter illustrated the benefits of proactive commercial arrangements, allowing the system to respond to extreme weather conditions while exporting 500 MW of emergency sales to PJM. That said, a variety of conditions, including but not limited to lower than normal reserve margins, contributed to higher prices for delivered commodity, prices that sent an important market signal to market participants regarding the need for longer-term investment. Short of an immediate deficiency in multiple aspects of the physical capability of a system, which for the most part can be addressed by the existing infrastructure, there is no identifiable market failure that precludes achievement of reliability targets.

As the analyses show, sufficient infrastructure exists in New England to meet target reserve margins under extreme winter peak conditions now and in the near term.

With adequate infrastructure, proactive planning and commercial arrangements can be used to optimize the system in the interim as private investment implements new infrastructure investment over the longer term.