Understanding ISO New England’s Operational Fuel Security Analysis

Prepared for: Conservation Law Foundation, Acadia Center, New Hampshire Office of the Consumer Advocate, PowerOptions, RENEW Northeast, Vermont Energy Investment Corporation

May 3, 2018

AUTHORS

Paul Peterson
Doug Hurley
Pat Knight

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

Synapse gratefully acknowledges funding from the Barr Foundation for the preparation of this report.

Table of Figures

HIGHLIGHTS

- ISO New England (ISO) did an in-house analysis of potential fuel risks for an extreme winter in 2024/25 that showed significant grid reliability issues and rolling blackouts under almost all scenarios studied.
- After stakeholders identified numerous problems with the assumptions ISO used for its model and scenarios, the ISO ran additional scenarios requested by stakeholders that showed fewer grid reliability issues and in many scenarios zero reliability concerns.
- Stakeholder scenarios based on a Business-As-Usual (BAU) set of assumptions showed no reliability issues at all related to fuel risks, even with the retirement of 5,400 MW of existing generation.
- The BAU scenarios assumed that current trends in electric and gas demand and LNG imports would continue and that states would achieve their existing policy goals in regard to renewables and electricity imports.
- Even in its original runs, the ISO finds that:
    - the reliability of the regional grid increases in direct proportion to the amount of renewable and clean resources added by state policies;
    - the addition of more cost-effective gas and electric energy efficiency measures increases system reliability; and
    - the reliability of the regional grid decreases as our reliance on gas-fired power plants increases.
- Reliable electricity service, with no rolling blackouts, is likely in an extreme 2024/25 winter without any increase in regional gas infrastructure if states continue to implement current policies.

EXECUTIVE SUMMARY

ISO New England ("ISO") released the first results of its Operational Fuel Security Analysis on January 17, 2018. The ISO analysis evaluated numerous scenarios using a model that represented an extreme winter for 2024/25. The model results showed significant reliability issues for most of the ISO scenarios, including many hours of load shedding that would produce rolling blackouts for New England consumers. For each scenario, the ISO assumed different resource mixes for the 90-day winter period including variations on electricity imports, LNG imports, oil supplies, renewables, and retirements of existing resources.

Regional stakeholders were not included in the development of the ISO's analysis or scenarios but provided the ISO with requests for additional scenarios for the ISO to model. Among those, a group of 14 New England Power Pool (NEPOOL) stakeholders submitted a joint request for a new Reference case called Business-As-Usual (BAU). The BAU scenario used more reasonable assumptions about future loads and resources than the ISO used in its Reference case. The ISO subsequently modeled the BAU scenario and the results showed no operational issues and no instances of rolling blackouts. In addition, many of the added risks that the ISO applied to their Reference case had minimal impacts when applied to the BAU case. Scenarios requested by other stakeholders also showed substantial reductions in risks during the winter of 2024/25 when compared to ISO scenarios.

Taken as a whole, the ISO scenarios and the stakeholder scenarios show a wide range of potential conditions during an extreme New England winter. The model results vary a great deal depending on the assumptions used in each scenario. When the ISO's arbitrary assumptions are replaced with current trends and existing state resource commitments, grid operations during an extreme winter are more manageable and no rolling blackouts occur. This report reviews how the key variables and underlying assumptions affect the likelihood of grid performance during an extreme winter in 2024/25. The following key takeaways are discussed in greater detail in the body of the report.

- For all of its scenarios, the ISO used unreasonable assumptions regarding consumer demand for electricity and natural gas for an extreme winter in 2024/25.
- For its Reference case, the ISO used unreasonable assumptions regarding three of the five fuel variables in its model:
    - For the renewable variable, the ISO did not give full credit to the renewable portfolio standards that have been adopted by all six New England states;
    - For the electricity imports variable, the ISO gave no credit for the Massachusetts legislation requiring 1,000 MW of clean energy;
    - For the LNG variable, the ISO chose a low value for daily contributions of LNG, when current LNG infrastructure can provide 50-100 percent higher amounts.

- Correcting the ISO’s unreasonable assumptions (BAU scenario) shows few operational issues and no reliability threats (reserve depletions or rolling blackouts) for an extreme winter in 2024/25.

- Stakeholder scenarios show numerous ways that operational and reliability concerns can be substantially reduced, if not entirely eliminated, when compared to the ISO’s scenarios.

- New England can achieve substantial improvements to the fuel security issues identified by the ISO without any new gas infrastructure (pipeline or LNG).

The ISO describes its analysis as an evaluation of fuel security risks. The ISO states that the most significant component of that fuel risk is the inadequacy of the natural gas delivery infrastructure. However, a close reading of all the ISO model results shows this need not be the case. Without any expansion of gas supply infrastructure, New England can dramatically reduce operational issues and improve reliability with current regional programs that add more renewables and electricity imports, combined with ensuring that LNG and fuel oil are delivered in a timely manner. The BAU scenarios show no fuel reliability concerns even with high levels of retirements.

The figure below compares the model results for the ISO Reference scenario and the stakeholder BAU scenario. It also compares the impacts of high levels of resource retirements on each scenario.

Figure 1. Reference and high retirement cases: ISO compared to stakeholder scenarios

						LNG capacity stressed	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric load shedding*	
Metric	**Ret cap**	**LNG cap**	**Dual -Fuel**	**Imports**	**RE cap**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
JR #1: BAU	-1,500	1.25	2	3,500	7,900	13	0	0	0	0	0
ISO 10: More retirements	–4,500	1.00	2	2,500	6,600	-	455	316	258	105	16
JR #15: BAU + Max Retirements	-5,400	1.25	2	3,500	7,900	13	0	0	0	0	0

Going forward, any changes in market designs or new programs intended to address the ISO's January study need to be developed with input from all stakeholders and take into account all the model runs requested. Relying solely on the ISO's worst-case scenarios could result in unnecessary costs for the region's electric ratepayers.

1. INTRODUCTION

On January 17, 2018, ISO New England ("ISO") released an initial draft of its Operational Fuel Security Analysis (OFSA Report).[1] The January draft evaluates many different scenarios for an extreme winter in 2024/25. Those scenarios assess the electric grid's reliability under an array of possible winter conditions. One of ISO's main findings is clear: If we simply meet the RPS standards already in place in the region, add the imports and offshore wind already required, use the extent of the existing liquified natural gas (LNG) infrastructure, and maintain backup oil, then the ISO can continue to operate a reliable system.

However, ISO has framed the findings from the January draft pessimistically by claiming its analysis shows that insufficient fuel for gas-fired power plants in winter months is a threat to reliability.[2] In its baseline "Reference case" the ISO projects that New England will face a future winter period during which electricity consumers will experience rolling blackouts. The Reference case uses estimated levels of electricity and gas demand and assumes specific levels of available supply from renewables, imports, and conventional resources for the winter of 2024/25. ISO also assumes, in all scenarios, that the winter of 2024/25 will bring record cold weather. In addition to the Reference case, ISO examined 22 other scenarios for the winter period, most of which show even longer periods of rolling blackouts.

But ISO's modeling in the January draft uses flawed and unreasonable assumptions, as pointed out by numerous stakeholders at a January 26 meeting and in written comments submitted on February 15. Synapse's earlier summary of the January ISO study details how the ISO's numerous overly conservative assumptions drove the initial OFSA results that showed extensive hours and days requiring emergency operations, scarcity pricing, depletion of ten-minute reserves, and rolling blackouts for an extremely cold winter in 2024/25.[3] Two of the most unreasonable assumptions were the devaluing of state renewable portfolio standard (RPS) goals and the failure to account for existing Massachusetts law that requires imports of clean energy.

Stakeholder comments submitted to ISO on February 15 included detailed assumptions to use in alternative scenarios. Nearly all of these new scenarios illustrate that by applying more realistic assumptions, New England will avoid all of the operational issues modeled by the ISO in its more dire scenarios. One of these new scenarios was a new "reference" case called Business as Usual (BAU). This

---

[1] ISO New England. 2018. *Operational Fuel-Security Analysis* (OFSA Report). Available at https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

[2] OFSA Report, January 17, 2018, at p.11.

[3] Knight, P., P. Peterson, D. Hurley, and J. Hall. 2018. *Working Toward a Clean, Reliable Electric Grid*. Factsheet prepared by Synapse Energy Economics prepared for Connecticut Fund for the Environment. Available at http://www.synapse-energy.com/sites/default/files/Working-Toward-a-Clean-Reliable-Electric-Grid.pdf.

new BAU case involved five major adjustments to the ISO Reference case to reflect a more realistic future. First, the estimated loads modeled for Winter 2024/25 were adjusted to reflect the values for winter energy and peak loads in the latest 2018 projection from the ISO.[4] Second, the estimated consumer demand for natural gas was adjusted downward to reflect trends over the last seven years. Third, the Renewables variable was increased to reflect actual, existing state RPS policies in New England. Fourth, the Massachusetts hydro legislation was assumed to be implemented. And fifth, the LNG peak day import level was set at 1.25 billion cubic feet per day (Bcf/day) to better reflect actual existing LNG import capability.

With those adjusted assumptions, all based on currently enacted policies and laws and existing infrastructure, the model showed no need for emergency operations or rolling blackouts for an extreme 2024/25 winter. Furthermore, when additional stress factors (increased fuel risks) were applied to the BAU case, the model continued to show a reliable system. When additional improvements (reduced fuel risks) were applied to the BAU case, system reliability was enhanced even further. This suggests that for the five variables that the ISO evaluated across all the scenarios (retirements, oil deliveries, imports, LNG, and renewables) the grid in 2024/25 during an extreme winter is likely to be more robust than the ISO's January OFSA suggested.

One significant risk factor that tended to skew results was the quantity of retirements of existing generation. As retirements increase to 4,000 or 5,000 MW of existing generation, the stress on the system is apparent in most scenarios other than BAU scenarios. Due to new ISO New England market changes, it is uncertain how quickly new resources might step in and compensate for some or all of the retiring resources.[5] In addition, there are existing rules and procedures around how resources retire and the ability of the ISO to retain some or all of those resources with performance contracts. This lack of certainty as to when a unit actually leaves the grid makes forecasts of retirements inherently speculative.

A separate aspect of the ISO fuel study involved singular disruptions the ISO modeled that are characterized as low probability but high impact events. These disruptions are not mitigated by adjusting the five fuel variables in the ISO's model. They include the three-month loss of both Millstone nuclear units, loss of the Canaport LNG import terminal in New Brunswick, loss of a gas pipeline compressor station, and loss of the Distrigas LNG terminal. Each hypothetical disruption creates a challenging winter scenario on its own. However, as discussed at the March 28 ISO New England Reliability Committee meeting, the ISO did not examine probabilities associated with any of these singular disruptions. The purpose of these scenarios is to emphasize the need to either lower the likelihood of these disruptions (such as improved security at compressor stations) or consider ways to directly mitigate the disruption should it occur (such as preparing plans to "pipe around" a compressor

[4] Each May, the ISO releases a projection of future energy consumption and peak demand known as the Capacity, Energy, Load, and Transmission (CELT) report. In 2018, the CELT report was released on April 30.

[5] These market changes include Pay for Performance and Competitive Auctions with Sponsored Policy Resources (CASPR).

station failure). Some stakeholder scenarios showed less disruptive impacts from these events by increasing gas supply and lowering consumer gas and electric demand.

In the rest of this report, we examine in more detail how the ISO set up its model, the assumptions that the ISO used, and the modeling results. Then, we review alternative assumptions and scenarios provided by stakeholders and how the model treated them. Finally, we make some observations about what the results from all of these model runs are showing us about future resource mixes and the risks associated with those mixes.

2. ISO Initial Analysis

In late 2016, ISO announced it would perform a fuel security study to evaluate risks to the reliability and resilience of the New England electric power grid.[6] The study used numerous scenarios to simulate the impact on operation of the electric grid during the 90-day winter season (December, January, and February). The ISO model assumed an extreme winter (similar to 2014/15) for the period December 2024 through February 2025 (Winter 2024/25).[7] The ISO assumed hourly winter loads based on the 2017 CELT report. The ISO model dispatched the system hourly over the 90-day winter period to determine daily energy consumption and peak loads and to identify any operational issues or system reliability events. The modeling effort had a specific focus on the availability of fuel to operate the system throughout the 90-day period.

2.1. Five fuel variables

The ISO examined five separate variables in its fuel security study, which it refers to as "risks." While one of these variables does represent a risk to reliability (higher levels of power plant retirements), the other four (renewables, imports, LNG, and oil refills) represent ways to *increase* system reliability. Note that there are other variables (including expanded electric or gas energy efficiency or targeted demand response) that could improve system reliability which the ISO did not test. The ISO varied quantities within each of these five variables to create distinct scenarios. It then compared all the model results from each scenario to a Reference case. For its Reference case, the ISO made the following assumptions about the five fuel variables.

[6] It is important to note that when the ISO announced its intention to conduct a fuel-security analysis in late 2016, stakeholders asked to be involved in selecting the scenarios to be evaluated. The ISO assured stakeholders that there would be an opportunity to review the ISO's study results before the results would be final. The ISO repeated those assurances throughout the 2017 study period. It was only after the ISO published its January draft of the OFSA that the ISO declared the study a final report and then submitted it to the Federal Energy Regulatory Commission (FERC) in March despite stakeholder objections.

[7] In most of its modeling work, ISO uses probabilistic assessments to describe future conditions. For the OFSA, the ISO used a deterministic assessment: only extreme winter conditions were used for 2024/25.

1) Renewables

The ISO used a value of 6,600 MW of renewable resources available in Winter 2024/25. Renewable resources are primarily wind, solar, and hydro; but they also include small amounts of biomass, fuel cells, and other technologies. This amount is substantially below the renewable requirements established by the six New England states in statutes and regulations; New England States Committee on Electricity (NESCOE) estimates the New England RPS goals at approximately 8,000 MW.[8] In two scenarios, the ISO used 8,000 MW of renewables as a high renewables assumption.

2) Imports

The ISO used a value of 2,500 MW of imports from neighboring control areas across existing transmission lines. These imports come mostly from New Brunswick and Quebec, with smaller contributions from New York.[9] The ISO ignored the 1,000 MW of peak capacity and associated energy authorized by the Massachusetts legislation and anticipated to be available by Winter 2022/23. The ISO believes that uncertainty about the construction of a transmission line to Canada disqualifies the additional imports for use in its Reference case. In other scenarios, the ISO varied imports from 2,000 to 3,500 MW.

3) LNG

The ISO used a value of 1.0 bcf/day for LNG import contributions from Distrigas, Canaport, and peak shaving facilities.

The ISO presented data that showed LNG imports could be as high as 1.5 bcf/day. For its Reference case, the ISO assumed 1.0 bcf/day. In other scenarios the ISO varied the daily delivery quantity from 0.75 to 1.25 bcf/day. Note that actual imports in February 2016 totaled 1.25 bcf/day.

4) Oil refills

Historically, and more so in recent years, dual-fuel generation units capable of switching from natural gas to oil have contributed significantly to grid stability during the winter season. Low oil prices over the last few years have made it more profitable for many dual-fuel units to burn oil rather than seasonally higher-priced natural gas.[10] If the region intends to rely on oil-fired generation during cold weather periods, the ISO wants assurances that oil tanks can and will be refilled during the winter season. The ISO's evaluation of available oil storage indicates a 10-day supply. A cold weather period longer than 10

---

[8] See NESCOE comments on OFSA, February 15, 2018. Available at: http://nescoe.com/resource-center/fsa-comment-feb2018/. RPS goals are expressed as quantities of energy (not capacity). Due to variations in capacity factors among different renewable resources, there are slightly different capacity totals that can satisfy the RPS energy requirements (based on the mix of resources chosen).

[9] Actual imports in 2016 are available at: https://www.iso-ne.com/static-assets/documents/2017/02/2017_energy_peak_by_source.xlsx.

[10] Oil market prices ranged from $35–55/barrel from 2013–2017. Over the last six months, spot oil prices have increased to $70/barrel.

days or numerous shorter cold weather periods in one winter would require refills of the oil storage tanks around New England.

For the Reference case, the ISO assumed that oil tanks would be filled twice during the winter, once at the start of the winter period and once during the winter, as signified by the number “2" under the graphic for this risk. In other cases, the ISO varied the number of oil tank fills from one to three.

5) Retirements

At the time of the study, the ISO had knowledge of scheduled retirements through May 2021, based on the results of its most recent forward capacity auction (FCA-11). The ISO is aware that other resources may be considering retirement.[11] Based on information known in 2017, the ISO used 1,500 MW to represent retirements for the Winter 2024/25 timeframe. In other scenarios, the ISO increased the retirements variable to as high as 5,400 MW.

2.2. Singular disruptions

In addition to the five variables that the ISO used in the modeled scenarios, the ISO also ran scenarios with singular disruptive events. These events were all high impact/ low probability failures of single large-infrastructure components for the entire winter period. They included a compressor station failure, the loss of the Canaport LNG terminal, the loss of the Millstone station (two nuclear units), and the loss of the Distrigas LNG storage facility. As might be expected, any one of these events puts the New England grid in a precarious situation. These single-event disruptions demonstrate vulnerabilities to the grid, but they are different from the five fuel risks that the ISO evaluated.[12] The potential “solutions” for these large-scale disruptions are also very different than the solutions for the five fuel risks. For instance, better security to thwart sabotage at compressor stations might be one approach to reduce the overall likelihood of a compressor station failure.

While it is helpful to identify the magnitude of single-event disruptions, it is also important to note that the ISO may not be able to meaningfully mitigate such risks. Also, these single event risks are not new concerns for Winter 2024/25; the grid is currently vulnerable to these risks and has been for several years. In this way, these single events are similar to an earthquake or other natural disaster that can severely disrupt electrical service over weeks or months. Stakeholders have implicitly acknowledged this and have not focused on alternative scenarios to solve for these single events. We agree that identifying

[11] This February, during the auction for the 2021/22 delivery year (FCA-12), three units at the Mystic generation station submitted dynamic de-list bids to remove themselves from the auction. ISO allowed one of the small units to de-list but retained the other Mystic units for local reliability needs (unrelated to winter fuel security issues). At the end of March, Exelon, the owner of the Mystic units, announced plans to retire all units (over 1600 MW) for the 2022/23 delivery year (FCA-13). We briefly discuss the uncertainties around the Exelon retirement request in Section 5 of this report.

[12] Exceptions to this general observation are the Environmental Defense Fund (EDF) scenarios that included the single event losses of Distrigas and Canaport. Some of the scenarios for each of these facilities show minimal load shedding. However, for these scenarios, EDF assumed new firm gas supply (pipeline or LNG) equal to 0.4 bcf/day. That addition of new gas supply effectively offset the loss of supply from Distrigas and Canaport. ISO New England presentation March 2018, slide 57.

and understanding the magnitude of these single-event risks is a useful exercise, but it is unlikely that the NEPOOL/ISO stakeholder process will be addressing these risks through market changes or the development of particular resources in the next few years.

2.3. ISO Reference case and variations

This section summarizes the findings from several of the ISO's modeled scenarios. In all scenarios, there are three critical inflection points on the right side of the ISO graphic under the Total Winter 2024/25 Impacts heading in Figure 2. The first is when LNG is being used at 95 percent of its maximum level, or cap. This is when the ISO starts dispatching oil units to conserve remaining gas supply. The second is when reserves are being depleted as part of actions under Operation Procedure 4 (capacity deficiency event). When ten-minute reserves are being depleted, the ISO declares a scarcity condition and significant penalties for non-performance can be levied against generators. The third inflection point is when Operating Procedure 7 (emergency event) is implemented. This is when load shedding procedures are started to avoid the collapse of the electric grid and consumers experience rolling blackouts.

Reference case scenario

The ISO Reference case shows 35 days when LNG will be at 95 percent of its cap level of 1.0 bcf/day and the ISO dispatches oil units to conserve remaining gas. Operational Procedure 4 (OP 4) actions will occur for a total of 165 hours and 10-minute reserve depletions will trigger scarcity pricing and generator penalties for 53 hours. The model indicates that Operating Procedure 7 (OP 7) actions to implement load shedding will be implemented for 14 hours (spread over six days). Under the ISO's flawed and unlikely assumptions, the Reference case outcomes show dire and unacceptable system conditions.

Figure 2. ISO Reference case, January presentation

					Description	*LNG capacity stressed*	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric load shedding*	
Metric	**Ret cap**	**LNG cap**	**Dual-Fuel**	**Imports**	**RE cap**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6

Variations on risks

The ISO developed many scenarios with different variations of risks. The chart below shows the model results for each scenario. The Reference case is in the middle, with less risky scenarios above it and more risky scenarios below it. All of the scenarios, other than the one ISO labeled the “High Boundary” case, show significant hours of OP 4 actions and the depletion of 10-minute reserves (market scarcity conditions). Most scenarios also show significant hours of OP 7. Note that ISO scenario 10 (Retire 4,500 MW) shows extensive disruptions to grid performance and over 100 hours of rolling blackouts.

Figure 3. Variations on risks

							LNG capacity stressed	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric load shedding*	
	Metric	**Ret cap**	**LNG cap**	**Dual-Fuel**	**Imports**	**RE cap**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
	Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
1	High Boundary	–1,500	1.25	3	3,500	8,000		0	0	0	0	0
2	More Renewables	–1,500	1.00	2	3,500	8,000		24	6	2	0	0
3	More LNG	–1,500	1.25	2	2,500	6,600		40	9	6	0	0
4	More Dual-Fuel Replenishment	–1,500	1.00	3	2,500	6,600		69	26	13	1	1
5	More Imports	–1,500	1.00	2	3,000	6,600		103	43	28	7	4
6	**Reference Case**	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
7	Less Imports	–1,500	1.00	2	2,000	6,600		239	120	87	33	7
8	Less Dual-Fuel Replenishment	–1,500	1.00	1	2,500	6,600		317	173	115	46	10
9	Less LNG	–1,500	0.75	2	2,500	6,600		355	208	153	58	10
10	More Retirements	–4,500	1.00	2	2,500	6,600		455	316	258	105	16
11	Low Boundary	–4,500	0.75	1	2,000	6,600		811	692	642	475	31

Combination of risks

The ISO combined several risk variations for some scenarios, such as increasing renewables and increasing retirements in the same scenario, as shown below. All scenarios have OP 4 actions and depletion of 10-minute reserves. Three of the four scenarios have hours of OP 7 actions, a.k.a. rolling blackouts.

Figure 4. Scenarios with combined risk factors

							LNG capacity stressed	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric load shedding*	
	Metric	**Ret cap**	**LNG cap**	**Dual -Fuel**	**Imports**	**RE cap**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
	Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
12	High RE/High Ret	–3,000	1.00	2	3,500	8,000		84	25	17	2	1
13	High LNG/High RE/High Ret	–4,000	1.25	2	3,500	8,000		18	4	2	0	0
14	Low LNG/High RE/High Ret	–4,000	0.75	2	3,500	8,000		358	200	154	56	12
15	Max RE/Max Ret	–5,400	1.00	2	3,500	9,500		206	94	64	15	6
6	**Reference Case**	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6

Single major-event scenarios

As mentioned earlier, the single-event scenarios represent the loss of major infrastructure for the entire winter period. Such losses are catastrophic events that cannot be effectively addressed by lowering any of the five fuel risk factors in the ISO Reference case. We present the scenarios below for purposes of information and completeness about what the ISO reviewed.

Figure 5. ISO New England's single major-event scenarios

							LNG capacity stressed	Electric capacity deficiency events		Reserve deficiencies	Emergency electric load shedding	
	Metric	**Ret cap**	**LNG cap**	**Dual -Fuel**	**Imports**	**RE cap**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
	Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
16	Distrigas LNG Outage: Ref	–1,500	1.00	3	2,500	6,600		276	114	87	24	7
17	Distrigas LNG Outage: Max	–5,400	1.00	3	3,500	9,500		346	181	142	49	11
18	Canaport LNG Outage: Ref	–1,500	0.65	3	2,500	6,600		270	129	90	27	9
19	Canaport LNG Outage: Max	–5,400	0.65	3	3,500	9,500		354	187	134	46	11
20	Millstone LNG Outage: Ref	–1,500	1.00	3	2,500	6,600		349	166	124	47	10
21	Millstone LNG Outage: Max	–5,400	1.00	3	3,500	9,500		389	243	193	70	12
22	Compressor LNG Outage: Ref	–1,500	1.50	3	2,500	6,600		458	290	252	138	17
23	Compressor LNG Outage: Max	–5,400	1.50	3	3,500	9,500		510	340	273	121	19
6	**Reference Case**	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6

2.4. ISO conclusions

The ISO identified six conclusions regarding the New England grid in its January report.[13]

1. The system is vulnerable to season-long outages of any one of several major, single events.

This conclusion about single events has not been disputed by stakeholders, nor have additional scenarios been modeled by the ISO. As described above, these high-impact but low-probability events are by their very nature categorically different than the five fuel variables the ISO modeled.

2. Reliable operation is dependent on LNG and electricity imports, as well as dual-fuel units.

This conclusion regarding the region's dependence on LNG, electricity imports, and dual-fuel units is also undisputed; however, increases in any of these three fuel resources can lessen the need for each of the

[13] ISO New England presentation January 2018, slide 13.

other fuel resources. For instance, greater imports of LNG can lessen the need for dual-fuel units, although the substitution may not be one-for-one.

3. Timely delivery of fuel (oil, LNG, and natural gas) is critical.

This conclusion regarding timely delivery of fuels is also undisputed by stakeholders; it also probably applies to any electric system that relies on fossil fuels. However, this concern may be mitigated by improved contracting arrangements that can provide these fuels on short notice.

4. All but four of 23 ISO scenarios include load-shedding in an extreme winter.

This conclusion is merely an observation of the results from the scenarios modeled by the ISO for the January report. When stakeholder scenarios from the ISO's March presentation are included, the likelihood of load-shedding in an extreme winter decreases considerably and disappears altogether in numerous scenarios.

5. More renewables can reduce fuel-security risks, but may lead to more retirements, too.

This conclusion reflects the interdependence of some of the fuel risk assumptions. Specifically, it focuses on the reduced risks from more renewables while acknowledging those same renewables may lower energy prices to an extent that more retirements of non-economic resources occur.

6. More renewables, imports, and a secure LNG supply reduce risks under all scenarios studied.

This final conclusion is the “good news” story that is hidden by all the gloom and doom in the ISO January OFSA study. Renewables and electricity imports, together with secure supplies of LNG, show substantially reduced risks. What the ISO describes as “more” is simply the amount that we would already expect in Winter 2024/25. Moreover, New England states have taken steps to address the need for more renewables and electricity imports than are online today through their RPS programs. Several states have backed their programs with specific legislation and RFPs for additional renewable resources to be developed in New England or purchased from neighboring control areas. The stakeholder scenarios in the next section show how these resource additions, when included as assumptions in the model, entirely eliminate rolling blackouts and reserve deficiencies as well as substantially improve grid operations during an extreme winter.

3. Alternative Assumptions and Scenarios

At a stakeholder meeting on January 24, the ISO encountered many questions about the assumptions that it used in its study to establish the Reference case for Winter 2024/25. Stakeholders questioned:

- Why did the ISO assume that state renewable goals established by each New England state through RPS programs would not be achieved, especially given that costs for these resources are declining and the region has historically met its RPS targets?

- Why did the ISO not account for Massachusetts legislation requiring the state to import approximately 1,000 MW of clean energy in the Reference case, especially when this precise resource was the subject of recent capacity market rule changes deemed urgent and necessary by the ISO?

- Why did the ISO assume aggressive and unrealistic projections for increases in consumer demand for both electricity and natural gas for 2024/25?

- Why did the ISO represent such a low level of LNG imports (1.0 bcf/day), given that the import terminals have the capability to import 1.5 bcf/day?[14]

The ISO invited stakeholders to submit alternative scenarios using different assumptions for the ISO to run through its model. In response, stakeholders submitted hundreds of alternative assumptions for the ISO to analyze. The ISO ran dozens of additional scenarios to accommodate specific requests and also provided graphic representations of how variations of certain assumptions would affect its January results.

The ISO provided stakeholders with the results of the additional model runs and analysis in March. The results were discussed at a stakeholder meeting on March 28.

A group of stakeholders representing members of several NEPOOL sectors (Joint Requesters)[15] submitted a comprehensive set of variations to the ISO's assumptions. The group included a request to modify the ISO Reference case, or, alternatively, create a new reference case that (a) better represents existing laws and regulations and (b) more closely tracks current New England trends in electric and gas demand.

We begin this section with a close look at the Joint Requesters scenarios and then we review a few of the scenarios requested by other stakeholders.[16] All of these scenarios show substantially reduced risks: the Joint Requesters scenarios eliminated all of the rolling blackouts and reserve deficiencies shown in the ISO scenarios that varied the five fuel risks.

---

[14] One LNG importer, ENGIE, requested a scenario with LNG imports at 2.54 bcf/day, a level that ENGIE says it is capable of importing with today's infrastructure.

[15] Joint Requesters are Massachusetts Attorney General's Office, New Hampshire Office of the Consumer Advocate, RENEW Northeast, Conservation Law Foundation, Brookfield Renewable, The Cape Light Compact, Environmental Defense Fund, NextEra Energy Resources, Natural Resources Defense Council, PowerOptions, Inc., Acadia Center, Sierra Club, Union of Concerned Scientists, and Vermont Energy Investment Corporation.

[16] As stated earlier, this report is not a comprehensive review of all the ISO-modeled scenarios. We have selected scenarios (ISO and others) that highlight particular issues and provide a context for looking at all the modeled scenarios. We encourage readers to review the ISO presentations from January and March after reading this report to understand the full range of conditions and risks that the ISO modeled. The January presentation is available at https://www.iso-ne.com/static-assets/documents/2018/01/a02_operation_fuel_security_analysis_presentation.pdf. The March presentation is available at https://www.iso-ne.com/static-assets/documents/2018/04/a2_operational_fuel_security_presentation_march_2018_rev1.pdf.

3.1. Joint Requesters assumptions and scenarios

Despite the flawed and unreasonable assumptions identified by stakeholders, the ISO declined to make any changes to its Reference case. Instead the ISO modeled a new Joint Requesters case labeled "business-as-usual" (BAU). The ISO then modeled multiple variations on this BAU case, many of which paralleled the variations to the fuel risk factors that the ISO applied to its Reference case. The comparisons between the ISO scenarios and the Joint Requesters scenarios are striking. All of the Joint Requesters scenarios featured minimal operational issues, no reserve deficiencies, and no rolling blackouts.[17]

BAU case

For the BAU case, the Joint Requesters replaced some of the ISO assumptions to reflect current regulations, laws, policies, and recent trends in electric and gas demand. The BAU case assumes that each state meets its RPS goals, as they have done historically. It further assumes that Massachusetts contracts for 1,000 MW of renewable resources from an external control area (most likely Canada) as required by state legislation 83D.[18] The BAU case assumes that consumer gas demand from local gas distribution companies (LDCs) will increase annually at the recent historical rate of 0.7 percent, instead of the ISO's assumption of 1.26 percent annually.[19] The BAU assumes that 1.25 bcf/day of LNG can be imported, as demonstrated in February 2016. The BAU also uses the 2018 CELT load forecast, instead of the 2017 CELT forecast used for the ISO scenarios. The BAU adopts the ISO's Reference case assumption for retirements (1600 MW) and assumes the same number of oil tank fills (2) for the winter season.[20]

In contrast to the ISO Reference case, the BAU case shows no OP 4 or OP 7 events for an extreme winter in 2024/25. There is also a reduction in the number of days that LNG imports will be at 95 percent of the LNG cap; the 95 percent level is when the ISO expects to start dispatching oil units. These model results are consistent with the ISO conclusion that more renewables, more imports, and firm quantities of LNG reduce the risks to the grid.

The figure below shows the results of the Joint Requesters' BAU case and the ISO Reference case.

---

[17] ISO posted updated stakeholder scenarios on April 27 that corrected for some errors in the original March 28 presentation. The revised presentation is noted as revision 1 on the ISO website. These updated scenarios are also included in an addendum to the study, available at https://www.iso-ne.com/static-assets/documents/2018/04/addendum-to-iso-operational-fuel-security-analysis.pdf.

[18] MAcleanenergy.com. "Massachusetts Clean Energy." Accessed April 24, 2018 at: https://macleanenergy.com/83d/.

[19] Synapse calculated the weather-normalized growth in LDC gas demand from 2010–2017 EIA data and applied that annual growth rate (0.7 percent) going forward to Winter 2024/25. ISO relied on a 2016 vintage gas forecast from a private consultant that assumed significant new LDC gas demand at an annual rate of 1.26 percent. Note that this forecast was developed using projections from the LDCs themselves that were filed with the state (in some cases) up to five years ago. Available at: https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-ldc-demand-forecast-03-oct-2016.pdf.

[20] The value of "2" in the ISO's Oil Tank Fills column indicates that fuel tanks are full at the beginning of the winter season, and then refilled only once during the winter.

Figure 6. Joint Requesters BAU case compared to ISO Reference case

					Description	*LNG capacity stressed*	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric forced outages*	
Metric	**Retirements**	**LNG cap**	**Dual-Fuel**	**Imports**	**Renewables**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
JR #1: BAU	-1,500	1.25	2	3,500	7,900	13	0	0	0	0	0

BAU variations

When optimistic variations to the BAU case are applied, such as even more renewables beyond what is currently required, more energy efficiency, or higher LNG imports, the ISO model shows that risks during an extreme winter in 2024/25 are further reduced.

Figure 7. Accelerated renewables variation

					Description	*LNG capacity stressed*	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric forced outages*	
Metric	**Retirements**	**LNG cap**	**Dual-Fuel**	**Imports**	**Renewables**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
JR #1: BAU	-1,500	1.25	2	3,500	7,900	13	0	0	0	0	0
JR #4: BAU + Accelerated RE	-1,500	1.25	2	3,500	10,500	6	0	0	0	0	0

Figure 8. Increased electric energy efficiency

					Description	*LNG capacity stressed*	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric forced outages*	
Metric	**Retirements**	**LNG cap**	**Dual-Fuel**	**Imports**	**Renewables**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
JR #1: BAU	-1,500	1.25	2	3,500	7,900	13	0	0	0	0	0
JR #5: BAU + Inc Elec EE	-1,500	1.25	2	3,500	7,900	5	0	0	0	0	0

Figure 9. Increase LNG imports

					Description	*LNG capacity stressed*	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric forced outages*	
Metric	**Retirements**	**LNG cap**	**Dual-Fuel**	**Imports**	**Renewables**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
JR #1: BAU	-1,500	1.25	2	3,500	7,900	13	0	0	0	0	0
JR #12: BAU + More LNG	-1,500	1.50	2	3,500	7,900	5	0	0	0	0	0

When pessimistic variations to the BAU case are applied, such as lower imports from Canada or more retirements, the ISO model shows virtually no changes to the operational risks during an extreme winter in 2024/25 and still no OP 4 or OP 7 events.

Figure 10. Lower imports from Canada

					Description	*LNG capacity stressed*	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric forced outages*	
Metric	**Retirements**	**LNG cap**	**Dual-Fuel**	**Imports**	**Renewables**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
JR #1: BAU	-1,500	1.25	2	3,500	7,900	13	0	0	0	0	0
JR #14: BAU - Imports	-1,500	1.25	2	2,500	7,900	19	0	0	0	0	0

Figure 11. Increased retirements variation

					Description	*LNG capacity stressed*	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric forced outages*	
Metric	**Retirements**	**LNG cap**	**Dual-Fuel**	**Imports**	**Renewables**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
JR #1: BAU	-1,500	1.25	2	3,500	7,900	13	0	0	0	0	0
JR #15: BAU + Max Retirements	-5,400	1.25	2	3,500	7,900	13	0	0	0	0	0

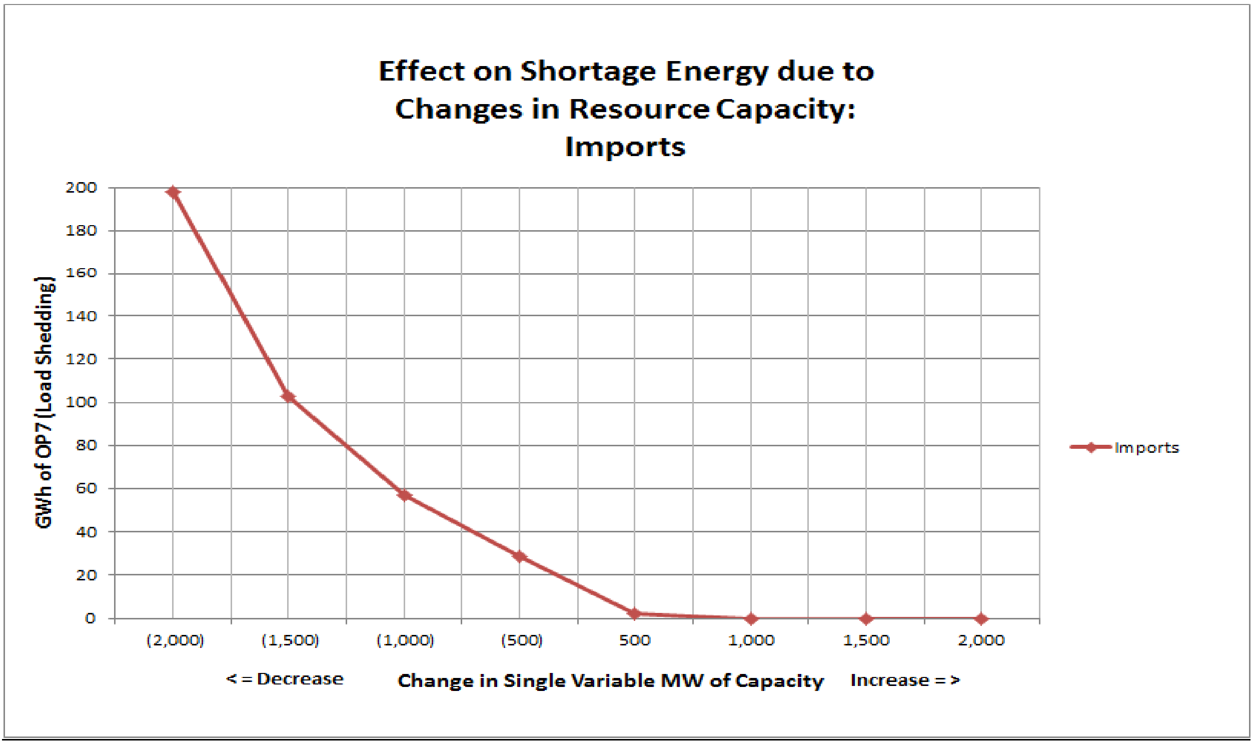
The results of the Joint Requesters scenarios shown in Figure 10 and Figure 11 are clear. Even if the new hydro power required by Massachusetts is not in service, or even if the region has more than 5,000 MW of retirements of existing generation units, the ISO can still operate the system reliably during Winter 2024/25.

3.2. Other stakeholder requests and scenarios

Other stakeholders submitted requests for additional scenarios. Some requested changes to single assumptions; some asked for combinations of different assumptions; and some requested low-medium –high variations to single assumptions. Overall, the ISO modeled dozens of additional scenarios. In addition, the ISO also quantified the impact on its analysis of adjusting single variables independently, as described next.

The ISO developed several graphs to represent a range of variations for a single variable. Variations to gas-fired generation capacity and PV capacity showed almost no impact on reliable operations. Variations to onshore wind capacity and offshore wind capacity both showed slight impacts. The most dramatic impacts were for variations to imports of electricity, variations to peak loads, and variations to LNG imports. Figure 12 and Figure 13 below show variations in single assumptions from the ISO Reference Case.

Figure 12. Variations to electricity imports (ISO March 2018, slide 25)



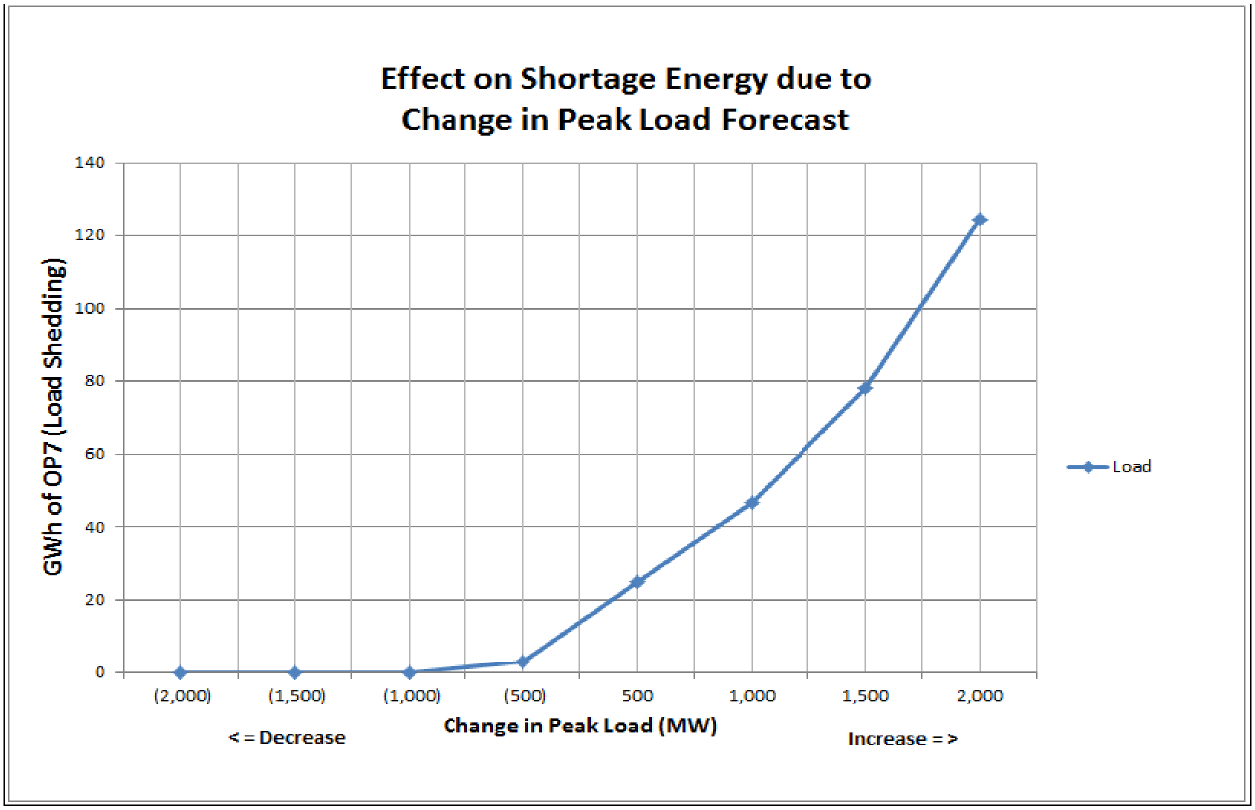
This graph shows that decreases to electricity imports increase the number of OP 7 hours for load shedding from the ISO Reference case value of 14 hours. It also shows that an increase in electricity imports of about 500 MW (half the quantity required under Massachusetts 83D legislation) can **reduce** the number of OP 7 hours of load shedding to zero. This is true even when using all other assumptions in the ISO Reference Case, many of which we find to be unrealistic (as described above).

The following graph shows that higher winter peak loads can increase the number of OP 7 hours for load shedding from the Reference case value of 14 hours. The graph also shows that lowering winter peak loads by about 700 MW can **reduce** the number of OP 7 hours of load shedding to zero. The recent trend of annual corrections to ISO New England peak load forecasts suggest that half of the 700 MW may come through forecast corrections alone.[21] The other 350 MW could come from very modest increases

[21] See *Updated Challenges for System Planning,* June 2017. Available at: http://www.synapse-energy.com/sites/default/files/Updated-Challenges-Electric-System-Planning-16-006.pdf.

to state-sponsored energy efficiency programs. Again, this chart is based upon the ISO Reference Case, which also assumes a growth rate in gas for heating demand that is nearly twice what it has been for the past decade.

Figure 13. Variations to peak loads (ISO March 2018 slide 26)



NESCOE scenarios

NESCOE requested many additional scenarios with different assumptions. For most scenarios, NESCOE included 8,000 MW of renewable generation to represent its estimate of the capacity (MW) necessary for states to meet their RPS energy (MWh) goals. Other variations looked at higher electricity imports and even more renewables to reflect current state laws, regulations, and state RFPs. Most of the NESCOE scenarios show substantially reduced risks during an extreme 2024/25 winter; many show no OP 4 or OP 7 events. The figure below shows several of the NESCOE scenarios requested and the model results. Other NESCOE scenarios are included in the ISO March 2018 presentation to stakeholders.

Figure 14. NESCO scenarios, ISO March 2018, slide 64

					Description	*LNG capacity stressed*	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric forced outages*	
Metric	**Ret cap**	**LNG cap**	**Dual-Fuel**	**Imports**	**RE cap**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
NESCOE More Imports w/Inc RE + Inc Imports	-1,500	1.00	2	3,500	8,000	29	24	6	2	0	0
NESCOE More Dual-Fuel w/Inc RE + Inc Imports	-1,500	1.00	3	3,500	8,000	29	8	1	1	0	0
NESCOE More LNG w/Inc RE + Inc Imports	-1,500	1.25	2	3,500	8,000	23	1	0	0	0	0
NESCOE Reference w/Inc RE + Inc Imports	-1,500	1.00	2	3,500	8,000	29	24	6	2	0	0
NESCOE More Ret w/Inc RE + Inc Imports	-4,500	1.00	2	3,500	8,000	29	186	81	62	13	5

Environmental Defense Fund scenarios

Environmental Defense Fund (EDF) asked for additional scenarios that varied many of the ISO assumptions about LDC demand growth, LNG imports, and some incremental increases in natural gas pipeline capacity. The model showed significant improvements to the ISO scenarios. Note that in most of the EDF scenarios there are still OP 4 and OP 7 events, although the hours of each are diminished. Figure 15 shows one slide showing model results of the EDF scenarios; the ISO March 2018 presentation has two additional EDF slides.

Figure 15. EDF scenarios, ISO March 2018 slide 54

					Description	*LNG capacity stressed*	*Electric capacity deficiency events*		*Reserve deficiencies*	*Emergency electric forced outages*	
Metric	**Retired cap**	**LNG cap**	**Dual-Fuel**	**Imports**	**RE cap**	LNG >95% Assumed Cap	All OP 4	Actions 6-11	10-Min Reserve Depletion	OP 7 Action: Load Shedding	
Unit	*MW*	*Bcf/Day*	*Oil Tank fills*	*MW*	*MW*	*Days*	*Hours*	*Hours*	*Hours*	*Hours*	*Days*
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
EDF More Ret 0.7% LDC Growth	-1,500	1.00	2	2,500	6,600	27	112	38	24	4	2
EDF Less LNG 0.7% LDC Growth	-1,500	0.75	2	2,500	6,600	35	91	33	21	2	2
EDF Less Dual-Fuel 0.7% LDC Growth	-1,500	1.00	1	2,500	6,600	27	78	23	17	2	1
EDF Less Imports 0.7% LDC Growth	-1,500	1.00	2	2,000	6,600	31	25	7	2	0	0
EDF Low Boundary 0.7% LDC Growth	-4,500	0.75	1	2,000	6,600	35	607	442	385	205	19
EDF Low LNG/HighRE/High Ret 0.7% LDC Growth	-4,000	0.75	2	3,500	8,000	23	71	18	12	2	1

Other Stakeholder scenarios

Numerous other stakeholders submitted requests to the ISO for scenarios and sensitivities to model. They include: Avangrid, BP Energy, ENGIE, Eversource, Iroquois, National Grid, and NRG.

We encourage those who want to understand the full range of possible conditions that were evaluated for Winter 2024/25 to review these additional model runs.[22]

4. Comparisons and Observations

4.1. Stakeholder scenarios improve reliability for a cold 2024/25 winter

All BAU scenarios show no reserve deficiencies or rolling blackouts when compared to ISO scenarios looking at similar fuel risks for an extremely cold winter in 2024/25. Many of the scenarios requested by other stakeholders that adjusted ISO assumptions also show reduced risks when compared to the ISO Reference case. Some of those scenarios eliminated all the negative operational impacts (the OP 4 and OP 7 events), while others reduced the number of such events.

[22] Available on the ISO website at: https://www.iso-ne.com/static-assets/documents/2018/04/addendum-to-iso-operational-fuel-security-analysis.pdf or https://www.iso-ne.com/static-assets/documents/2018/04/a2_operational_fuel_security_presentation_march_2018_rev1.pdf.

In contrast, all but four of the ISO scenarios show significant OP 4 and OP 7 events that will produce scarcity pricing, generator penalties, and rolling blackouts during an extreme winter in 2024/25 (including the ISO Reference case). Interestingly, the ISO High Boundary scenario that shows no such negative impacts is very similar to the Joint Requesters BAU case. The ISO describes its High Boundary case as a highly unlikely scenario.[23] The Joint Requesters describe their BAU case as the most likely scenario.

4.2. Stakeholder scenarios provide a more complete and realistic picture of the future

The ISO scenarios from the January presentations provided an ominous assessment for an extreme winter in 2024/25. The ISO headlined the OFSA as showing that New England was likely to experience rolling blackouts; a condition that the region has not experienced in 50 years. The ISO scenario results are not surprising based on unreasonable ISO assumptions about resource availability and increased consumer demand, as well as the single-event infrastructure failures that the ISO selected.

Stakeholder modifications to some of the ISO assumptions showed substantial reductions in risks and that the regional grid would be a more resilient grid during an extreme winter in 2024/25. Some of the modifications were grounded in current state requirements and recent data trends for both supply and demand. Some of the modifications were based on more optimistic assessments of future conditions such as LNG imports and tank refills for oil-capable units.

The stakeholder scenarios provide a more complete and balanced picture of current and future risks related to fuel security than the ISO scenarios alone. Conservative assumptions are the natural and expected orientation of a system operator with responsibility for the minute-by-minute delivery of electricity to all New England consumers under a range of weather conditions and infrastructure performance. But allowing worst-case scenarios to be the exclusive drivers of market design choices and resource policy decisions is never appropriate and would be unprecedented. The stakeholders' confidence in the ability of existing regulations, policies, and programs to achieve their goals deserve consideration as a means of balancing the extremely conservative assumptions used by ISO New England.

Taken all together, the different perspectives provided by stakeholders and the ISO allow regional policymakers to better understand the relative risks between different resource options and what combinations provide the ISO with the necessary tools to reliably operate the grid during extreme winter conditions in 2024/25.

[23] OFSA Report p. 37.

4.3. Retirements

One of the risks that proved difficult to address under most of the scenarios modeled was the High Retirements risk. Some of the scenarios showed that increasing retirements from 1,600 MW to 4,500 MW could be accommodated through increases in renewables, hydro imports, and LNG imports (as in the BAU cases and some of the NESCOE and EDF scenarios). However, the High Retirements variation (5,400 MW of retirement) showed likely OP 4 and OP 7 events in all scenarios, except for the BAU variation (JR #15). The ISO has experienced substantial retirements in recent years and expects that trend to continue. The timing of retirements, the quantity of capacity (MW) involved, and the location within the grid are all unknown and significant factors that affect grid reliability.

It is important to note that among all the risk factors and assumptions included in the ISO model, retirements are the one issue for which the ISO has key procedures already in place. For temporary retirements (one-year delist bids), the ISO must review the reliability impacts before the unit operator is allowed to delist its resource. For permanent retirements, the ISO does a reliability review to determine if the unit is needed. If it is, the unit operator is eligible for cost-of-service compensation for continued operation. We will learn over the coming months the options the ISO has for units that want to retire, presumably due to economic stress, and that may still be needed for traditional reliability concerns or the new winter fuel concerns identified in the ISO OFSA.

These procedures allow the ISO to mitigate the retirement variable in a way that it cannot with other risk factors. The ISO does not have the ability to install more renewables, import more LNG, contract for Canadian imports, or ensure that oil tanks are filled. Nor can the ISO reduce demand for electricity or natural gas. The ISO does have a major role in evaluating retirement requests.

5. NEXT STEPS

5.1. ISO stakeholder review

ISO originally planned to engage with stakeholders from May 2018 through June 2019 to discuss potential mitigation strategies for the fuel risks identified in the modeling of ISO and stakeholder scenarios. The ISO hoped to file market rule changes with the FERC in the first half of 2019 that could be effective prior to the FCM auction in February 2020 for the capacity delivery period of June 1, 2023, through May 31, 2024 (FCA-14). This is one year in advance of the 2024–25 winter period that the ISO used in its model.

However, Exelon has announced its intention to retire all units at the Mystic station (over 1600 MW) as part of the FCM auction in February 2019 (FCA-13) unless it can execute a two-year cost of service agreement to support continued operation of the Mystic units.[24] Even with a two-year agreement, the loss of Mystic station would equal all of the retirement amounts used in the ISO Reference Case for Winter 2024/25. Any additional retirements would push the region into those scenarios that show more retirements, and more severe reliability issues.

Since the Exelon announcement, the ISO has modified its plans as follows:

1. From April to June, the ISO will discuss with stakeholders a FERC filing the ISO will make to request a tariff waiver to allow the ISO to discuss a cost of service agreement with Exelon regarding the Mystic units. Under the current tariff language, there is no mechanism for the ISO to enter into a cost of service agreement based on winter fuel risks.[25]

2. After the ISO files its request for a tariff waiver, the ISO wants to discuss with stakeholders a tariff change that will allow the ISO to retain units needed for fuel risks through a cost of service agreement or some other mechanism without seeking a FERC waiver each time. The new mechanism would require a FERC filing and FERC approval for any resource owners that wanted to utilize the new mechanism. The ISO is anticipating that the Exelon retirement request may be followed by additional retirement requests. The ISO wants to file the request for a tariff change by November 2018.

3. Once the tariff changes are developed and filed, the ISO wants to shift attention to market rule changes that will make both the tariff waiver and the tariff mechanism unnecessary for future capacity commitment periods starting with FCA-15 in February 2021.

There may also be minor revisions to some of the stakeholder scenarios based on specific stakeholder requests. One of those requests is to incorporate the CELT forecasts for winter loads based on the 2018 CELT report published on April 30. An important consideration in developing market changes or procedures to mitigate future risks is to include stakeholder perspectives on the extent of those likely risks and not rely solely on the ISO January OFSA study.

---

[24] Recently, the owner of the Mystic units that operate mostly on LNG from the Distrigas facility in Everett, MA, has stated its intention to retire all the units and the Distrigas facility beginning with the June 2022–May 2023 power delivery year (FCA-13). The owners have stated a willingness to continue operation under a two-year cost of service agreement that must be approved by both ISO New England and the FERC.

[25] In the 1980s, cost of service agreements were made with resources that were needed for transmission reliability issue related to summer resource adequacy. Winter fuel issues are not a resource adequacy risk; the ISO is already compensating more resources than it needs in the winter months because some of those resources cannot access adequate fuel sources during extreme winter conditions

5.2. Other venues

A. FERC Resiliency docket

The FERC initiated a proceeding on the resiliency of electric grids (docket AD 18-7) in late December. ISO New England filed its comments on March 9, 2018, ands focused on the risks identified on the January OFSA study as the most pressing resiliency/reliability issue facing New England. The ISO has stated that it will not update its March 9 FERC filing to include the model results from the stakeholder scenarios. However, other interested parties to docket AD 18-7 have until May 9, 2018, to provide comments to the FERC. Those comments should certainly include some or all of the stakeholder scenarios and the results from the ISO model.

B. Mystic units

The process for determining the treatment of Exelon's Mystic units (and the associated Distrigas facility) may benefit from both the ISO and stakeholder OFSA scenario assumptions and model results. The ISO has already modified the model to reflect the ISO's assumptions about loads and resources available for the 2022-23 (FCA 13) time period. There may be opportunities to examine stakeholder assumptions with the modified ISO model for that same year.

C. Legislatures

There may be discussions at New England state legislatures about steps that can be taken to mitigate fuel risks in the near term without creating long-term commitments that may become uneconomic over time. The New England region is going through a transition from a largely fossil-fuel based resource mix to a renewable based resource mix as states try to address climate and energy needs in a comprehensive, least-cost approach. Both the ISO and stakeholder scenarios and model runs can help inform those discussions.