UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	))	Docket No. AD18-7-000

COMMENTS OF THE ATTORNEY GENERALS OF MASSACHUSETTS, RHODE ISLAND AND VERMONT

(May 9, 2018)

Pursuant to the Federal Energy Regulatory Commission's ("Commission") January 8, 2018, *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures* ("Grid Resilience Order"), the Attorneys General of Massachusetts, Rhode Island, and Vermont (hereafter "the Attorneys General") submit these comments in the referenced docket.[1]

On March 9, 2018, the Independent System Operator for New England ("ISO-NE") responded to the Commission's request for information on certain issues and concerns to further the Commission's examination of the so-called resilience[2] of the regional bulk power systems ("ISO-NE Response").[3] These comments address ISO-NE's Response, and in particular its Operational Fuel Security Analysis ("OFSA")[4] and provide the Commission with additional relevant data in the form of supplemental scenarios to the OFSA modelled by ISO-NE at the request of New England Power Pool ("NEPOOL") members and other regional stakeholders. While principally addressing ISO-NE's Response, we also reiterate our concerns with potential Commission actions in this docket or in the

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[1] *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC P 61,012 (2018) (hereinafter "Grid Resilience Order"). The Commission extended the deadline for comments by 30 days on March 20, 2018. *See Order Extending Time for Comments*, 162 FERC P 61,256 (2018).

[2] There is no consensus on the definition of "resilience." The term is not defined in the Federal Power Act or elsewhere in Commission documents. The Commission understands resilience to mean "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." *See* Grid Resilience Order, at 13. The Commission indicated that its definition is "[g]enerally based on the National Infrastructure Advisory Council's *Critical Infrastructure Resilience Final Report and Recommendation* at 8 (Sept. 8, 2009)," Grid Resilience Order, at FN 39.

[3] ISO-NE Response in "Grid Resilience Order" (March 2018).

[4] *Operational Fuel-Security Analysis,* ISO New England (January 2018) (hereinafter "OFSA"), *available at* https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

future that would result in ratepayer subsidies to uneconomic, inefficient resources on the flawed premise that they provide "resilience" benefits.[5]

As discussed further below, the Commission should not make recommendations nor draw conclusions related to the resilience of the New England bulk power system based solely or principally on ISO-NE's OFSA, as attached to ISO-NE's Response. First, the OFSA relies on underlying assumptions that do not present a realistic or complete view of either the present or the future bulk power system. Second, the OFSA presents a deterministic (as opposed to probabilistic) analysis that provides no context about whether modelled events are likely to occur. Third, the OFSA's approach to resiliency is too narrow. The concept of grid resilience encompasses considerations other than simply meeting load or even "fuel security."[6] Yet, the OFSA suggests that the ability to meet winter load with "secure" generator fuel supplies is equivalent to a "resilient" grid. The OFSA fails to consider the concept's broader meaning. For example, a resilient grid must also withstand events, such as cyber and physical adversarial threats, technological accidents, and extreme heat and other weather events, as well as other operational challenges including natural hazards, aging infrastructure, changes in capacity and demand, and skilled labor availability. Fourth, in contrast to the OFSA's seemingly dire conclusions, ISO-NE's recent supplemental modeling using up-to-date and corrected forecasting fundamentally changes the analysis and shows little risk to the resilience of the ISO-NE grid relative to fuel security.

Finally, issuance of the OFSA, as well as ISO-NE's supplemental modeling, is only a preliminary step in what should be a comprehensive stakeholder process to assist all New England stakeholders to identify and better understand any potential resilience risks and to arrive at a consensus as to necessary solutions, if any. Careful evaluation and common understanding of resiliency risks and

[5] *See* comments of State Commenters in RM18-1.
[6] The term "fuel security" is also a nebulous concept that lacks any accepted or legal definition.

solutions customized to the New England market, and that take into account all the facts, will avoid inappropriate, unnecessary, and costly market reforms and the risk of committing the region to unsuitable long-term strategies.

I. The Commission Should Not Rely Exclusively on the OFSA to Support Any Recommendations or Conclusions Regarding Grid Resiliency in New England.

a. *ISO-NE's Study Does Not Accurately Reflect the State of the Grid Today or What We Can Reasonably Expect to See in the Future*.

In its Response, ISO-NE states that "[i]n New England, the most significant resilience challenge is fuel security."[7] The Attorneys General recognize, like ISO-NE, that ensuring reliability, including the fuel security necessary to achieve that objective, is of great importance to New England's bulk power system. However, ISO-NE's framing of the problem represents a view that is inconsistent with the Attorneys General state clean energy policies and mandates and is neither representative of the world today, nor one that we can reasonably expect to see in the future.

The OFSA modelled 23 scenarios that represent a wide range of resource combinations that ISO-NE thought might be possible by winter 2024/2025. Five key fuel variables were considered: the retirements of coal- and oil-fueled generators; the availability of liquefied natural gas ("LNG"); dual-fuel generators' oil tank inventories; electricity imports; and the addition of renewable resources.[8] The OFSA also included projected energy efficiency ("EE") measures and distributed solar power as demand-reducing effects.

To contextualize the 23 scenarios ISO-NE created a "Reference Case," which is meant to be a "point of orientation for all the other scenarios"[9] and "a baseline scenario that represents a future resource mix, including low retirements and moderate levels of other variables, based on reasonable expectations that such levels will develop if the power system's evolution continues on its current

[7] ISO-NE, *supra* note 3, at 1.
[8] ISO-NE, *supra* note 4, at 11.
[9] *Id.* at 34.

path."[10] The Reference Case included these important assumptions: 1,500 megawatts ("MW") of generation retirements, one billion cubic feet per day ("Bcf/d") of LNG, two dual-fuel oil tank fills, 2,500 MW of imports, and 6,600 MW of renewables.[11]

Because the Reference Case was designed to "serve as a baseline for comparison with other scenarios,"[12] it is vitally important that it accurately reflect "likely levels" of system variables. However, ISO-NE admits that the Reference Case "does not incorporate state policy goals and requirements for clean energy."[13] The Reference Case also does not account for the 20 MW of battery storage currently connected to the regional grid, nor does it assume any amount in the future.[14] Instead, ISO-NE modelled state policy goals and requirements for clean energy in other secondary scenarios, including the "More Renewables" scenario, the "Max Renewables/Max Retirements" scenario, and the "High Boundary" scenario. Table 1 below identifies the variables used in these scenarios.

Table 1. ISO-NE variables for scenarios involving higher renewables.

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil tank refill)	Imports (MW)	Renewables (MW)
Reference Case	1,500	1	2	2,500	6,600
More Renewables	1,500	1	2	3,500	8,000
Max Renewables/Max Retirements	5,400	1	2	3,500	9,500
High Boundary	1,500	1.25	3	3,500	8,800

The OFSA also modelled eight outage cases to attempt to illustrate the effects of a winter-long outage at major energy facilities in the region and eight single-variable scenarios that increase or decrease the level of one key variable to assess its relative impact in each scenario.[15]

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[10] *Id.* at 33.
[11] *Id.* 33-36, 56.
[12] *Id.* at 8.
[13] *Id.* at 33.
[14] *Id.* at 14, 54. ISO-NE explains that "[a]dvanced storage technologies hold promise as resources that can support reliability … but cost-effective, advanced energy storage is not yet available at a scale that can ensure reliability on a 35,000 MW power system."
[15] *Id.* at 8, 56.

The results of each scenario were measured in the number of hours of emergency operating procedures that would be required to maintain system reliability when not enough fuel was available to generate all the electricity needed to meet forecasted electricity demand.[16] The OFSA found 19 scenarios where load shedding would occur, 22 scenarios where ISO-NE would have to make public requests for energy conservation, and only a single scenario without emergency actions.[17]

These results, however, are based on a series of erroneous assumptions that render the results unreliable. Specifically, the OFSA does not account for *existing* levels of interconnected renewable generation. For example, ISO-NE's base renewables assumption in the Reference Case is that the region will have 1,200 MW of onshore wind in 2024/25.[18] However, the 2017 Capacity, Energy, Loads and Transmission ("CELT") report shows 1,300 MW of onshore wind operating as of January 1, 2017.[19] Further, neither of the OFSA's "More Renewables" or "Max Renewables/Max Retirements" scenarios increase the level of onshore wind beyond 1,200 MW.[20] It is unreasonable to assume that there will be 100 fewer megawatts of installed onshore wind in New England in 2024/25 than there are today, and further, that no new onshore wind resources will be added. This assumption does not comport with any stakeholder's expectations of the future.

Even the Maximum Renewables/Maximum Retirements scenario, the scenario representing ISO-NE's prediction of the "maximum" amount of renewables and imports on the grid, has New

[16] *Id.* at 7-8, 29-31. Relevant emergency operating procedures include: Operating Procedure No. 4 ("OP 4") is used most often by ISO-NE to maintain supply and demand in balance, to avoid violating the 10-minute operating reserve requirement, and to avert the need to implement load shedding. OP 4 includes 11 actions. Most actions require no public notification or public response. *See* ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency* (July 5, 2017), *available at* *https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf*. If OP 4 actions are not sufficient, ISO-NE may start depleting 10-minute reserves. Once the 10-minute reserves are depleted, ISO-NE Operating Procedure No. 7 ("OP 7"), *Action in an Emergency*, is the emergency procedure that allows ISO-NE to implement load shedding. *See* ISO New England Operating Procedure No. 7, Action in an Emergency (January 17, 2017), *available at* https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op7/op7_rto_final.pdf.

[17] *Id.* at 8, 56.

[18] *Id.* at 26-27.

[19] ISO-NE. Capacity, Energy, Loads and Transmission Report (2017), at 2.1 "Generator List."

[20] *Id.* at 27.

England states just barely meeting their renewable portfolio standards ("RPS") requirements,[21] and not meeting the requirements under a 2016 Massachusetts law that calls for the equivalent of 1,200 MW of clean energy ("Section 83D") and 400 MW of offshore wind ("Section 83C") being added to the New England bulk power system by 2022,[22] Massachusetts' 2020 200 MW energy storage target,[23] as well as the intended results of ISO-NE's Competitive Auctions with State Policy Resources ("CASPR")[24] and Pay-for-Performance program.[25]

The Reference Case relies on several other flawed assumptions. For example, ISO-NE does not base its assumptions on *its own current forecasts*. The 2018 CELT number for electric EE is 4,318 MW, well above what the OFSA models.[26] The OFSA also models 4,432 MW of photovoltaics ("PV") while the 2018 Photovoltaic Forecast projects this number to be 5,072 MW in 2024.[27] Further, ISO-NE did not use its own 2018 draft load forecast which projects a significant decrease in load over the 2017 forecast that was used.[28] Although the 2018 forecast-based numbers were not available to ISO-NE when it ran the OFSA's scenarios; the OFSA was released just weeks before the new forecasts

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[21] *See* Massachusetts RPS, at https://www.mass.gov/renewable-energy-portfolio-standard; Connecticut RPS, *at* http://www.ct.gov/pura/cwp/view.asp?a=3354&q=415186; Rhode Island RPS, *at http://www.ripuc.org/utilityinfo/res.html;* New Hampshire RPS, *at* http://www.puc.state.nh.us/Sustainable%20Energy/Renewable_Portfolio_Standard_Program.htm; Vermont RPS, *at http://puc.vermont.gov/electric/renewable-energy-standard;* and Maine RPS, *at http://www.maine.gov/mpuc/electricity/RPSMain.htm.*
[22] Section 83D of Chapter 169 of the Acts of 2008 (the "Green Communities Act"), as amended by Chapter 188 of the Acts of 2016, *An Act to Promote Energy Diversity* (the "Energy Diversity Act").
[23] Letter from Judith Judson to Conference Committee Members, June 30, 2017, *available at* https://www.mass.gov/files/2017-07/letter-to-legislature-notice-of-energy-storage-target-adoption%206-30-17.pdf.
[24] Approved by the Commission on March 9, 2018, CASPR is a Forward Capacity Market ("FCM") reform where retiring resources that earn a Capacity Supply Obligation ("CSO") in the FCM could transfer the CSO to new, state-supported resources that do not have CSOs. The existing resource would retire and pay the state-supported resource for meeting the CSO. The price paid to the new resource would be determined by a second "substitution" auction. Several of the Joint Requesters opposed CASPR because of concerns that it will pose a barrier to incorporating renewables into the market and its phase out of the Renewable Technology Resource ("RTR") exemption, which allowed ISO-NE to clear 200 MW of renewable generation in the Forward Capacity Auction ("FCA") annually (up to 600 MW) without applying the minimum offer price rule ("MOPR"). Some Joint Requesters also opposed CASPR's lack of any backstop to ensure that renewables can enter the market if there are no fossil retirements to offset their entry.
[25] *See* https://www.iso-ne.com/participate/support/customer-readiness-outlook/fcm-pfp-project.
[26] ISO-NE. Capacity, Energy, Loads and Transmission Report (2018), at 1.2 "Winter Peak Capabilities and Load Forecast."
[27] *Id.* at 3.1.1 "Forecast of PV Resources by Category and State."
[28] Ethier, Robert. "Assessment of ICR/LSR and Discussion of the 2018 Long Term Load Forecast." Reliability Committee, NEPOOL (February 13, 2018), at 10.

were released. The effect of using 2017 numbers on ISO-NE's chosen scenarios is to increase the number of hours of emergency operating procedures the OFSA concludes would be required to maintain system reliability and the number of hours that customers would experience rolling blackouts.

The OFSA also assumes a high local distribution company ("LDC") gas demand growth of 1.26 percent annually based on an unconventional method used in a study conducted by ICF International.[29] The OFSA's use of this assumption results in an unnecessary increase in the region's expected use of natural gas. As a result, the region's fuel-delivery infrastructure is less likely to meet the demand and the numbers of hours of emergency operating procedures that otherwise would be required to maintain system reliability increases. There is insufficient evidence to support a near doubling of this growth rate, from 0.7 percent assumed by the Joint Requesters[30] (see below), to 1.26 percent as the OFSA assumes, in the coming years. Further, the OFSA assumed only 1 Bcf/d of LNG availability, whereas LNG operators have confirmed that they can flow twice that much.[31]

ISO-NE's use of these flawed assumptions biased its study in favor of finding significant risk, when in fact, once those assumptions are corrected, as explained below, that risk is drastically reduced. ISO's analysis, by design, leads to the conclusion that based on the region's current trends, market changes and other measures may be necessary to stave off threats to system reliability.

The Commission should not rely solely on the OFSA to inform its view of grid resilience in New England. Instead, when making any decisions, the Commission should also consider New England stakeholders' informed and reasonable assumptions—in many instances drawn from ISO's own most recent projections—about the future.

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[29] Petak, Kevin and Brock, Frank. "New England LDC Gas Demand Forecast Through 2030." Participants Advisory Council, ISO-NE (December 14, 2016), *available at* https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-ldc-demand-forecast-03-oct-2016.pdf.
[30] The 0.7 percent figure is drawn from the Energy Information Administration ("EIA"). Data for gas consumption by non-electric generation purposes since 2010 has a growth of 0.7 percent per year. *See* https://www.eia.gov/naturalgas/.
[31] *See* Engie comments on OFSA, pp. 3-4; *available at* https://www.iso-ne.com/event-details?eventId=135336.

b. *Additional Scenarios Run by ISO-NE at the Request of the Joint Requesters Show That Given Current Trends There is No More Reliability Concern in 2024/25 Than There is Today.*

As part of its stakeholder process, ISO-NE requested that stakeholders submit written comments on the OFSA, as well as any requests for additional scenario modelling. In response, the Joint Requesters[32] made several scenario requests based generally on the assumptions that New England states meet their RPS and greenhouse gas ("GHG") emissions requirements, and that legislatively mandated procurements of clean energy and energy storage occur as scheduled. (*See Appendix A*) The results of the Joint Requesters' scenarios demonstrate that relying on recent forecasts, including for renewables, imports, and LDC load growth, drastically reduces the number of hours of emergency operating procedures that would be required to maintain system reliability and would eliminate any incidence of rolling blackouts, when compared with the OFSA's results.

Although ISO-NE's Reference Case was designed to "serve as a baseline for comparison with other scenarios,"[33] many of ISO-NE's assumptions do not represent likely levels of system variables. In response, the Joint Requesters created their scenarios based on up-to-date variables that better represent what is more reasonably expected to occur in the future.

Specifically, the Joint Requesters requested that ISO-NE create a "Business as Usual" ("BAU") case that actually reflects likely levels of system variables that can "reasonably be expected to materialize in New England given current trends."[34] The Joint Requesters requested that nine variables be updated to reflect current or recently forecasted numbers. These variables are:

- A decrease in LDC gas demand growth from 1.26% per year to 0.7% per year. As mentioned above, an analysis of recent EIA gas data since 2010 shows an annual LDC gas use growth rate of approximately 0.7% annually;

[32] 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 Company, 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.
[33] ISO-NE, *supra* note 4, at 8.
[34] *Id.* at 22.

- An increase in electric EE impacts based on ISO-NE's draft 2018 forecast.[35] The draft 2018 EE forecast, using updated methodology, shows that energy demand reduction from passive EE increased substantially compared with the 2017 EE forecast: from 25,508 gigawatt hours ("GWh") in 2017 to 27,343 GWh in 2018;

- A decrease in gross load forecast based on ISO-NE's draft 2018 Long Term Load Forecast that shows the 2022 summer peak reduced by 2.1% compared with the 2017 forecast;[36]

- An increase in active demand response ("DR") to 500 MW. The twelfth Forward Capacity Auction ("FCA 12") concluded with 458 MW of existing active DR and 51 MW of new active DR;[37]

- A conservative increase in imports from outside New England of 1,000 MW from 2,500 MW to 3,500 MW based on the Section 83D upcoming procurement of 1,200 MW of generation;[38]

- An increase in the LNG cap from 1 Bcf/d to 1.25 Bcf/d which the LNG providers have shown they can flow;[39]

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[35] Table: Incremental Energy Savings from PDR in New England (GWh).

	CELT 2017 (final May 2017)	**CELT 2018 (draft Feb 2018)**
Through 2017	11,903	-
2018	1,376	(per 2017 CELT)
2019	1,632	2,690
2020	2,127	2,568
2021	2,403	2,498
2022	2,218	2,306
2023	2,024	2,104
2024	1,825	1,898
Total	**25,508**	**27,343**

[36] Ethier, *supra* note 28, at 10 (shows 2022 summer peak is reduced by 2.1% in draft 2018 forecast compared with 2017 forecast).

[37] While active DR historically shed much of its CSO following the FCA in the early years of the FCM, this does not appear to be the case in recent years. The February 2018 ISO-NE Chief Operating Officer ("COO") report shows that more recently the amount of CSO for active DR appears to be holding fairly steady. *See* Chadalavada, Vamsi. "NEPOOL Participants Committee Report." Participants Committee, NEPOOL (February 2, 2018), at 54-57.

[38] Section 83D solicits the procurement of resources able to deliver approximately 1,000 MW on average, whether from imports or another clean energy resource type, for delivery beginning by 2022. This process is well under way with the utilities intending to file a contract for approval imminently. Including this in the BAU case is consistent with ISO-NE's premise for requiring that CASPR be in place for FCA 13.

[39] *See* Engie comments on OFSA, pp. 3-4; *available at* https://www.iso-ne.com/event-details?eventId=135336.

- An increase in the amount of PV from 4,432 MW in ISO-NE's 2017 PV forecast to 4,990 MW based on ISO-NE's draft 2018 PV forecast;[40]

- An increase in the amount of onshore wind to assume 100 MW added by 2024 for a total of 1453 MW instead of 1200 MW;[41]

- An increase in the amount of offshore wind by 400 MW, from 30 MW, for a total of 430 MW based on the growth in RPS requirements and the ongoing MA 83C offshore wind solicitation, some of which should be in service by 2024/2025.[42]

When compared with ISO-NE's Reference Case in Table 2 below, the results of the BAU case shows that updating the nine variables zeros out the number of hours of any type of emergency action and eliminates the incidence of rolling blackouts.

Table 2. Comparison of ISO-NE's Reference Case and the Joint Requesters ("JR") BAU case.

	Retirements (MW)	LNG Cap (Bcf/d)	Oil Tank Fills	Imports (MW)	Renewables (MW)	Days of LNG at ≥ 95% of Assumed Cap	OP 4 Hrs.	OP 4 Action 6-11	Hrs. of 10 Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
ISO-NE 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	7,800	13	-	-	-	-	-

The Joint Requesters then requested that ISO-NE run 15 new single-variable and combination scenarios based on the BAU case. (*See Table 3 below*) These scenarios included requests to model battery storage, accelerate renewables deployment, a scenario in which ISO-NE's CASPR succeeds, increases in the number of dual-fuel replenishments, and increases in the number of retirements. All of these scenarios represent the energy future that New England stakeholders can reasonably expect to occur.

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[40] Black, Jon. "Draft 2018 Photovoltaic (PV) Forecast." Distributed Generation Forecast Working Group, ISO-NE (February 12, 2018), at 28-29, *available at* *https://www.iso-ne.com/static-assets/documents/2018/02/dgfwg_2018feb12_draft2018forecast_final.pdf*.

[41] ISO-NE, *supra* note 19 at 2.1. The 2017 CELT report shows 1,300 MW of onshore wind operating as of January 1, 2017. However, ISO-NE only modelled 1,200 MW. The ISO-NE interconnection queue shows that another 53 MW achieved a commercial operation date ("COD") in 2017. *See* https://irtt.iso-ne.com/reports/external.

[42] With these renewables assumptions, approximately 400 MW of new offshore wind is needed to meet the growth in RPS requirements between now and 2024/25. This is a reasonable, achievable projection given the ongoing MA 83C offshore wind solicitation. The Section 83C solicits the procurement of offshore wind to deliver 1,600 MW for delivery beginning by 2021/22. This process is well under way with the date for the selection of projects for negotiation set for May 23, 2018.

Table 3. Comparison of ISO-NE's Reference Case and renewables scenarios with the JR's scenarios.

Scenario	Retirements (MW)	LNG Cap (Bcf/d)	Oil Tank Fills	Imports (MW)	Renewables (MW)	Days of LNG at ≥ 95% of Assumed Cap[43]	OP 4 Hrs.	OP 4 Action 6-11	Hrs. of 10 Min. Reserve Depletion[44]	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
ISO-NE Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
ISO-NE More Renewables	-1,500	1	2	3,500	8,000	29	24	6	2	-	-
ISO-NE Max Renewables/Max Retirements	-5,400	1	2	3,500	9,500	23	206	94	54	15	6
ISO-NE High Boundary	-1,500	1.25	3	3,500	8,000	Unknown	-	-	-	-	-
JR #1 BAU[45]	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #2 BAU + Higher LDC	-1,500	1.25	2	3,500	7,800	23	-	-	-	-	-
JR #3 BAU + Thermal EE	-1,500	1.25	2	3,500	7,800	9	-	-	-	-	-
JR #4 BAU + Accelerated Renewables	-1,500	1.25	2	3,500	10,500	6	-	-	-	-	-
JR #5 BAU + Increased Electric EE	-1,500	1.25	2	3,500	7,800	5	-	-	-	-	-
JR #6 BAU + Battery Storage	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #7 BAU + Increased Security Combination	-1,500	1.5	3	3,500	10,500	7	-	-	-	-	-
JR #8 Accelerated Renewables + CASPR Success	-4,349	1.25	2	3,500	10,500	12	-	-	-	-	-
JR #9 BAU + Add'l Retirements	-4,349	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #10 BUA + Add'l Retirements + Add'l LNG	-4,349	1.5	2	3,500	7,800	4	-	-	-	-	-
JR #11 BAU + Compressor Outage + Counteracting Changes	-1,500	1.5	3	3,500	10,500	30	62	15	9	-	-
JR #12 BAU + More LNG	-1,500	1.5	2	3,500	7,800	4	-	-	-	-	-
JR #13 BAU + More Dual-Fuel Fills	-1,500	1.25	3	3,500	7,800	13	-	-	-	-	-
JR #14 BAU – Imports	-1,500	1.25	2	2,500	7,800	19	-	-	-	-	-
JR #15 BAU + Max Retirements	-5,400	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #16 BAU + Compressor Outage	-1,500	1.5	3	3,500	7,800	37	55	11	7	-	-

[43] This figure represents the number of days when at least 95% of the assumed maximum LNG injection in the scenario is being used. This number is significant because ISO-NE starts dispatching oil units to conserve remaining gas supply when LNG is being used at 95% of the assumed cap.
[44] If OP 4 actions are not sufficient, ISO-NE may start depleting 10-minute reserves.
[45] *See* Appendix A and Appendix B pp. 30-50 for a more detailed description of each scenario.

The modelling results in Table 3 rebut ISO-NE's prediction that, "maintaining reliability is likely to become more challenging," and refute the conclusions of the OFSA. These results demonstrate that using accurate renewables and other forecasts drastically decreases the need for ISO-NE to initiate emergency actions and eliminates the occurrence of rolling blackouts.[46] This is also the case for 14 of the 16 scenarios requested by the Joint Requesters. Even the two scenarios that result in emergency actions have fewer hours of such actions when compared with ISO-NE's similarly modelled scenarios. (*For an explanation of the comparison of the OFSA and the Joint Requesters' scenarios, please see Appendix C.*)

c. *The OFSA is of Limited Value to the Commission in This Docket Because It Does Not Assess the Likelihood of Resilience Risks.*

The Grid Resilience Order requests that RTOs and ISOs comment on the likelihood of resilience risks and characterize risks as low or high probability.[47] For example, the Commission's question number 2(b) asks "How do you assess the impact and likelihood of resilience risks?"[48] Question 2(c) asks ISO-NE to discuss the challenges it faces "[i]n trying to assess the impact and likelihood of high-impact, low frequency risks."[49] However, because the OFSA is a deterministic analysis and was not run for the purpose of responding to the Commission's grid resilience docket, it does not assess either the likelihood of the various

[46] In this regard, the results of ISO-NE's additional modelling affirm the conclusions of the Analysis Group's 2015 report, commissioned by the Massachusetts Attorney General, which confirmed that New England can maintain electric reliability through 2030 and that additional strategies like greater-than-planned deployment of EE, DR, and renewables can ensure reliability even in stressed system conditions. *See* Analysis Group, Inc., Power System Reliability in New England (Nov. 2015), *at* http://www.mass.gov/ago/docs/energy-utilities/reros-study-final.pdf.
[47] ISO-NE, *supra* note 3, at 13-14.
[48] FERC, *supra* note 1, at 13.
[49] *Id.* at 13-14.

modelled scenarios occurring, whether a modelled event constitutes a low or high probability, or the cost to customers of taking any particular action.

ISO-NE notes that "[n]either the reference case nor any of the other cases are predictors of the future."[50] In its response to the Commission, ISO-NE also explains that the OFSA "does not specify the probability of these cases."[51] However, offering the OFSA at all in response to questions 2(b) and 2(c) is misleading and confounds the difference between assessing the impact and the likelihood.

The failure to address the likelihood of occurrence of any of the scenarios is one of the OFSA's principal shortcomings that serves to diminish its value as a tool to facilitate the grid resilience discussion. Thus, the OFSA is of limited value to the Commission in assessing grid resilience in New England, and it is improper for ISO-NE to respond to questions about likelihood by citing the OFSA.

d. *The Concept of Grid Resilience Is Broader Than the Issue of Whether the System Can Meet Winter Load.*

ISO-NE's OFSA equates grid resilience with the system's ability to meet winter load by only evaluating whether the system is capable of meeting load in December, January, and February.[52] However, whether the system can meet winter load should be only one part of a comprehensive grid resilience assessment. A resilient grid must also withstand events, such as cyber and physical adversarial threats, technological accidents, and extreme heat and other weather events, as well as other operational challenges including natural hazards, aging infrastructure, changes in capacity and demand, and skilled labor availability. For example, the grid may face physical security risks which can "adversely impact the reliable operation of the

[50] ISO-NE, *supra* note 4, at 33.
[51] ISO-NE, *supra* note 3, at 39.
[52] ISO-NE, *supra* note 4, at 4.

Bulk-Power System, resulting in instability, uncontrolled separation, or cascading failures."[53] Weather-related events such as lightning and storms have been the biggest threat to energy infrastructure, historically. Weather patterns may affect the severity and frequency of natural disasters and adversely impact the operation of power plants and the reliability of grids.[54] Also, the Department of Homeland Security has found a growing potential gap in available skilled labor to replace the retiring workforce.[55] The loss of skills, experience, and knowledge poses a threat to the continuity of grid operations. Finally, inter-regional planning and critical infrastructure identification and protection are also grid resiliency concepts that must be addressed. Narrowing the meaning of grid resilience to winter peak conditions limits the OFSA's usefulness as a grid resilience assessment tool and places undue attention and concern on the single issue of winter reliability.

e. *The OFSA Demonstrates That Continued Deployment of Clean Energy Resources Will Improve Grid Reliability and Reduce Fuel Security Risks.*

Despite alarmist interpretations and rhetoric, and numerous flawed assumptions, the OFSA nevertheless shows that continued deployment of "[r]enewable resources can mitigate the region's fuel-security risk."[56] The High Boundary scenario, which best represents the 2024/25 New England energy outlook, includes more accurate levels of renewable energy generation,

[53] *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166, (2014), *available at* http://www.ferc.gov/CalendarFiles/20140307185442-RD14-6-000.pdf.
[54] Department of Homeland Security, Energy Sector-Specific Plan (2015), *available at* https://www.dhs.gov/sites/default/files/publications/nipp-ssp-energy-2015-508.pdf, at 16.
[55] Department of Homeland Security, Energy Sector-Specific Plan (2015), *available at* https://www.dhs.gov/sites/default/files/publications/nipp-ssp-energy-2015-508.pdf, at 18.
[56] ISO-NE, *supra* note 4, at 53.

LNG flow, level of imported energy, and an extra dual-fuel tank re-fill (during the coldest winters), results in zero hours of rolling blackouts and zero hours of emergency actions.[57]

This result is supported by the Joint Requesters' scenarios that show that a more realistic assessment of renewable penetration than that provided in the OFSA—using accurate forecasts and other data and assuming states will meet their legislatively-mandated clean energy goals—significantly decreases the need for ISO-NE to initiate emergency actions and eliminates the occurrence of rolling blackouts.

f. *ISO-NE's OFSA Narrative is Misleading and Inaccurately Characterizes the OFSA's Results.*

The Attorneys General acknowledge the importance of fuel security to the reliability of the New England bulk power system. The OFSA has some value in initiating discussions to identify what, if any, grid resilience challenges we face, followed by solution identification, if necessary. However, the Attorneys General are concerned with the narrative that ISO-NE is disseminating to the public, to legislators, and to regulators. Although the OFSA does not examine the probability of occurrence of any of the scenarios, ISO-NE's language in press releases, presentations and testimony before Congress is advancing a misleading narrative that the grid is in peril and customers are at risk of hundreds of hours of rolling blackouts. For example, in testimony before the Senate Committee on Energy and Natural Resources on January 23, 2018, ISO-NE's President and Chief Executive Officer, Gordon van Welie emphasized that the OFSA's "headline is that New England's limited fuel infrastructure *will* [emphasis added] eventually cause severe reliability issues if fuel security is not addressed."[58] In

[57] Ismay, David. *Study Proves Clean Energy Can Power New England's Future*, Conservational Law Foundation (March 7, 2018), *available at* https://www.clf.org/blog/study-proves-clean-energy-can-power-new-englands-future/.
[58] United States. Cong. Senate. Committee on Energy and Natural Resources. *Hearing on Performance of the Electric Power System Under Certain Weather Conditions*. Jan. 23, 2018. 115th Cong. 2nd sess. Washington: GPO,

ISO-NE's January 17, 2018 press release announcing the OFSA's release, ISO-NE states "The results indicate that maintaining reliability is *likely* [emphasis added] to become more challenging, especially if current power system trends continue."[59] However, the OFSA does not measure the likelihood of any of the scenarios occurring. Further, in a presentation to stakeholders on February 2, 2018, ISO-NE stated "[t]he OFSA models contain many hypothetical scenarios; none of which are precise predictions of the future."[60] Not only are the cases not precise predictions of the future, they are not predictions of the future at all.

At the urging of New England stakeholders, ISO-NE emphasized the deterministic nature of the OFSA several times throughout its response to the Commission.[61] Unfortunately, other language blurs the line between deterministic and probabilistic conclusions. For example, in discussing the study results ISO-NE speaks often in terms of "trends": "indicating the trends affecting New England's power system may intensify the region's fuel-security risk"[62] and "[c]urrent trends are pushing the power system toward greater risk."[63] Without using the words "likely" or "probably" ISO-NE is nonetheless indicating that the results of the OFSA show that the risk to the power system and fuel security are increasing. This narrative mischaracterizes the nature and results of the OFSA, which simply demonstrate that, should the future look like any of ISO-NE's hypothetical scenarios, then the grid would behave in a certain manner. It does not predict that any of the scenarios are more likely to materialize than any other.

2018 (statement of Gordon van Welie, President and Chief Executive Officer, ISO-NE); *available at* https://www.iso-ne.com/static-assets/documents/2018/01/testimony_gordonvanwelie_january232018.pdf.

[59] Press Release. ISO-NE, *ISO New England Publishes Operational Fuel-Security Analysis*, (January 17, 2018), *at* https://www.iso-ne.com/static-assets/documents/2018/01/20180117_pr_fuel-security_report_release.pdf.

[60] Chadalavada, Vamsi. "ISO New England's Response to Resilience Order." Participants Committee, NEPOOL (March 2, 2018), at 9, *available at https://www.iso-ne.com/static-assets/documents/2018/03/npc_20180302_composite.pdf*.

[61] ISO-NE, *supra* note 3, at 9, 28-30, 35, 39, 48.

[62] ISO-NE, *supra* note 4, at 5.

[63] *Id.* at 33.

Mischaracterizing the nature of the results mischaracterizes the nature of the risks that New England may actually be facing. Relying on this narrative may lead to unnecessary and costly infrastructure investments and to inappropriate, expensive, and burdensome regulation as well as unnecessary customer concern. For example, New Hampshire Public Radio published an article titled "Report: Current Fuel Trends Put New England At Risk For Rolling Blackouts."[64] Also, CommonWealth Magazine reported that "[a] new study … warns that without additional natural gas pipeline capacity … rolling blackouts are likely to become a reality."[65] Although, the Attorneys General do not expect ISO-NE to control how others interpret the OFSA, it is incumbent upon ISO-NE to present nuanced information in a careful manner that is least likely to be mischaracterized and to correct serious or public misinterpretations of the OFSA.

The Attorneys General ask that the Commission be mindful of the factual limitations and deterministic nature of the study during this proceeding.

g. *The OFSA Does Not Present the Full Picture of New England Grid Resiliency Because New England Stakeholders Were Excluded from the OFSA Process.*

In a departure from its typical stakeholder-oriented processes, ISO-NE purposefully excluded NEPOOL participants from every step of the two-year OFSA development process. All of ISO-NE's 23 scenarios were chosen without stakeholder input and reflect only ISO-NE's view of the relevant current and future characteristics of the regional bulk power system. Stakeholders repeatedly requested the opportunity to provide input on the scenarios, but ISO-NE refused all such requests. Only following the OFSA's public release were stakeholders invited to participate in a follow-on discussion. Part of the discussion included the opportunity to have

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[64] Annie Ropeik, *Report: Current Fuel Trends Put New England At Risk For Rolling Blackouts*, (2018), http://nepr.net/post/report-current-fuel-trends-put-new-england-risk-rolling-blackouts#stream/0.
[65] Bruce Mohl, *ISO Study Warns of Precarious Energy Future*, (January 17, 2018) https://commonwealthmagazine.org/energy/iso-study-warns-precarious-energy-future/.

additional scenarios run by ISO-NE, as discussed above, but the scenarios will not become part of the OFSA. Thus, while a number of alternative scenarios run at the request of NEPOOL members by ISO-NE are plainly more representative of future potential market conditions than those contained in the OFSA, ISO-NE has declined to include those results in the OFSA. Instead, ISO-NE has agreed to attach the presentation it gave in a NEPOOL meeting as an addendum to the OFSA.[66]

Due to the lack of stakeholder input and review, and the fact that the results of the alternative scenarios requested by NEPOOL participants are not incorporated into the report yet contain relevant and valuable data, the Commission should consider the OFSA to be a preliminary tool for the purpose of furthering stakeholder discussions only. The Commission should not rely on the OFSA to understand the present or future resiliency of the New England grid because it does not provide a comprehensive, realistic approach in its choice of modeling scenarios.

II. No Further Resilience-Related Commission Directive to ISO-NE is Necessary.

Because the stakeholder process was only recently initiated, the Attorneys General support ISO-NE's request to the Commission that the Commission wait to make any final decisions with regards to grid resiliency in the New England regional bulk power system until the stakeholder process has concluded. This process includes ISO-NE's near-term tariff-based approach for reliability review, a review of the proactive programs that the ISO-NE and stakeholders have developed together and implemented, such as Pay-For-Performance, as well as a broader discussion on resiliency and possible market-based changes. Also, because ISO-NE's

[66] "Operational Fuel Security Analysis: Stakeholder Requests for Additional Scenarios." Reliability Committee, NEPOOL. (March 28, 2018), *available at* https://www.iso-ne.com/static-assets/documents/2018/03/a2_operational_fuel_security_presentation_march_2018.pdf.

Response raises no immediate resilience concerns in the bulk power system, no further resilience-related Commission directive to ISO-NE is necessary at this time.

There is nothing in ISO-NE's submission to the Commission or the OFSA that substantiates the need for the Commission to give any directive to ISO-NE with regards to resilience. ISO-NE already operates the system in strict adherence to standards set by the North American Electric Reliability Corporation ("NERC"). This includes employing NERC-certified system operators, conducting operational readiness assessments, and developing operating procedures that incorporate NERC and Northeast Power Coordinating Council ("NPCC") standards.[67] ISO-NE also works with peer and industry organizations, and government, by coordinating with and participating in standard setting and information sharing.

ISO-NE and market participants are proactively building a resilient bulk power system to ensure continued reliability and resiliency through a number of initiatives. Much of ISO-NE's Response to the Commission outlines these initiatives. For example, ISO-NE explains that it "took major steps to increase efficiency and improve gas-electric coordination to address the challenges posed by the region's constrained natural gas-fuel infrastructure" in the ISO-NE markets.[68] These steps included day-ahead energy market timing changes "intended to give generators more time to procure natural gas by better aligning the electricity and natural gas markets timelines,"[69] and pay-for-performance rules, which "give resources incentives to undertake all cost-effective investments that enable them to perform when they are needed most."[70]

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[67] ISO-NE, *supra* note 3, at 18-19.
[68] *Id.* at 23.
[69] *Id.* at 23.
[70] *Id.* at 24.

On the operations side, ISO-NE describes how it developed "Operating Procedures, systems and tools to improve coordination, communications, intelligence and operations during cold weather conditions."[71] These include operating procedures "designed to improve information on generator availability during cold weather conditions"[72] and a "Gas Usage Tool [that] allows ISO-NE to estimate the amount of natural gas available for electric generation each operating day."[73]

Finally, New England continues to maintain system reliability in the winter, even under severe weather circumstances. During this time, our energy and capacity market prices have even been at historic lows.[74] Notwithstanding the OFSA (which as discussed above cannot at this time legitimately form the basis of any ISO-NE recommendations, market rule changes, or other Commission action), ISO-NE has not presented to the Commission or to stakeholders any evidence of resilience risks that require Commission action.

III. If Inadequacies in the Resilience of New England's Bulk Power System Are Identified, New England Should Be Permitted to Design New England-Specific Solutions Through its Stakeholder Process.

The Commission should provide regional flexibility to RTOs and ISOs to address regional resilience challenges, if any. As the Grid Resilience Order acknowledges, "(t)he Commission recognizes regional differences amongst the RTOs/ISOs, and appreciates that those differences impact how each RTO/ISO approaches resilience in its region."[75] In its recent order on energy storage ("Storage Order"), the Commission noted that "different RTOs/ISOs may be able to more effectively account for the physical and operational characteristics of electric

[71] *Id.* at 25.
[72] *Id.* at 25.
[73] *Id.* at 26.
[74] "Results of Annual Forward Capacity Auctions", 2008-2018, *available at* https://www.iso-ne.com/about/key-stats/markets#fcaresults.
[75] FERC, *supra* note 1, at 90.

storage resources through different mechanisms given their unique market designs."[76] The Commission's rationale in the Storage Order is applicable in the grid resiliency context given the vast difference in resilience concerns the regions may face as a result of differing operating environments, wholesale markets design, and state policy mandates.

Solutions to regional concerns should be regional in nature and developed through the NEPOOL stakeholder process. ISO-NE and regional stakeholders including, regulators, policymakers, and market participants, continue to successfully develop and design market rules specific to the unique characteristics of New England's power system. To date, the market's successful operation is largely a result of the open, transparent, and inclusive market design process through NEPOOL. Addressing resilience is a complex question requiring consideration of a much wider range of challenges and solutions than just fuel security.

Should the Commission identify inadequacies in the resilience of New England's bulk power system, the Commission should permit New England to develop specific solutions through its tested and proven stakeholder process. Any future Commission action in connection with the Grid Resilience Order, should allow for, respect, and incorporate the results of that process.

IV. The State Commenters Oppose PJM Interconnection's Proposal to Compel All RTOs/ISOs to Develop Plans to Compensate Uneconomic Resources for Resiliency.

The Attorneys General remain concerned that the Commission may be considering addressing resilience with blunter instruments than the consultative and targeted regional processes already underway at the nation's RTOs, including ISO-NE as described above. In this regard, we reiterate our opposition to Commission action to compel ratepayers to subsidize

[76] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,127 (2018) at 115-116. (Hereinafter "Storage Order").

uneconomic resource categories on the grounds that such resources are supposedly important to grid resilience, as reflected in comments filed by state attorneys general, ratepayer advocates, and state agencies in the Commission's docket regarding the Department of Energy's ("DOE") notice of proposed rulemaking regarding electric grid resilience.[77] In these comments we argued that DOE's proposal for a federal mandate to subsidize "fuel-secure" resources would significantly and unnecessarily raise energy costs for consumers, that it is unnecessary to support system reliability, and that it would prolong the life of coal-fired power plants which would exacerbate public health and environmental harms caused by such facilities. Such a proposal would also violate the Federal Power Act.

Although the Commission's order terminating that rulemaking rejected the DOE proposal for sweeping cost-of-service payments to certain resources, we continue to oppose similarly unnecessary measures that the Commission may be considering as part of this docket or otherwise. In this regard, we oppose any adoption of PJM's proposal to compel all RTOs and ISOs to develop plans to compensate uneconomic resources for resilience services on an expedited timeframe.[78] Beyond the impracticality of multiple simultaneous proceedings regarding tariff changes to improve resilience for Commission staff and affected stakeholders, there are fundamental fairness and due process implications of imposing such a burden and expense upon non-utility, non-RTO/ISO parties, particularly where the action is unwarranted.

[77] *See* Comments of State Commenters in FERC RM18-1, Grid Reliability and Resilience Pricing (October 2017).
[78] PJM Interconnection, L.L.C., Response in "Grid Resilience Order" (March 2018), at 6, 82. PJM requested that the Commission, "[r]equire that all RTOs (and jurisdictional transmission providers in non-RTO regions) submit a subsequent filing, including any necessary proposed tariff amendments, to implement resilience planning criteria, and develop processes for the identification of vulnerabilities, threat assessment and mitigation, restoration planning, and related process or procedures needed to advance resilience planning."

V. Conclusion

The Commission should not rely solely on the OFSA as a basis for findings of fact or orders for remedial action because it presents an incomplete, inaccurate, and therefore misleading view of the New England grid's characteristics and risks, and because it makes no attempt to assess the likelihood of occurrence of the various scenarios it modelled.

The OFSA's flawed factual assumptions and selective scenario modelling skew the results to show a future where the New England grid is more susceptible to fuel-security risks than it is when compared to stakeholder-requested scenarios. The Joint Requesters' scenarios present a more realistic view of the 2024/25 operating environment that also vastly decreases the occurrence of all types of emergency proceedings and eliminates rolling blackouts.

With sufficient time and opportunity, the current stakeholder process addressing near-term tariff-based approaches for reliability reviews, a review of the proactive programs that ISO-NE and stakeholders have developed together and implemented, as well as the broader discussion on resiliency and possible market-based changes, should bring into focus any actual future resilience concerns in a responsible and collaborative manner. Any proposed reforms made based on both the outcome of the stakeholder process and the Commission's investigation, must be based on reliable data and a finding of need. Solutions must be market-based and made for the benefit of New England consumers while also considering a reasonable cost burden.

Finally, any proposed solutions should be evaluated by conducting a full analysis of cost, benefits, and risks, including a customer bill impact analysis, that shows how consumers are affected and demonstrates that they would be better off under the proposed solution.

Respectfully submitted,

MAURA HEALEY
ATTORNEY GENERAL OF
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Dated May 9, 2018

APPENDIX A

THE JOINT REQUESTERS' COMMENTS AND SCENARIO REQUESTS TO ISO-NE

February 15, 2018

By Electronic Mail (*mlyons@iso-ne.com*)

Peter Brandien, Vice President, System Operations
Marc Lyons, NEPOOL Reliability Committee Secretary
ISO-New England, Inc.
1 Sullivan Rd
Holyoke, MA 01040

Re: Request for Modification to ISO New England Operational Fuel-Security Analysis Assumptions and Analysis of Additional Scenarios

Dear Peter and Marc,

We, the undersigned NEPOOL Members and interested parties (together the "Joint Requesters") appreciate the opportunity to provide ISO-NE with our requests for additional analysis in conjunction with ISO-NE's Operational Fuel-Security Analysis issued for discussion on January 17, 2018 ("OFSA"). We request that ISO-NE include in the next draft of the OFSA report and associated presentation materials these additional scenarios. The full parameters of all requests summarized below are listed in detail for each request on the attached ISO-NE "Operational Fuel Security Analysis Assumption Request Form" ("Form").

Modification of Assumptions in Reference Case: The Joint Requesters request that ISO-NE modify the OFSA Reference Case. Because ISO-NE designed the Reference Case to "serv[e] as a baseline for comparison with other scenarios,"[1] it is vitally important that it accurately reflect "likely levels" of relevant system variables "if the power system continues to evolve on its current path."[2] As indicated below, and again in the Form (item 1), each of the following Reference Case variables should be modified as noted to reflect "levels that can reasonably be expected to materialize in New England given current trends"[3] if ISO-NE is to meet its stated standard for the study's baseline:[4]

- LDC Gas Demand growth = 0.7%/yr
- Electric EE = Use 2018 EE Forecast
- Gross Load forecast = Use draft 2018 CELT
- Active DR = 500 MW
- Imports = 3,500
- LNG Cap = 1.25 Bcf/day

[1] *See* OFSA at p.8 ("The study includes . . . 1 reference case [that] incorporates likely levels of each variable if the power system continues to evolve on its current path, serving as a baseline for comparison with other scenarios.").
[2] *Id.*
[3] *Id.* at 22 ("The study's reference case incorporated each of the five key variables at levels that can reasonably be expected to materialize in New England given current trends.").
[4] To the extent ISO desires to analyze the effects of any of these system variables not reaching the reasonably expected levels indicated in this request, the Joint Requesters suggest ISO examine any such shortfall as an additional sensitivity from the updated Reference Case.

- PV = 4,990 MW
- Onshore Wind = 1,453 MW
- Offshore Wind = 430 MW

OFSA with Updated Reference Case + New Scenarios: After updating the Reference Case to include the modified variables indicated above (item 1), the Joint Requesters request that ISO-NE re-run all 23 scenarios (the Reference Case and 22 others) included in the Preliminary OFSA. In addition, the Joint Requesters ask that ISO also run the ten new Single-Variable and Combination Case scenarios listed on the Request Form (items 2-11) against the Updated Reference Case.

Alternative Approach: Only if ISO determines it cannot re-run the OFSA using the Updated Reference Case described above, the Joint Requesters ask that ISO-NE create and run a new "Business As Usual" ("BAU)" Case that modifies the draft reference case variables as requested for the Corrected Reference Case (item 1). Should ISO-NE proceed in this manner, the Joint Requesters ask that ISO-NE also run the fifteen new BAU-related cases listed on the Request Form (items 2-11 plus items 12-16) in addition to a new BAU Case.

General Information Requests: On the Form, Joint Requestors also list requests for the report to be clarified or additional information to be provided in 12 areas relevant to ISO-NE's development of the Preliminary OFSA. The Joint Requestors thank ISO-NE in advance for providing these clarifications and requested information which will help the Joint Requestors better understand the OFSA and which the Joint Requestors believe will maximize the value of the OFSA for all NEPOOL stakeholders.

Thank you for considering this request. Questions regarding this request should be directed to the Joint Requesters by contacting Sarah Bresolin (sarah.bresolin@state.ma.us; 617.963.2407) or Abigail Krich (607-227-8100; krich@boreasrenewables.com).

Sincerely,

MASSACHUSETTS ATTORNEY GENERAL'S OFFICE

//s//

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Assistant Attorney General

NEW HAMPSHIRE OFFICE OF THE CONSUMER ADVOCATE

//s//

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Consumer Advocate

RENEW NORTHEAST

//s//

Francis Pullaro
Executive Director

CONSERVATION LAW FOUNDATION

//s//

David Ismay
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BROOKFIELD RENEWABLE

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Senior Director, Regulatory Affairs –
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Deputy Regional Director

UNION OF CONCERNED SCIENTISTS

//s//

Mike Jacobs
Senior Energy Analyst

VERMONT ENERGY INVESTMENT CORPORATION

//s//

David C. Westman
Director, Regulatory Affairs

<table>
<tr><th colspan="4">Operational Fuel-Security Analysis Assumption Request Form</th></tr>
<tr><th>Scenario Number
Or Input Description
(i.e. – Reference Case,
Scenario #1-23,
Specific Input Variable,
Other Request)</th><th>Commenter
(Name/Organization)</th><th>Detailed Request for Change Input or Key Assumption
(i.e. – what is the requested input value)</th><th>Rationale or Basis
for Detailed Request</th></tr>
<tr><th colspan="4">New Case Requests</th></tr>
<tr>
<td>1.
Update the reference case with these modified assumptions and re-run all 23 cases based on the updated reference case. Additionally, run the below cases numbered 2-11 that <u>do not include</u> an asterisk, modifying the noted assumptions from the updated reference case. (Note that cases 12-16 below with an asterisk are not needed if the reference case is updated and all of the original 23 cases are re-run.)

-or-

In the alternative, create a new “Business as Usual (BAU)” case as shown here and run the additional cases 2-16 below (both those that do and do not include an asterisk).</td>
<td>Joint Requesters</td>
<td>Update the following assumptions from the ISO’s reference case:

LDC Gas Demand growth = 0.7%/yr

Electric EE = Use 2018 EE Forecast

Gross Load forecast = Use draft 2018 CELT

Active DR = 500 MW

Imports = 3,500

LNG Cap = 1.25 Bcf/day

PV = 4,990 MW

Onshore Wind = 1,453 MW

Offshore Wind = 430 MW</td>
<td>LDC Gas Demand Growth – Use recent growth rates as future projection
An analysis of recent EIA gas data since 2010, normalized for weather, appears to show an annual LDC gas use growth rate in recent years of approximately 0.7%/yr, reduced from the 1.26% used in ISO’s draft reference case. There does not appear to be sufficient evidence to support a near doubling of this growth rate in the coming years.

Electric EE – Use 2018 forecast
Draft 2018 EE forecast, using updated methodology, shows energy demand reduction from passive EE increased substantially as compared with the 2017 forecast as shown in the following table. ISO should use their own most current information.
Incremental energy savings from PDR in New England (GWh)
<table>
<tr><th></th><th>CELT 2017
(final May 2017)</th><th>CELT 2018
(draft Feb 2018)</th></tr>
<tr><td>Through 2017</td><td>11,903</td><td>-</td></tr>
<tr><td>2018</td><td>1,376</td><td>(per 2017 CELT)</td></tr>
<tr><td>2019</td><td>1,632</td><td>2,690</td></tr>
<tr><td>2020</td><td>2,127</td><td>2,568</td></tr>
<tr><td>2021</td><td>2,403</td><td>2,498</td></tr>
<tr><td>2022</td><td>2,218</td><td>2,306</td></tr>
<tr><td>2023</td><td>2,024</td><td>2,104</td></tr>
<tr><td>2024</td><td>1,825</td><td>1,898</td></tr>
<tr><td>Total</td><td>25,508</td><td>27,343</td></tr>
</table>

Gross Load Forecast – Use 2018 forecast
The 2018 draft load forecast resulted in a significant decrease in the gross load based on more recent system trends as discussed at the 2/13/2018 RC (A7, slide 10 shows 2022 summer peak is reduced by 2.1% in draft 2018 forecast compared with 2017 forecast). ISO should use their own most current information.

Active DR – Use quantity based on FCA 12
FCA 12 concluded with 458 MW existing active DR, 51 MW new Active DR, just over 500 MW</td>
</tr>
</table>

			in total. ISO should base this assumption on the most current information available from FCA 12. While Active DR typically shed much of its CSO following the FCA in the early years of the FCM, this does not appear to be the case in recent years. The Feb 2018 COO report on pp. 54-57 shows that the amount of CSO for Active DR appears to be holding fairly steady at the level requested here for some time. **Imports** – The MA 83D solicitation will procure resources able to deliver approximately 1000 MW on average, whether from imports or another clean energy resource type, for delivery beginning by 2022. Though there is uncertainty right now about which project will ultimately receive a contract, there is very little uncertainty that one of the 46 bids received in the solicitation will move ahead and be in service by 2024. Including this in the business as usual case is consistent with the ISO's premise for requiring that CASPR be in place for FCA 13. **LNG Cap** ISO has seen 1.25 Bcf/day flow, and a future that envisions retirement of nuclear, oil, and coal units may require more LNG. The LNG providers have shown that they can flow this amount. **PV – Use 2018 forecast** Draft 2018 PV forecast released 2/5/2018 shows 4,990 MW in 2024, increased from 4,432 MW in 2017 PV forecast. ISO should use their own most current information. **Onshore Wind** 2017 CELT report shows 1300 MW onshore wind operating as of 1/1/2017. Interconnection queue shows another 53 MW achieved COD between in 2017. Assume an additional 100 MW added for total of 1453 MW. **Offshore Wind** - With above renewables assumptions, approximately 400 MW new offshore wind is needed to meet the growth in RPS requirements between now and the study year (approximately 5.1 TWh, see further explanation on assumed capacity factors below). This is a reasonable, achievable projection given the ongoing MA 83C offshore wind solicitation. **Capacity Factors – The above MW numbers assumed to meet the growth in RPS requirements are based on the following annual CF assumptions:** **Onshore Wind** – 32%, as used by ISO in the FCA 12 ORTP calculation **Offshore Wind** – 44.5%, as used by ISO in the 2015 economic study of offshore wind **PV** – 14.4%, as used by ISO in the 2017 PV forecast (Note, the average winter CF from Dec – Feb is shown to be about 7.64%)
2. **Create "BAU + Higher LDC Gas Demand Growth" case**	**Joint Requesters**	**Increase LDC gas demand forecast value to the 1.26%/yr**	**Show impact of changing single-variable of LDC gas demand growth to the higher value of 1.26%/yr assumed in ISO's draft Reference case.** The draft report, page 25, says that LDC gas demand growth is assumed to grow from 515 Bcf/yr in 2014 to 591 Bcf/yr in 2025. That is an annual growth rate of 1.26%.
3. **Create "BAU +**	**Joint Requesters**	**Increase Thermal EE by reducing**	**Show impact of changing single-variable of LDC gas demand growth. This slower growth rate could result from more aggressive thermal EE programs.**

Increased Thermal EE" case		**annual LDC gas demand growth from 0.7%/yr in Business as Usual to 0.5%/yr.**	
4. Create "BAU + Accelerated Renewables" case	**Joint Requesters**	**PV = 5,442 MW** **Offshore wind = 1,630 MW** **Onshore wind = 2,553 MW** **Other Renewables = 960 MW**	**Show impact of changing the single variable of renewables development accelerated to 2024 compared with the BAU case. (Total 10585 MW total)** **PV** – Pre-discounted ISO-NE 2018 PV forecast for 2024 is 5,442 MW **Offshore Wind** – Assumes full MA 83C solicitation for 1,600 MW built on accelerated schedule by 2024. **Onshore Wind** – Assumes existing 1,353 MW increased by 1,200 MW, the size limit of a single Maine cluster. **Other Renewables** – Leave at existing levels
5. Create "BAU + Increased Electric EE" case	**Joint Requesters**	**Increase Electric EE from Business As Usual case by 1180 MW**	**Show impact of changing single-variable of electric demand on BAU case.** The 2016 Economic Study (NEPOOL Scenario Analysis) Scenario 3 value for EE in 2025 was 5,663 MW. This is 1,180 MW higher than ISO's draft 2018 CELT value of 4,483 MW. This represents a 26% increase in EE peak demand reduction.
6. Create "BAU + Battery Storage" case	**Joint Requesters**	**Add 250 MW/500 MWh battery storage with 89% round trip efficiency to Business as Usual case**	**Show impact of changing single-variable of adding battery storage.** **This level of storage is expected to be developed in the next 2-3 years, and is a conservative assumption for what might be built by 2024 but would show directionally the impact that storage might have.** • **MA is mandated to have 200 MWh battery storage installed by 2020.** • **Solar Massachusetts Renewable Target (SMART) is expected to drive the development of a larger quantity of storage alongside the PV developed under that program.** • **Advancing Commonwealth Energy Storage program has awarded grants to 26 storage projects totaling 25 MW/59 MWh.** **Model storage as a resource of last resort to be discharged prior to load shedding and charged at the next opportunity when gas/LNG is available. While this is different from how these first storage installations are likely to operate, it will provide an indicator of the level of support short-term storage may be able to provide towards achieving greater winter grid resiliency.** **Assume 89% round trip efficiency (the efficiency of the currently available Tesla 4-hour Power Pack).**
7. Create "BAU + Increased Security	**Joint Requesters**	**BAU with the Accelerated Renewables,**	**Show the impact of the combination of changes that increase system security based on BAU assumptions**

Combination" Case		**Increased Electric EE, Increased Thermal EE, Battery Storage, more dual fuel tank refills, and More LNG**	

**8.
Create "Accelerated Renewables + CASPR Success" Case**
	Joint Requesters	**Assume increased retirements of 2849 MW above BAU case, corresponding to summer capacity value of new renewables and imports added in Accelerated Renewables Case**	**CASPR and the FCM should generally cause the market to keep a balance between retirements and new sponsored policy resource additions if they work as intended. Assume that the FCA qualified capacity value of the new renewables and imports added to the system in the Accelerated Renewables case are offset by retirements totaling the same capacity value.**
			• 5,443 MW total – 2400 MW existing = 3,042 MW new PV
			    ○ 30% qualified capacity = 913 MW new PV capacity
			• 1,630 MW total – 30 MW existing = 1,600 MW new offshore wind
			    ○ 45% qualified capacity = 720 MW new offshore wind capacity
			• 2,553 MW total – 1,353 MW existing = 1,200 MW new onshore wind
			    ○ 18% qualified capacity = 216 MW new onshore wind capacity
			• 3,500 MW total – 2,500 MW existing = 1000 MW new imports
			    ○ 100% qualified capacity = 1000 MW qualified capacity value
			• Total new capacity = 2849 MW.
			Assume additional retirements of 2849 MW.

9. Create "BAU + Add'l Retirements" Case	**Joint Requesters**	**BAU with same number of MWs of retirements as in the CASPR success case (2849 MW increase over BAU), but without the increased renewables**	**Show impact of changing single-variable on BAU assumptions**
10. Create "BAU + Add'l Retirements + Add'l LNG" Case	**Joint Requesters**	**BAU with same number of MWs of retirements as in the CASPR success case (2849 MW increase over BAU), but without the increased renewables, and LNG cap increased to 1.5 Bcf**	**Show impact of changing increasing LNG cap on the add'l retirements case.**

11. Create "BAU + Compressor Outage + Counteracting Changes"	**Joint Requesters**	**BAU with compressor outage, 1.5 Bcf LNG, 3 dual fuel tank refills, accelerated renewables, Increased Electric and Thermal EE**	**Shows impact of compressor outage with counteracting changes to system**
12.* Create "BAU + More LNG" Case	**Joint Requesters**	**Increase LNG Cap in Business as Usual case to 1.5 BcF**	**Show impact of changing single-variable of increased LNG injection cap.** Note: If the reference case is updated, the "More LNG" case (original case #3 in the draft OFSA) would add 0.25 Bcf/day to the LNG cap as in the original Case #3, resulting in a new cap of 1.5 Bcf in the updated Case #3. A new More LNG case would only be needed if the reference case is not updated.
13.* Create "BAU + More Dual Fuel Replenishment"	**Joint Requesters**	**BAU plus 3 dual fuel tank fills instead of 2**	**Show impact of changing single-variable of dual fuel tank fills.**
14.* Create "BAU – Imports" Case	**Joint Requesters**	**Decrease imports from BAU case to 2500 MW**	**Show impact of changing single-variable of imports remaining at today's levels rather than increasing to the BAU level.** Note: If the reference case is updated to include 3500 MW imports, the "less imports" case (original case #7 in the draft OFSA) would be run with 2500 MW imports rather than 2000 MW imports.
15.* Create "BAU + Max Retirements" Case	**Joint Requesters**	**BAU with 5400 MW retirements**	**Show impact of changing single-variable on BAU assumptions**
16.* Create "BAU + Compressor Outage"	**Joint Requesters**	**BAU with compressor outage, 1.5 Bcf LNG, 3 dual fuel tank refills**	**Shows impact of compressor outage, coupled with increased LNG and dual fuel tank refills as in ISO draft study scenario 22.**
			General Requests
Clarification of how model uses annual and peak LDC gas demand assumptions	**Joint Requesters**		Page 25 of the draft report (and slide 25 of the January presentation) notes that the ICF study forecasted peak LDC gas demand rising from 4.4 Bcf/day in 2014 to 5.45 Bcf/day in 2025. This is a 24% overall growth (2% annually). Please clarify why the assumption that peak gas demand would grow 24% while the annual gas demand grows 14.7% is reasonable. Please clarify how the ISO's model utilizes the annual and peak day gas demand values of 591 Bcf/yr and 5.45 Bcf/day. If it is taking a gas demand profile from the winter of 2014/15 (if so, where does that profile come from), how is ISO scaling that up to match both the annual demand and also the peak

			demand?
Clarification on annual LDC gas demand growth	**Joint Requesters**		The draft ISO report, page 25, says that LDC gas demand growth is assumed at “just under 2%”, growing from 515 Bcf/yr in 2014 to 591 Bcf/yr in 2025. That is an annual growth rate of 1.26% and total growth of 14.7%. This should be clarified as it was widely interpreted to mean that ISO had assumed a 2% annual growth rate, or 24% total growth from 2014 to 2025. It should be clear that a 1.26% annual growth rate was assumed rather than saying “just under 2%”.
Update PV and onshore wind profiles used in models to correspond to load profile	**Joint Requesters**	**Update PV and onshore wind profiles**	Load profiles are driven by weather conditions, just as PV and wind profiles are. By using PV and wind profiles from a different year than the load profile year, ISO has removed the correlation between these profiles and the common weather driving them all. ISO has access to hourly meter data for the onshore wind and registered PV projects operating in the winter of 2014/2015 and should use those profiles, scaled up to the quantities envisioned in these assumptions, rather than using wind and PV profiles from a different year than the load profile used in the study.
Update characterization of onshore wind	**Joint Requesters**		There are 1353 MW of onshore wind resources currently operating on the system. ISO’s materials incorrectly represent 1200 MW as the quantity operating in 2017 and should be updated (e.g., the following quote from page 26). Page 26 of the draft report says “Some scenarios assumed higher levels of offshore wind and behind-the-meter solar because these resources appear to have the greatest growth potential, driven by state policies and incentive programs. Onshore wind was held at the current level throughout the study timeline, given the transmission expansion that would be required to develop more onshore wind farms.” This study, as represented by ISO, is not intended to cast judgments on the probability of any particular outcome. Similarly, this language should be revised so as not to represent that certain resource types have greater growth potential than others, as this is not necessarily the case.
Correct BTM PV references	**Joint Requesters**		The PV numbers come from the PV forecast which is an aggregate forecast for all types of PV development in New England, not just BTM PV which is a subset. References to BTM PV should be updated to reflect this.
Rename “Max Renewables” assumption “High Growth Renewables”	**Joint Requesters**		The assumptions used in this case are not the maximum quantity of renewables that could be developed by 2024/25 and the name of this assumption is therefore misleading. “High Growth Renewables” would be more appropriate. Similarly, update all references in the materials to these cases representing all or more than the renewables that could result from existing or future clean energy initiatives of the New England states (page 53 in particular). These scenarios do not represent more renewables than could be developed based upon current or possible future state initiatives.
No probabilities, even for boundary cases.	**Joint Requesters**		Make clear throughout the report and materials that there are no probabilities associated with any of these cases and that selecting a variety of cases that show negative outcomes does not indicate that the system is trending in a dangerous direction but simply that if this situation were to occur it could be problematic. Similarly, remove commentary related to the boundary cases being the only ones that are “unlikely to materialize” (Figure 4 and pages 37, 44, 48, 51, 53).

Re-characterize boundary cases	**Joint Requesters**		For the boundary cases, change the description from the “best and worst outcomes” on page 37 of the draft report to “most and least secure” or some other more objective description.
Clarify transmission expansion comments	**Joint Requesters**		The draft report materials (slide 13 of presentation) seem to state that expansion of the transmission system would be required for the renewables cases assumed by ISO when in fact, no significant transmission buildout requirement would be expected for these cases. Only the addition of the 1000 MW of imports shown in the BAU/More Imports cases and the 1200 MW of additional onshore wind shown in the accelerated case here, would require significant transmission expansion.
Copper sheet	**Joint Requesters**		Clarify in the report that the model assumed a copper sheet (i.e., no transmission constraints) for the transmission system and therefore no specific locations for new additions or retirements were assumed.
Update commentary on NY pipeline expansions	**Joint Requesters**		The draft report notes on page 15 that further construction of additional pipeline in NY, which frees up incremental capacity into New England, will likely prove difficult and therefore assumes none will happen. However, the ICF study from October 2016 that ISO used as the basis for its pipeline capability assumptions noted that other projects under development appeared to be proceeding. Though opposition to specific NY pipeline expansions has been substantial (for the Constitution project in particular), it has not been universal and three such additional expansions in NY have now been built or approved. These three should be included in the assumptions for the system that will exist in 2024/25. These are: • New Market Project (already in service) - 112 MMcf/d • Millennium Eastern System Upgrade - 200 MMcf/d • Northeast Supply Enhancement - 400 MMcf/d
Caveats	**Joint Requesters**		Page 20 of the draft report says “While this study doesn’t directly consider fuel costs or prices, it does assume that the electricity and fuel markets send price signals sufficient to make full use of the existing electricity and fuel infrastructure as needed.” Given the study’s reliance on past LNG injections rather than LNG injection capability should the pricing signal be right, for example, it is not clear that the study actually does assume that the infrastructure is fully used.

APPENDIX B

ISO-NE PRESENTATION TO THE NEPOOL RELIABILITY COMMITTEE SHOWING RESULTS OF STAKEHODLERS' SCENARIO REQUESTS

Operational Fuel-Security Analysis

Stakeholder Requests for Additional Scenarios

Operational Fuel-Security Analysis: Stakeholder Requests

- In January 2018, ISO-NE issued the Operational Fuel-Security Analysis to improve the ISO's and the region's understanding of operational risks and inform subsequent discussions with stakeholders
- Stakeholders were provided an opportunity to submit requests for additional hypothetical sensitivities to the ISO's study
- By mid-February, the ISO received requests equating to hundreds of new scenario combinations in the operational model

Operational Fuel-Security Analysis: Stakeholder Requests, cont.

- Due to the volume of requests, the ISO was not able to prepare an individual analysis to address every item; however, a significant number (~150) of additional runs of the model were conducted based on the requests received
- Graphical depictions, providing directional information about expected energy shortfalls when the sensitivities are shifted up or down, have also been created to provide stakeholders with additional information on the region's reliability challenges presented by different scenarios requested

Presentation Outline

- Section 1: General Comments and Clarifications
  - Addresses requests for general explanations or clarifications of ISO-created Scenarios
- Section 2: Graphic Depictions of Changes to Inputs
  - Addresses requests for changes to various input assumptions by grouping similar requests and showing directional trends
- Section 3: Specific Scenario Results
  - Reports results of stakeholder-requested model runs that ISO was able to conduct

SECTION 1:
GENERAL COMMENTS & CLARIFICATIONS

Caveats for the Operational Fuel-Security Analysis

- The Operational Fuel-Security Analysis is a ***deterministic*** analysis that provides ***directional guidance; it is not a forecast or prediction of actual future events***
- The Operational Fuel-Security Analysis ***does not reflect the potential for market response*** to pricing or other incentives
  - While the study did not explicitly consider specific market responses, the ISO assumed that prices in each scenario would sustain the inputs to that scenario
- The Operational Fuel Analysis does not evaluate impacts of the sudden draw-down of oil or LNG

Certain Limitations or Constraints not Addressed by the Model

ISO's model is not capable of modeling:

- State emissions limitations or goals
- Local constraints on the electric transmission or gas transportation systems
- Market response to pricing or state-mandated purchases

Note: If a stakeholder request provided a proxy for such scenarios using the model's inputs or variables, the ISO ran it through the model

Requested Clarification on Modeling of Mystic and Distrigas

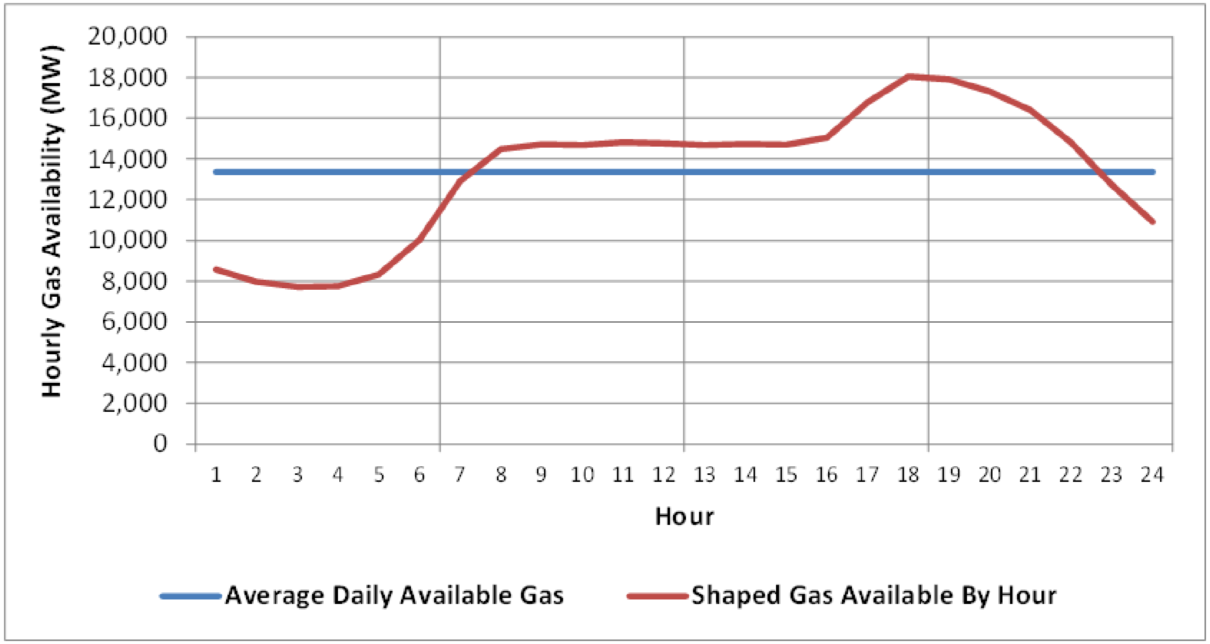
- The model assumed Distrigas can support a LNG vaporization rate capable of providing the full output needed for Mystic 8 and 9 *and* simultaneously allow pipeline injections
  - Enough fuel for Mystic 8 and 9 at full output
  - Plus 0.435 Bcf/d injections
    - 0.3 Bcf/d into Algonquin and Tennessee
    - 0.135 Bcf/d into the local gas utility distribution system
- LNG vaporized to provide fuel for Mystic 8 and 9 is in addition to the LNG injection caps used in any of the 23 scenarios in the Analysis
  - LNG injection caps apply only to sources injecting into the interstate pipelines ***and do not consider locational factors***
  - When Distrigas is out of service, the Mystic units are also out of service

Requests for Clarification on Inclusion/Exclusion of Specific Pipeline Expansion Projects

- The only pipeline expansion projects included in the assessment were based on the ICF International analysis
  - Specifically those that were to be completed in the study horizon **and** that would add incremental pipeline capacity to the existing infrastructure
    - Ex: Portland Natural Gas Transmission System expansion (0.3 Bcf/d), Continent to Coast (0.21 Bcf/d), and Portland Express (0.3 Bcf/d)
- Excludes those that do not add capability directly into New England such as the New Market Project, Millennium Eastern System Upgrade, and Northeast Supply Enhancement, which are New York pipeline expansions
  - Note: If stakeholders provided a proxy for such scenarios using the model's inputs or variables, the ISO ran it through the model

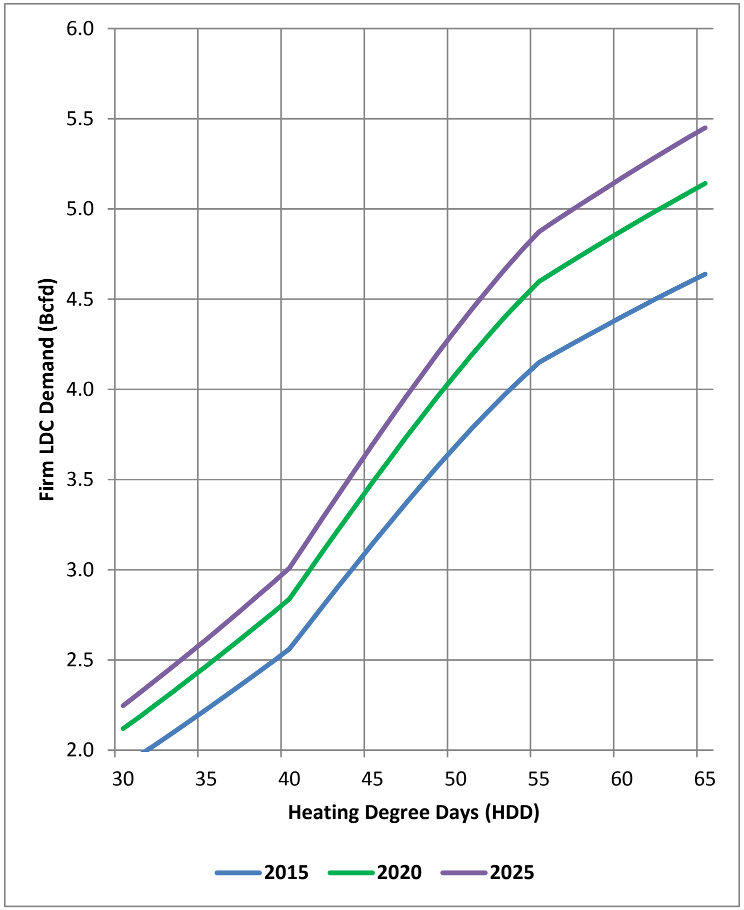
Requested Clarifications on LDC Demand and Gas Availability

- ICF developed a winter day gas demand vs. daily Heating Degree Day (HDD) curve that was then scaled up to the total New England gas demand forecast for Winter 2025
- As the chart shows, Daily Available Gas was shaped to reflect hourly gas usage. Gas availability profile was shifted from off-peak hours to on-peak hours to follow the hourly electric demand curve
  - (Total Daily Available Gas) = (Daily Pipeline Available Gas) + (Daily LNG Injections Available) + (Daily Satellite Gas Injections)
  - (Total Daily Available Gas for Generation) = (Total Daily Available Gas) – (New England Daily LDC Demand) – (New Brunswick Daily LDC Demand)
  - (Hourly Gas Available for Generation) = (Total Daily Available Gas for Generation)/ 24 * (Ratio of Hourly Electric Demand to Peak Demand for the Day)



Requested Clarifications on LDC Demand and Gas Availability, cont.

- LDC gas demand is highly correlated to the heating needs of a particular day and the heating needs over the entire winter. Low average daily temperatures, which translate to high degree days, drive up natural gas demand by gas LDCs and reduce the availability of gas for electric power generation
- The chart shows the assumed New England LDC gas demand as a function of temperature for 2015, 2020, 2025, and 2030. These curves are based on the April 2014 ICF gas demand model that estimated LDC gas demand as a function of HDD
  - LDC gas demand of 65 HDD based on the October 2016 ICF forecast

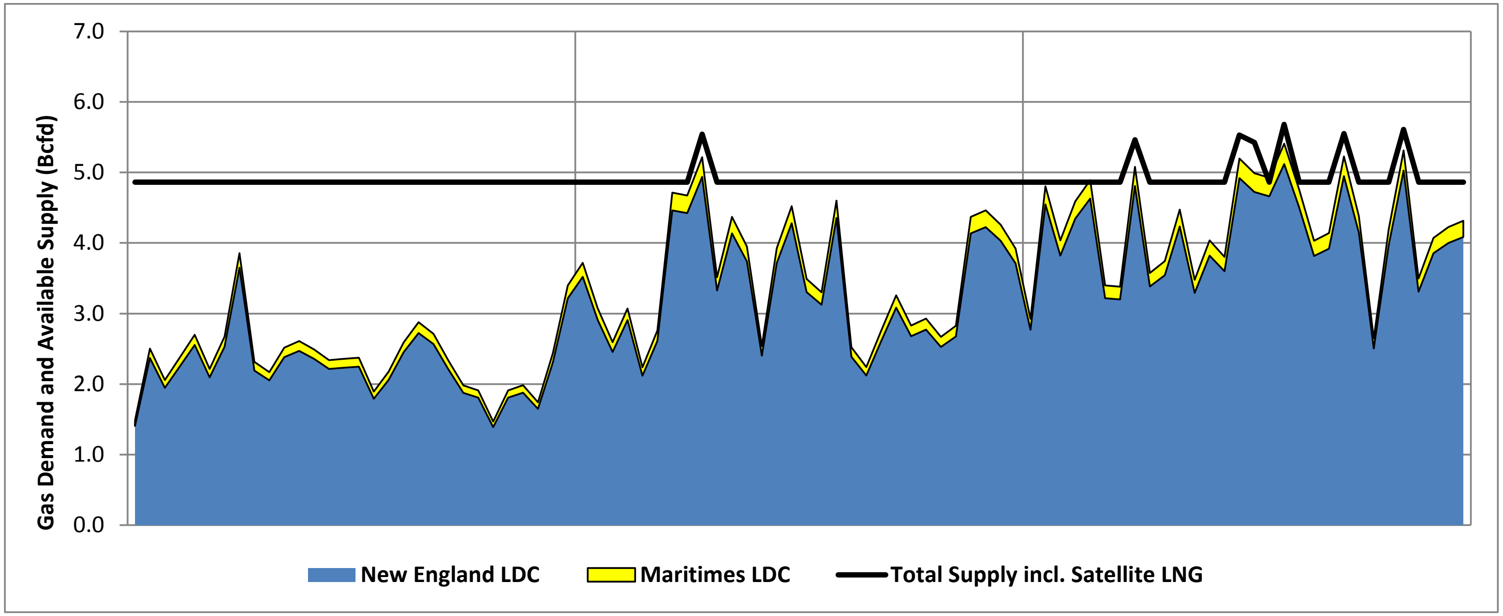


Requested Clarifications on LDC Gas Profiles and Assumptions Underlying LDC Demand

- The analysis assumed depletion of the Sable Island and Deep Panuke gas fields
- Therefore, the ICF analysis indicated that by 2024/2025, the Maritimes' LDC would likely be served entirely by LNG from Canaport or deliveries of pipeline gas imported from New York or Quebec via the M&N pipeline
- Because pipeline gas is typically less expensive than LNG, it was assumed that pipeline gas would be used before vaporization of LNG at Canaport, Distrigas, or the buoy
- If Maritimes demand is served by pipeline gas from the west, less natural gas would be available for New England
- Even if the Maritimes LDC gas demand is overstated, the combined gas consumption of the Maritimes (LDC plus power sector) seems to match observations and will, consequently, affect inventory draw-down

Requested Clarifications on LDC Gas Profiles and Assumptions Underlying LDC Demand, cont.

- The chart shows the gas demand of the LDCs (including commercial and industrial loads) in both New England and the Maritimes, and total supply
  - The total supply is based on the 3.860 Bcf/d of gas from pipelines from New York and Québec, plus an assumed cap on the amount of LNG vaporization set at 1.0 Bcf/d in the reference case, for a total of 4.860 Bcf/d available from pipelines and LNG import facilities
  - On cold days, local satellite LNG facilities are called into service to support the gas distribution system so that the total supply exceeds the pipeline gas plus the assumed LNG cap of 4.860 Bcf/d



LDC gas demand in 2024/2025 for New England and the Maritimes based on winter 2014/2015 weather (Bcf/d)

Requested Clarifications on Compressor Outage Scenario

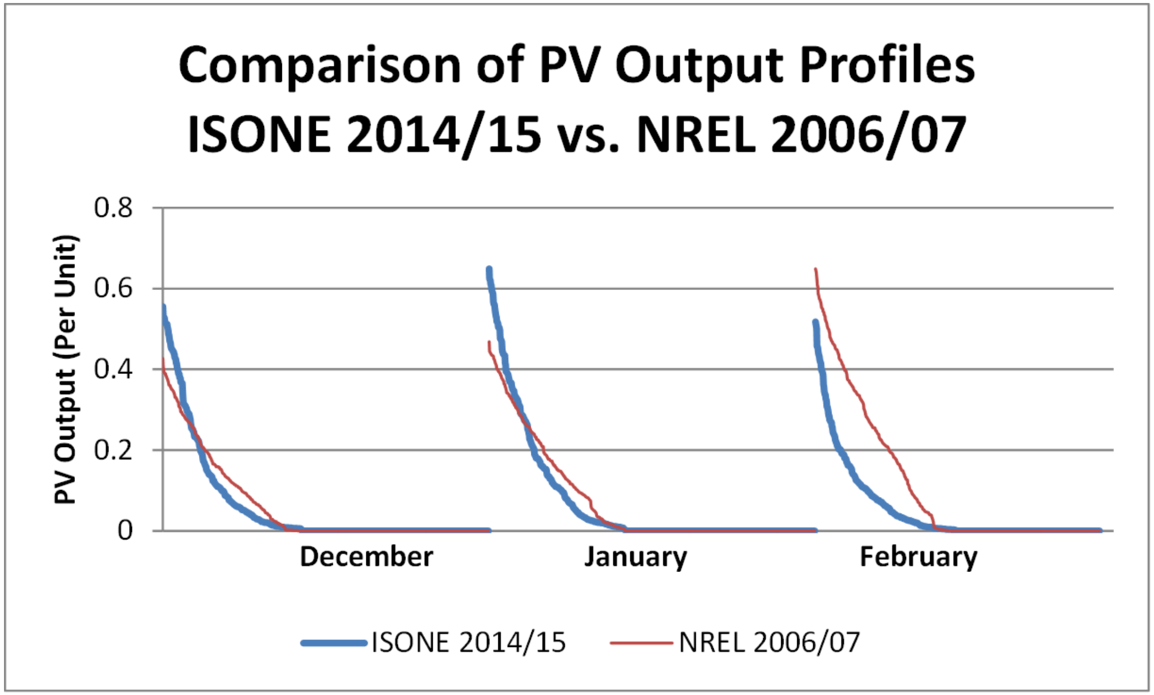
- The case labeled as “Compressor Outage” in the Analysis would have the effect of completely eliminating throughput at a single point on the pipeline
- The scenario represents several possible outages throughout the region and is not specific to any single point on any specific pipeline
  - Several gas companies noted that a pipeline outage would reflect the magnitude represented in the model, but may not last all winter, while a compressor outage may last all winter but not of the magnitude in the model
  - The “Compressor Outage” in the Analysis represents the general blend of these outcomes

Requested Clarifications on Hourly Loads Underlying the 90-Day Winter Load Scenario

- Although the entire winter of 2014/2015 was one of the coldest based on cumulative HDDs, the peak load day was much warmer than a "normal" winter peak load day
  - The actual temperature was 19°F compared with the 7°F temperature assumed for the 50/50 peak loads and the 1.6°F temperature assumed for a 90/10 winter peak load
- The 2014/2015 load shape was adjusted to the forecasted conditions in the 2024/2025 timeframe
  - In this future period, the New England system was modeled with an increase in winter gross loads countered by more energy efficiency that will result in a generally lower net load
- The 2014/2015 actual gross peaks are comparable in magnitude to the forecast 2024/2025 peaks. Additionally, the actual peak load in 2014/2015 was approximately equal to the 90/10 winter peak for the study year
  - Therefore, to model the 2024/2025 winter loads to reflect the 2014/2015 weather, the hourly profile was scaled up slightly by 0.8%

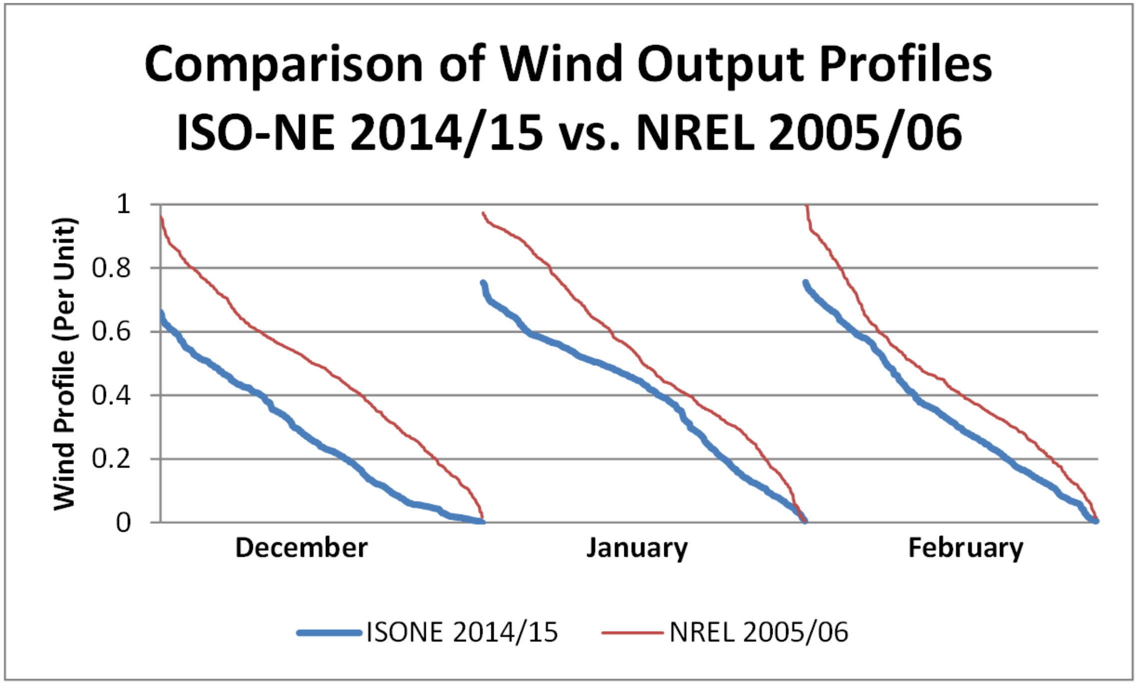
Requested Updates for PV and Onshore Wind Profiles

- The use of the higher National Renewable Energy Laboratory (NREL) PV output in the Operational Fuel-Security analysis would have tended to decrease the OP4/OP7 metrics slightly compared to the New England estimates of PV output



Requested Updates for PV and Onshore Wind Profiles, cont.

- The use of the higher NREL onshore wind output in the Operational Fuel-Security analysis would have tended to decrease the OP4/OP7 metrics slightly compared to the actual New England onshore wind output



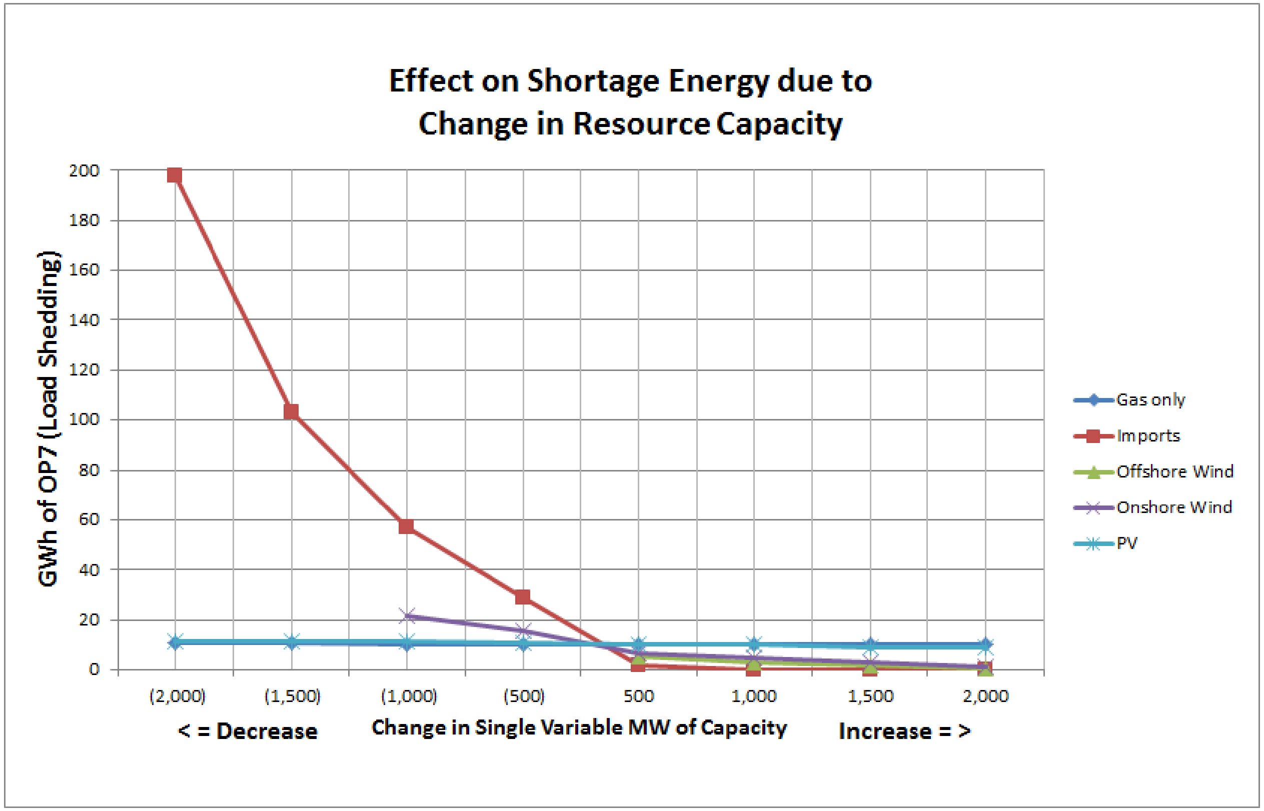
SECTION 2:
GRAPHIC DEPICTIONS OF CHANGES TO INPUTS

Sensitivity Charts

- The sensitivity charts below summarize the results of many requests for changes to input assumptions used in the Analysis
- Using the ISO Reference Case as a zero point, the charts show the expected energy shortfall impacts of increasing or decreasing a singular input value such as Gas Only Units, Imports, Peak Load Forecast, etc.
  - All are on a scale of zero to 200GWh
- Changes in Peak Load Forecast and LNG Injection/LDC Demand are on a different scales

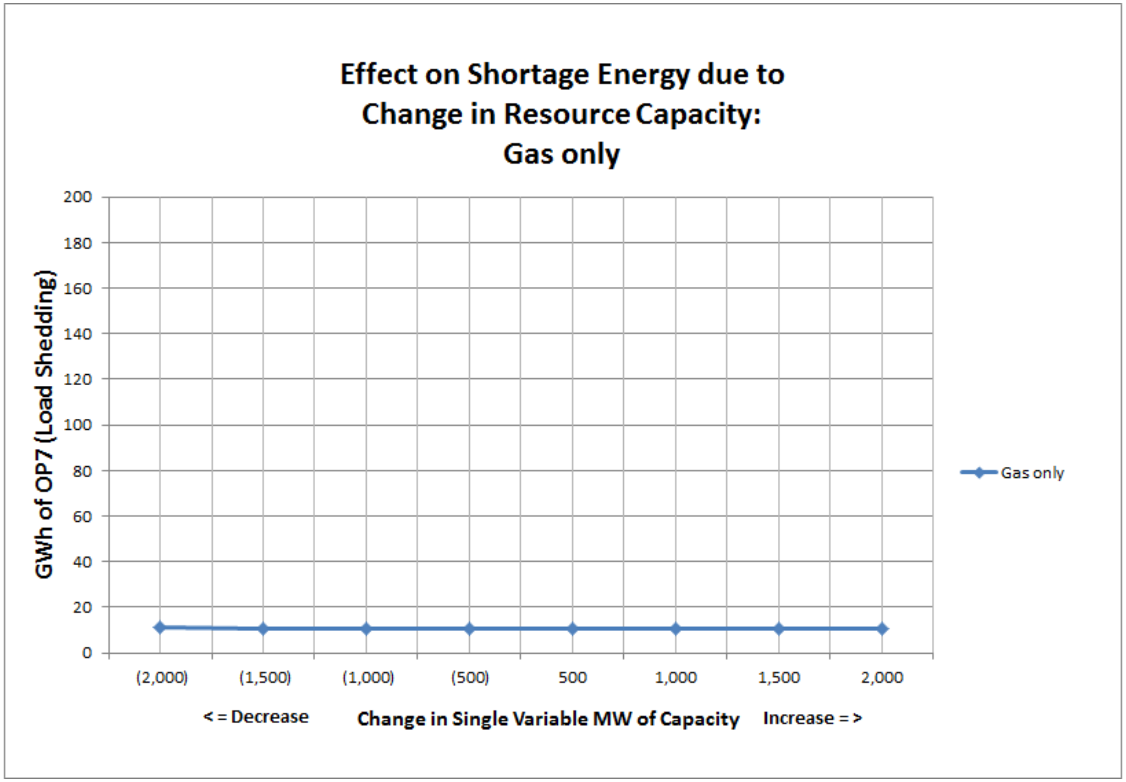
Effect on Energy Shortages due to Changes in Resource Capacity

- In general, several variables showed minimal effect on the expected energy shortages when adjusted, while others were more sensitive to shifts in resource capacity



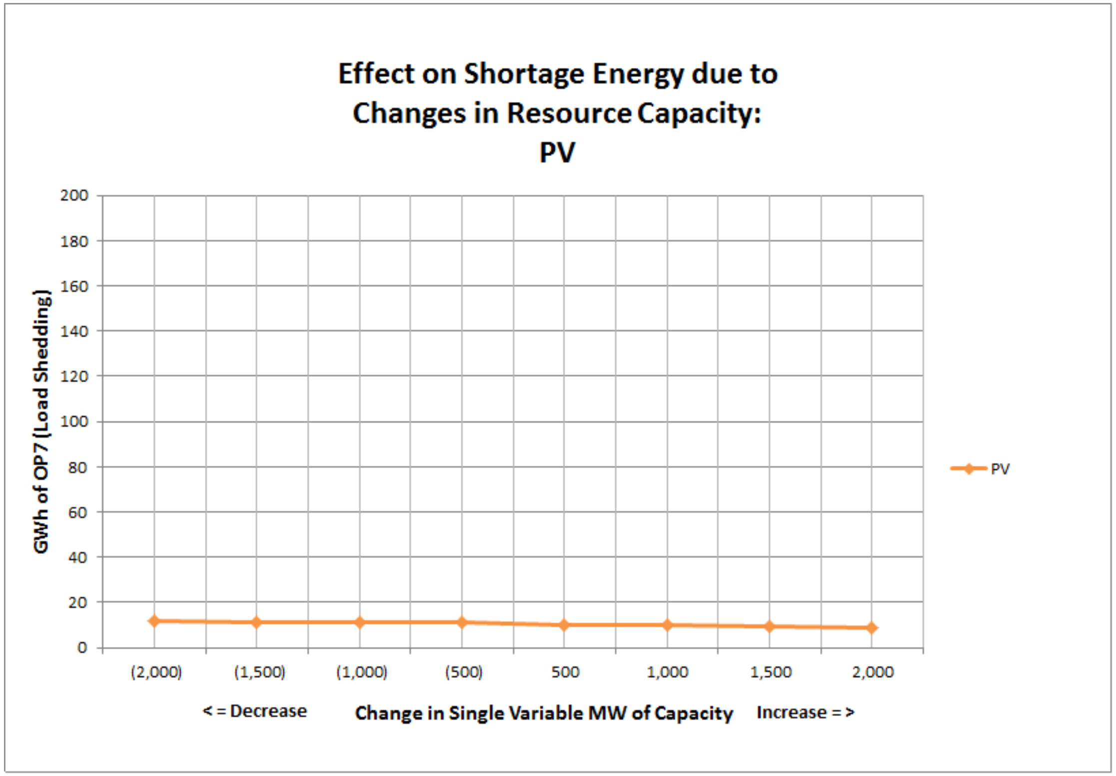
Effect on Energy Shortages due to Changes in Resource Capacity: Gas-Only

- As the gas-only units' capacity was adjusted, it showed no impact on the expected energy shortages in the Operational Fuel-Security Analysis



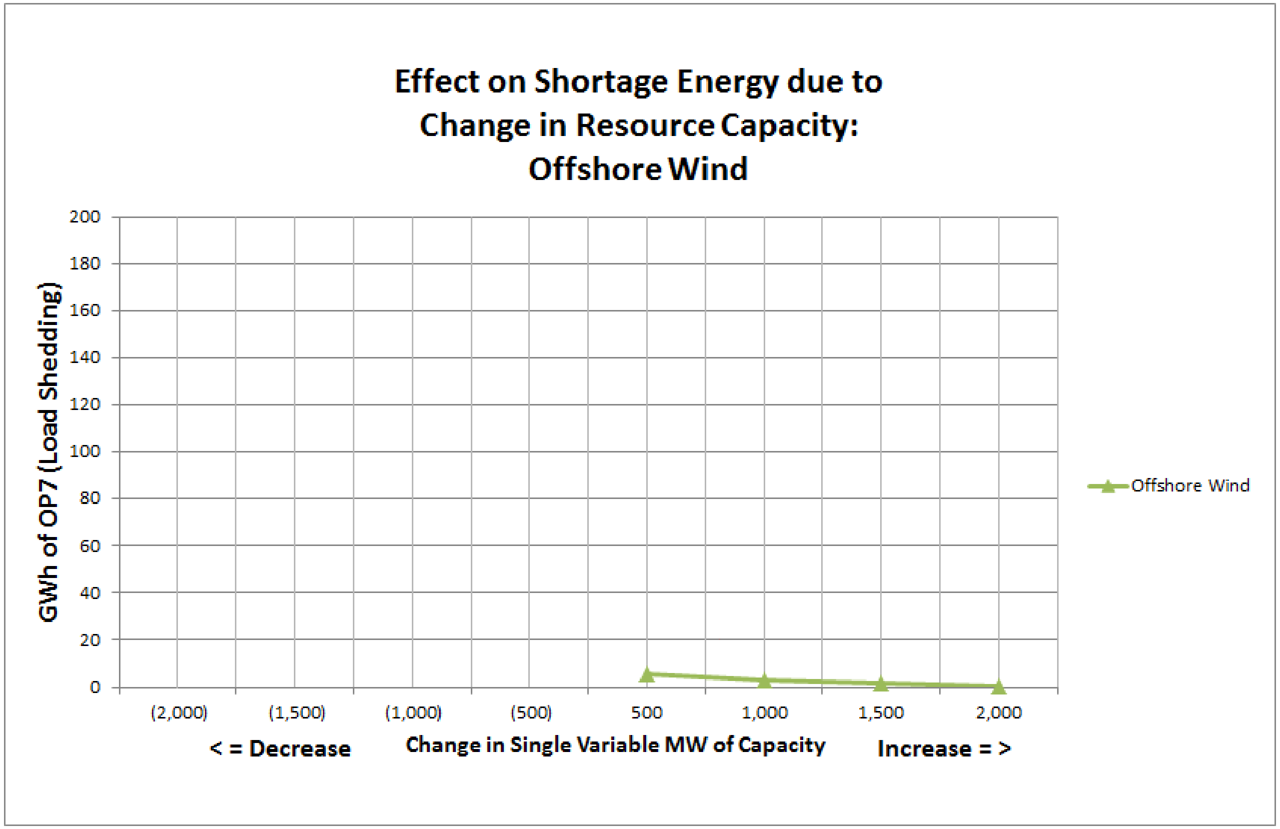
Effect on Energy Shortages due to Changes in Resource Capacity: PV

- As the PV units capacity was adjusted, it showed minimal impact on the expected energy shortages in the Operational Fuel-Security Analysis



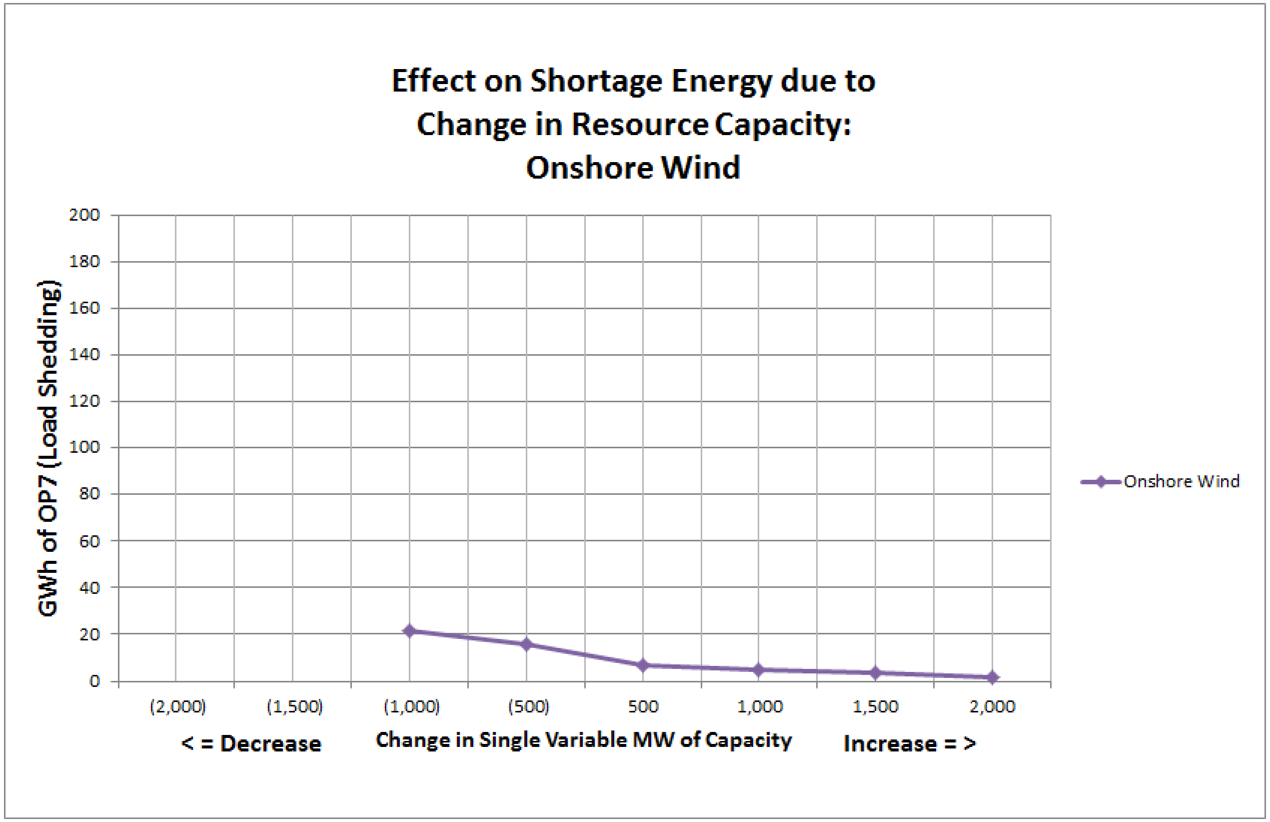
Effect on Energy Shortages due to Changes in Resource Capacity: Offshore Wind

- As offshore wind was adjusted, it showed decreases in the expected energy shortages if the offshore wind was increased



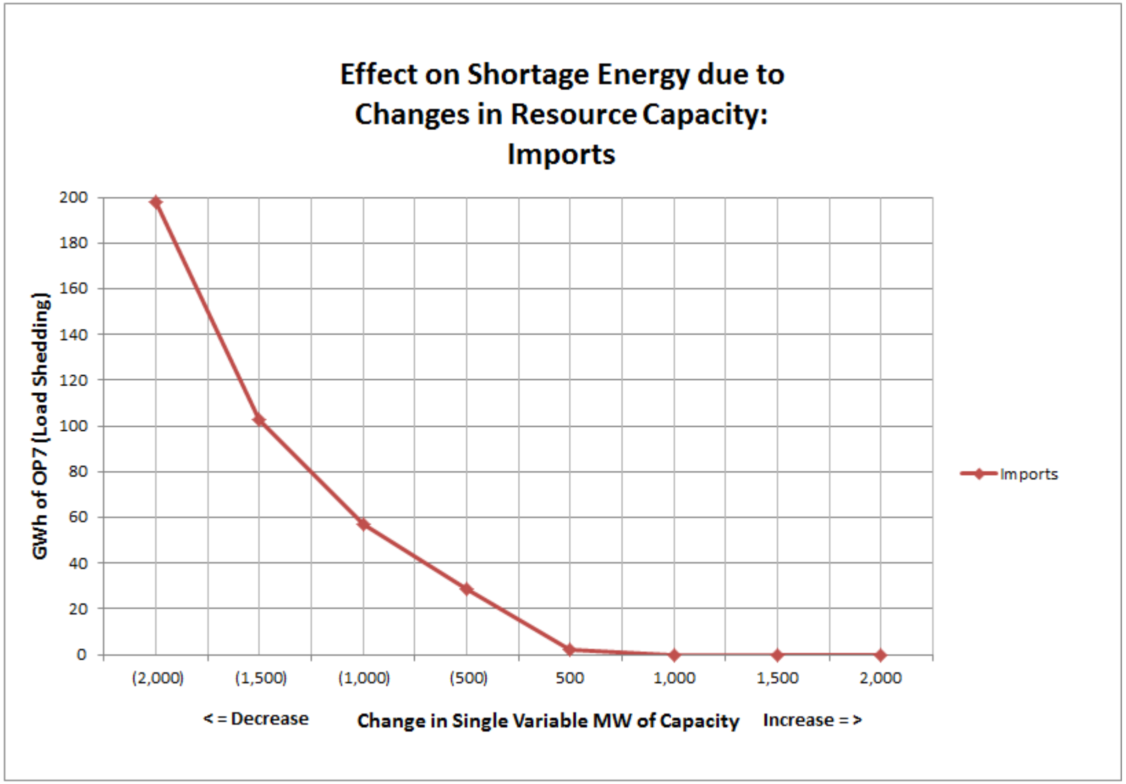
Effect on Energy Shortages due to Changes in Resource Capacity: Onshore Wind

- As onshore wind was adjusted, it showed increases in the expected energy shortages if the onshore wind was decreased



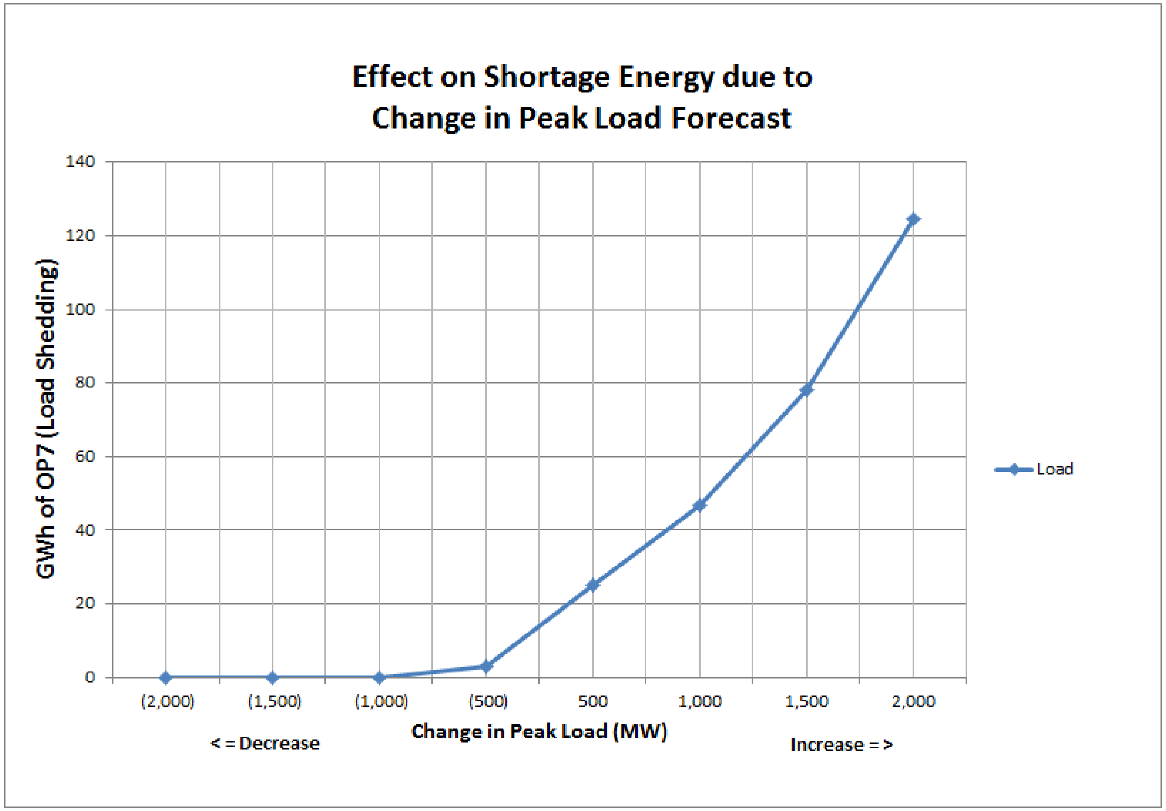
Effect on Energy Shortages due to Changes in Resource Capacity: Imports

- As imports were adjusted, it showed significant increases in the expected energy shortages if the imports were decreased



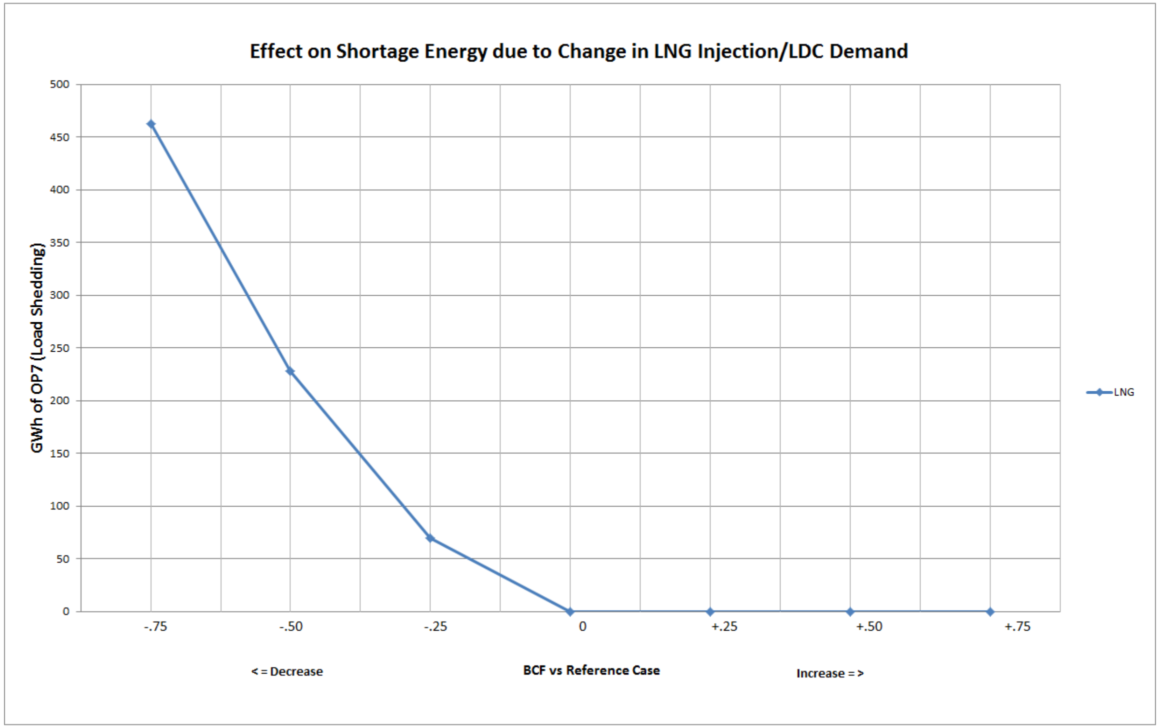
Effect on Energy Shortages due to Changes in Peak Load Forecast

- As the Peak Load Forecast was adjusted, it showed significant increases in the expected energy shortages if the forecast increased



Effect on Energy Shortages due to Changes in LNG Injection/LDC Demand

- As the LNG injection was adjusted, it showed significant increases in the expected energy shortages if the LNG injection was decreased
- Similarly if the LDC demand was adjusted, it would show significant increases in the expected energy shortages if the LDC demand was increased



SPECIFIC REQUESTED SCENARIOS

Scenarios Modeled

- The following slides summarize the results of scenarios run by the ISO based on requests received by February 15, 2018
- Scenarios are identified by a name provided by the requester or otherwise identifying the requester

JOINT REQUESTERS SCENARIOS

All scenarios are based on the "Joint Requesters Business As Usual (BAU) Scenario"

"Joint Requesters* #1: BAU" Scenario

- This scenario modifies the ISO Reference Case variables to reflect:
  - 0.7% annual LDC gas demand growth (vs. the 1.26% from ISO reference)
  - Increased Energy Efficiency (EE) by 73 MW
  - 500 MW of Active DR
  - 3,500 MW of imports (vs. 2,500 MW from ISO reference)
  - 1.25 Bcf/d LNG cap (vs. 1 Bcf/d from ISO reference)
  - 4,990 MW of PV based on a 14.4% capacity factor
  - 1,453 MW of onshore wind based on a 32% capacity factor
  - 430 MW of offshore wind based on a 44.5% capacity factor
- This scenario serves as a "Joint Requestors' BAU Reference" for all of the other Joint Requesters scenarios
- The label for each additional Joint Requesters' scenario was provided by the Joint Requesters

*The Joint Requesters include the 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.

“Joint Requesters #1: BAU” Scenario Summary

- This scenario serves as a "Joint Requestors’ BAU Reference" for all of the other Joint Requesters scenarios

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-

"Joint Requesters #2: BAU + Higher LDC Gas Demand Growth" Scenario Summary

- This scenario increased the LDC gas demand forecast from the "Joint Requestors' BAU Reference" to 1.26%/yr.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #2: BAU + Higher LDC Gas Demand Growth	-1,500	1.25	2	3,500	7,800	23	-	-	-	-	-

"Joint Requesters #3: BAU + Increased Thermal EE" Scenario Summary

- This scenario increased thermal EE from the "Joint Requestors' BAU Reference" by reducing annual LDC gas demand growth from 0.7%/yr. to 0.5%/yr.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #3: BAU + Increased Thermal EE	-1,500	1.25	2	3,500	7,800	9	-	-	-	-	-

"Joint Requesters #4: BAU + Accelerated Renewables" Scenario Summary

- This scenario modified the "Joint Requesters' BAU Reference" to reflect:
  - 5,442 MW of PV
  - 2,553 MW of onshore wind
  - 1,630 MW of offshore wind

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #4: BAU + Accelerated Renewables	-1,500	1.25	2	3,500	10,500	6	-	-	-	-	-

“Joint Requesters #5: BAU + Increased Electric EE” Scenario Summary

- This scenario increased electric EE from the "Joint Requestors’ BAU Reference" by 1,180 MW

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #5: BAU + Increased Electric EE	-1,500	1.25	2	3,500	7,800	5	-	-	-	-	-

“Joint Requesters #6: BAU + Battery Storage” Scenario Summary

- This scenario added 250 MW of battery storage to the "Joint Requestors’ BAU Reference"

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #6: BAU + Battery Storage	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-

"Joint Requesters #7: BAU + Increased Security Combination" Scenario Summary

- This scenario modified the "Joint Requestors' BAU Reference" to reflect "Accelerated Renewables," "Increased Electric EE," "Increased Thermal EE," "Battery Storage," 3 dual-fuel tank refills, and increased the LNG cap to 1.50 Bcf/d

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #7: BAU + Increased Security	-1,500	1.5	3	3,500	10,500	7	-	-	-	-	-

"Joint Requesters #8: Accelerated Renewables + CASPR Success" Scenario Summary

- This scenario increased retirements from the "Joint Requestors' BAU Reference" by 2,849 MW and included the "Accelerated Renewables"

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #8: Accelerated Renewables + CASPR Success	-4,349	1.25	2	3,500	10,500	12	-	-	-	-	-

"Joint Requesters #9: BAU + Add'l Retirements" Scenario Summary

- This scenario increased retirements from the "Joint Requestors' BAU Reference" by 2,849 MW

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #9: BAU + Add'l Retirements	-4,349	1.25	2	3,500	7,800	13	-	-	-	-	-

“Joint Requesters #10: BAU + Add’l Retirements + Add’l LNG” Scenario Summary

- This scenario increased retirements from the "Joint Requestors’ BAU Reference" by 2,849 MW and increased the LNG cap to 1.50 Bcf/d

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #10: BAU + Add’l Retirements + Add’l LNG	-4,349	1.5	2	3,500	7,800	4	-	-	-	-	-

"Joint Requesters #11: BAU + Compressor Outage + Counteracting Changes" Scenario Summary

- This scenario modified the "Joint Requestors' BAU Reference" to reflect a compressor outage, "Accelerated Renewables," "Increased Electric EE," "Increased Thermal EE," 3 dual-fuel tank refills, and increased the LNG cap to 1.50 Bcf/d

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #11: BAU + Compressor Outage + Counteracting Changes	-1,500	1.5	3	3,500	10,500	30	62	15	9	-	-

"Joint Requesters #12: BAU + More LNG" Scenario Summary

- This scenario increased the LNG Cap from the "Joint Requestors' BAU Reference" to 1.50 Bcf/d

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #12: BAU + More LNG	-1,500	1.5	2	3,500	7,800	4	-	-	-	-	-

“Joint Requesters #13: BAU + More Dual Fuel Replenishment” Scenario Summary

- This scenario increased the duel-fuel tank fills from the "Joint Requestors’ BAU Reference“ to 3 duel-fuel tank fills

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #13: BAU + More Dual Fuel Replenishment	-1,500	1.25	3	3500	7,800	13	-	-	-	-	-

“Joint Requesters #14: BAU – Imports” Scenario Summary

- This scenario decreased the imports from the "Joint Requestors’ BAU Reference“ to 2,500 MW

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #14: BAU - Imports	-1,500	1.25	2	2,500	7,800	19	-	-	-	-	-

“Joint Requesters #15: BAU + Max Retirements” Scenario Summary

- This scenario increased the retirements from the "Joint Requestors’ BAU Reference“ to 5,400 MW

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #15: BAU + Max Retirements	-5,400	1.25	2	3,500	7,800	27	208	76	51	10	5

"Joint Requesters #16: BAU + Compressor Outage" Scenario Summary

- This scenario modified the "Joint Requestors' BAU Reference" to reflect a compressor outage, 3 dual-fuel tank refills, and increased the LNG Cap to 1.50 Bcf/d

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1: BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #16: BAU + Compressor Outage	-1,500	1.5	3	3,500	7,800	37	55	11	7	-	-

SCENARIOS BASED ON ISO'S ANALYSIS

These scenarios reflect changes to inputs to the ISO's 23 scenarios and requests for additional scenarios

"AVANGRID" & "BP Energy Scenario #24" Scenario Summary

- These scenarios added 0.50 Bcf/d gas pipeline infrastructure to different ISO scenarios

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Avangrid & BP Energy High Boundary + 0.50 Bcf/d	-1,500	1.25	3	3,500	8,000	11	-	-	-	-	-
Avangrid & BP Energy More Renewables + 0.50 Bcf/d	-1,500	1	2	3,500	8,000	17	-	-	-	-	-
Avangrid & BP Energy More Imports + 0.50 Bcf/d	-1,500	1	2	3,000	6,600	21	-	-	-	-	-
Avangrid & BP Energy More Duel-Fuel Replenishments + 0.50 Bcf/d	-1,500	1	3	2,500	6,600	24	-	-	-	-	-
Avangrid & BP Energy More LNG + 0.50 Bcf/d	-1,500	1.25	2	2,500	6,600	18	-	-	-	-	-
Avangrid & BP Energy Reference + 0.50 Bcf/d	-1,500	1	2	2,500	6,600	24	2	-	-	-	-
Avangrid & BP Energy More Retirements + 0.50 Bcf/d	-4,500	1	2	2,500	6,600	24	41	13	5	1	1

"AVANGRID" & "BP Energy Scenario #24" Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Avangrid & BP Energy Less LNG + 0.50 Bcf/d	-1,500	0.75	2	2,500	6,600	30	40	10	6	-	-
Avangrid & BP Energy Less Duel-Fuel Replenishments+ 0.50 Bcf/d	-1,500	1	1	2,500	6,600	24	31	7	3	-	-
Avangrid & BP Energy Less Imports + 0.50 Bcf/d	-1,500	1	2	2,000	6,600	24	8	-	-	-	-
Avangrid & BP Energy Low Boundary + 0.50 Bcf/d	-4,500	0.75	1	2,000	6,600	32	460	338	285	140	13

"ENGIE" Scenario Summary

- These scenarios added various amounts to the LNG Cap to different ISO scenarios

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
ENGIE07 Low LNG @ 0.94 Bcf/d	-1,500	0.94	2	2,500	6,600	36	207	102	72	22	6
ENGIE 02 and 05 More LNG @2.54 Bcf/d	-1,500	2.54	2	2,500	6,600	-	-	-	-	-	-
ENGIE14 Millstone Nuclear Outage Ref @ 2.11 Bcf/d	-1,500	2.11	3	2,500	6,600	19	-	-	-	-	-
ENGIE14 Millstone Nuclear Outage Max @ 2.54 Bcf/d	-5,400	2.54	3	3,500	9,500	1	-	-	-	-	-
ENGIE 13 Compressor Outage Ref @ 2.11 Bcf/d	-1,500	2.11	3	2,500	6,600	39	106	40	26	3	3
ENGIE 13 Compressor Outage Max @ 2.54 Bcf/d	-5,400	2.54	3	3,500	9,500	23	7	2	1	-	-

"ENGIE" Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
ENGIE 12 Distrigas LNG Outage Ref @ 2.11 Bcf/d	-1,500	2.11	3	2,500	6,600	18	-	-	-	-	-
ENGIE 12 Distrigas LNG Outage Max @ 2.11 Bcf/d	-5,400	2.11	3	3,500	9,500	7	-	-	-	-	-
ENGIE 15 Canaport LNG Outage Ref @ 0.91 Bcf/d	-1,500	0.91	3	2,500	6,600	36	106	40	26	3	3
ENGIE 15 Canaport LNG Outage Max @ 1.54 Bcf/d	-5,400	1.54	3	3,500	9,500	21	7	2	1	-	-

"Environmental Defense Fund" Scenario Summary

- These scenarios either adjusted the LNG Cap, included 0.7% LDC growth, or added 0.40 Bcf/d gas pipeline infrastructure to different ISO scenarios

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
EDF Reference LNG Cap @ 1.25 Bcf/d	-1,500	1.25	2	2,500	6,600	32	40	9	6	-	-
EDF More LNG LNG Cap @ 1.50 Bcf/d	-1,500	1.5	2	2,500	6,600	24	2	-	-	-	-
EDF High Boundary 0.7% LDC Growth	-1,500	1.25	3	3,500	8,000	14	-	-	-	-	-
EDF More Renewables 0.7% LDC Growth	-1,500	1	2	3,500	8,000	20	-	-	-	-	-
EDF More Imports 0.7% LDC Growth	-1,500	1	2	3,000	6,600	24	2	-	-	-	-
EDF More Dual-Fuel Replenishments 0.7% LDC Growth	-1,500	1	3	2,500	6,600	27	1	-	-	-	-
EDF More LNG 0.7% LDC Growth	-1,500	1.25	2	2,500	6,600	21	-	-	-	-	-
EDF Reference 0.7% LDC Growth	-1,500	1	2	2,500	6,600	27	10	1	-	-	-

“Environmental Defense Fund” Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
EDF More retirements 0.7% LDC Growth	-4,500	1	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 Replenishments 0.7% LDC Growth	-1,500	1	1	2,500	6,600	27	78	23	17	2	1
EDF Less Imports 0.7% LDC Growth	-1,500	1	2	2,000	6,600	31	25	7	2	-	-
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/ High Renewables/ Higher Retirements 0.7% LDC Growth	-4,000	0.75	2	3,500	8,000	23	71	18	12	2	1

“Environmental Defense Fund” Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
EDF High LNG/ High Renewables/ Higher Retirements 0.7% LDC Growth	-4,000	1.25	2	3,500	8,000	14	-	-	-	-	-
EDF High Renewables/ High Retirements 0.7% LDC Growth	-3,000	1	2	3,500	8,000	20	-	-	-	-	-
EDF Max Renewables/ Max Retirements 0.7% LDC Growth	-5,400	1	2	3,500	9,500	18	6	2	-	-	-
EDF Millstone Nuclear Outage Ref 0.7% LDC Growth	-1,500	1	3	2,500	6,600	36	48	16	6	1	1
EDF Millstone Nuclear Outage Max 0.7% LDC Growth	-5,400	1	3	3,500	9,500	24	92	28	15	2	1
EDF Compressor Outage Ref 0.7% LDC Growth	-1,500	1.5	3	2,500	6,600	46	274	136	95	25	10
EDF Compressor Outage Max 0.7% LDC Growth	-5,400	1.5	3	3,500	9,500	37	359	185	128	44	12

"Environmental Defense Fund" Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
EDF Distrigas LNG Outage Ref 0.7% LDC Growth	-1,500	1	3	2,500	6,600	35	33	5	3	-	-
EDF Distrigas LNG Outage Max 0.7% LDC Growth	-5,400	1	3	3,500	9,500	23	50	11	7	1	1
EDF Canaport LNG Outage Ref 0.7% LDC Growth	-1,500	0.65	3	2,500	6,600	36	58	19	8	1	1
EDF Canaport LNG Outage Max 0.7% LDC Growth	-5,400	0.65	3	3,500	9,500	23	90	27	18	3	2

"Environmental Defense Fund" Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
EDF Reference + 0.4 Bcf/d	-1,500	1	2	2,500	6,600	24	9	1	-	-	-
EDF Millstone Outage Max + 0.4 Bcf/d	-5,400	1	3	3,500	9,500	23	86	24	14	2	1
EDF Compressor Outage Max + 0.4 Bcf/d	-5,400	1.5	3	3,500	9,500	36	324	155	117	35	9
EDF - Distrigas LNG Outage Max + 0.4 Bcf/d	-5,400	1	3	3,500	9,500	23	44	10	5	1	1
EDF - Canaport LNG Outage Max + 0.4 Bcf/d	-5,400	0.65	3	3,500	9,500	23	79	26	15	3	2

"Eversource" Scenario Summary

- These scenarios added 1.50 Bcf/d gas pipeline infrastructure to different ISO scenarios

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Eversource High Boundary + 1.50 Bcf/d	-1,500	1.25	3	3,500	8,000	-	-	-	-	-	-
Eversource More Renewables + 1.50 Bcf/d	-1,500	1	2	3,500	8,000	-	-	-	-	-	-
Eversource More Imports + 1.50 Bcf/d	-1,500	1	2	3,000	6,600	-	-	-	-	-	-
Eversource More Dual-Fuel Replenishments + 1.50 Bcf/d	-1,500	1	3	2,500	6,600	-	-	-	-	-	-
Eversource More LNG + 1.50 Bcf/d	-1,500	1.25	2	2,500	6,600	-	-	-	-	-	-
Eversource Reference + 1.50 Bcf/d	-1,500	1	2	2,500	6,600	-	-	-	-	-	-
Eversource More Retirements + 1.50 Bcf/d	-4,500	1	2	2,500	6,600	-	-	-	-	-	-
Eversource Less LNG + 1.50 Bcf/d	-1,500	0.75	2	2,500	6,600	-	-	-	-	-	-

“Eversource” Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Eversource Less Dual-Fuel Replenishments + 1.50 Bcf/d	-1,500	1	1	2,500	6,600	-	-	-	-	-	-
Eversource Less Imports + 1.50 Bcf/d	-1,500	1	2	2,000	6,600	-	-	-	-	-	-
Eversource Low Boundary + 1.50 Bcf/d	-4,500	0.75	1	2,000	6,600	3	-	-	-	-	-
Eversource Low LNG/ High Renewables/ Higher Retirements + 1.50 Bcf/d	-4,000	0.75	2	3,500	8,000	-	-	-	-	-	-
Eversource High LNG/ High Renewables/ Higher Retirements + 1.50 Bcf/d	-4,000	1.25	2	3,500	8,000	-	-	-	-	-	-
Eversource High Renewables/ High Retirements + 1.50 Bcf/d	-3,000	1	2	3,500	8,000	-	-	-	-	-	-

“Eversource” Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Eversource Max Renewables/ Max Retirements + 1.50 Bcf/d	-5,400	1	2	3,500	9,500	-	-	-	-	-	-
Eversource Millstone Nuclear Outage Ref + 1.50 Bcf/d	-1,500	1	3	2,500	6,600	3	-	-	-	-	-
Eversource Millstone Nuclear Outage Max + 1.50 Bcf/d	-5,400	1	3	3,500	9,500	-	-	-	-	-	-
Eversource Compressor Outage Ref + 1.50 Bcf/d	-1,500	1.5	3	2,500	6,600	18	-	-	-	-	-
Eversource Compressor Outage Max + 1.50 Bcf/d	-5,400	1.5	3	3,500	9,500	7	-	-	-	-	-

“Eversource” Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Eversource Distrigas LNG Outage Ref + 1.50 Bcf/d	-1,500	1	3	2,500	6,600	3	-	-	-	-	-
Eversource Distrigas LNG Outage Max + 1.50 Bcf/d	-5,400	1	3	3,500	9,500	-	-	-	-	-	-
Eversource Canaport LNG Outage Ref + 1.50 Bcf/d	-1,500	0.65	3	2,500	6,600	3	-	-	-	-	-
Eversource Canaport LNG Outage Max + 1.50 Bcf/d	-5,400	0.65	3	3,500	9,500	-	-	-	-	-	-
Eversource High Boundary + 1.50 Bcf/d	-1,500	1.25	3	3,500	8,000	-	-	-	-	-	-

“Iroquois” Scenario Summary

- These scenarios changed the capacity loss from 1,200 MDth/day to 430 MDth/day in two of the ISO scenarios

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Iroquois Compressor Outage Ref	-1,500	1.5	3	2,500	6,600	35	46	13	8	1	1
Iroquois Compressor Outage Max	-1,500	1.5	3	3,500	9,500	24	69	21	12	3	2

"National Grid" Scenario Summary

- These scenarios either reduced the natural gas supply, or considered an overlapping outage of natural gas and a nuclear unit

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
NGrid Compressor Outage Ref -1.4 Bcf/d	-1,500	1.5	3	2,500	6,600	50	525	377	319	200	19
NGrid Compressor Outage Max -1.4 Bcf/d	-5,400	1.5	3	3,500	9,500	46	598	398	333	169	25
NGrid Compressor Outage Ref -1.4 Bcf/d – Nuclear Unit Outage	-1,500	1.5	3	2,500	6,600	60	864	709	650	504	36
NGrid Compressor Outage Max -1.4 Bcf/d – Nuclear Unit Outage	-5,400	1.5	3	3,500	9,500	50	907	764	693	485	38

“NESCOE” Scenario Summary

- These scenarios increased the renewables assumption to 8,000 MW and the Imports assumption to 3,500 MW

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
NESCOE More Imports/ Increase Renewables + Increase Imports	-1,500	1	2	3,500	8,000	29	24	6	2	0	0
NESCOE More Dual-Fuel Replenishment w/ Increase Renewables + Increase Imports	-1,500	1	3	3,500	8,000	29	8	1	1	0	0
NESCOE More LNG w/ Increase Renewables + Increase Imports	-1,500	1.25	2	3,500	8,000	23	1	0	0	0	0
NESCOE Reference w/ Increase Renewables + Increase Imports	-1,500	1	2	3,500	8,000	29	24	6	2	0	0
NESCOE More Retirements w/ Increase Renewables + Increase Imports	-4,500	1	2	3,500	8,000	29	186	81	62	13	5

“NESCOE” Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
NESCOE Less LNG w/ Increase Renewables + Increase Imports	-1,500	.75	2	3,500	8,000	35	119	49	30	5	3
NESCOE Less Dual-Fuel Replenishment w/ Increase Renewables + Increase Imports	-1,500	1	1	3,500	8,000	29	125	56	35	7	3
NESCOE Less Imports w/ Increase Renewables + Increase Imports	-4,500	1	2	3,500	8,000	29	24	6	2	0	0
NESCOE Low Boundary w/ Increase Renewables + Increase Imports	-4,500	.75	1	3,500	8,000	35	555	393	343	178	18

“NESCOE” Scenario Summary, cont.

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
NESCOE Millstone Outage Ref w/ Increase Renewables + Increase Imports	-1,500	1	3	3,500	8,000	36	92	30	21	3	2
NESCOE Compressor Outage Ref w/ Increase Renewables + Increase Imports	-1,500	1.5	3	3,500	8,000	45	171	63	47	10	5
NESCOE Distrigas Outage Ref w/ Increase Renewables + Increase Imports	-1,500	1	3	3,500	8,000	36	63	19	11	2	1
NESCOE Canaport Outage Ref w/ Increase Renewables + Increase Imports	-1,500	.65	3	3,500	8,000	36	62	20	7	0	0

“NRG” Scenario Summary

- These scenarios were performed with all oil units in and all oil units out

	INPUTS					TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6–11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
NRG Reference All Oil Units In	-1,500	1	2	2,500	6,600	35	128	55	40	9	5
NRG Reference All Oil Units Out	-5,400	1	2	2,500	6,600	46	874	793	751	599	33

Stakeholder Meeting Schedule

Stakeholder Meetings	Scheduled Project Milestone
January 24, 2018 **Reliability Committee**	Begin discussion of the study inputs and results
February 15, 2018	Written comments due with requested assumptions to the RC Secretary (Marc Lyons)
March 28, 2018 **Reliability Committee**	Reliability Committee to discuss results of any stakeholder assumptions
May 30, 2018 **Reliability Committee/ Markets Committee**	Committees to discuss problem and objectives for next steps
Q2 2018 – Q2 2019	Participants and ISO submit and discuss potential solutions

Questions

APPENDIX C

EPLANATION OF THE COMPARISON OF THE OFSA AND THE JOINT REQUESTERS' SCENARIOS

EPLANATION OF THE COMPARISON OF THE OFSA AND THE JOINT REQUESTERS' SCENARIOS

The results of the Joint Requesters' scenarios can be difficult to interpret and compare to ISO-NE's scenarios. ISO-NE's analysis, by virtue of the simplicity of the outputs, does not provide a clear basis by which to identify the relative contributions of different variables to avoiding emergency operating procedures and load shedding. ISO-NE used the same scale to measure the results of the Joint Requesters' scenarios as its own scenarios: the number of hours of emergency operating procedures that would be required to maintain system reliability. This scale does not adequately capture the impact of the Joint Requesters' variable changes because there is no measurement to show by how many hours a scenario avoided any kind of emergency operating procedures. For example, the Joint Requesters' BAU case results in no hours of emergency operating procedures and no hours of load shedding, but it is not possible to tell by how many hours the BAU case avoided any kind of emergency operating procedures or load shedding.

It is also difficult to understand the degree of impact of the Joint Requesters' additional variable changes such as increased electric EE ("JR #5"), battery storage ("JR #6"), or accelerating renewable generation ("JR #4"). None experience any emergency operating procedure hours or hours of load shedding, but it is impossible to tell by how many hours any of these scenarios avoided any emergency operating procedures.

For the 13 Joint Requesters' scenarios with zero hours of emergency actions, the only way to distinguish the scenarios is by the column labeled "Days of LNG at ≥95% Assumed Cap." ISO-NE uses this figure because it is the point at which ISO-NE begins dispatching oil units to conserve remaining gas supply. For example, comparing the BAU case, and the "BAU + higher LDC gas demand" ("JR #2") scenario, shows that the BAU case only has 13 days where

LNG use is at ≥95% of the assumed cap (1.25 Bcf/d), whereas JR #2 has 23 days where the LNG use is at ≥95% of the assumed cap. Since all the other variables are constant between these two scenarios, the comparison shows that increasing the LDC gas demand increases the number of days where LNG is ≥95% of 1.25 Bcf/d (the assumed cap in this scenario). Because the need to dispatch oil to conserve gas supplies tends to show a shortage of availability of natural gas, JR #2 represents a less "secure" electric grid operating status than the BAU case.

Table 4. Days of LNG at ≥95% of assumed cap comparison JR #1 and JR #2.

	Retirements (MW)	LNG Cap (Bcf/d)	Oil Tank Fills	Imports (MW)	Renewables (MW)	Days of LNG at ≥ 95% of Assumed Cap	OP 4 Hrs.	OP 4 Action 6-11	Hrs. of 10 Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
JR #1 BAU	-1,500	1.25	2	3,500	7,800	13	-	-	-	-	-
JR #2 BAU + Higher LDC	-1,500	1.25	2	3,500	7,800	23	-	-	-	-	-

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