Operational Fuel-Security Analysis

For Discussion

ISO new england

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Highlights: Operational Fuel-Security Analysis

- **Fuel-security risk** – the possibility that power plants won't have or be able to get the fuel they need to run, particularly in winter – is the **foremost challenge to a reliable power grid in New England**.

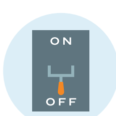
- ISO New England studied **23 possible future resource combinations** during winter 2024/2025 to determine whether enough fuel would be available to meet demand and to understand the operational risks.

- The ISO chose winter 2024/2025 and 23 scenarios to depict a **wide range of possible future power system conditions** in the mid-2020s. Actual power grid conditions could change earlier or later than the 2024/2025 target winter.

- These scenarios, while not a precise prediction of the future system, seek to illustrate the **range of potential risks** that could confront a power system if fuel and energy were constrained during winter.

- The goal is to improve the ISO's and the region's **understanding of these risks** and inform the ISO's subsequent discussions with stakeholders.

- The study assumed that no additional natural gas pipeline capacity to serve generators would be added within the timeframe of this study and instead focused on **five other variables** that are likely to be key factors in power system reliability. Notable findings regarding each variable:

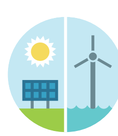


Resource Retirements
The retirements of coal-fired, oil-fired, and nuclear generators – resources with fuel stored on site – will have a significant impact on reliability and magnify the importance of other variables, particularly liquefied natural gas (LNG) supplies.

LNG Availability
Improving generators' advance arrangements for timely winter deliveries of LNG could significantly reduce fuel-security risk, while reduced volumes of this global commodity would raise risk.

Oil Tank Inventories
The availability of oil stored in tanks on site is a key reliability factor and depends on the extent to which natural-gas-fired generators are able to add dual-fuel capability to burn oil, how often they can run on oil, and whether they have oil when needed.

Imported Electricity
Expanding access to electricity from neighboring power systems would help mitigate fuel-security risk but would require investment in transmission infrastructure.



Renewable Resources
Accelerating the growth of renewable resources would enhance fuel security but would not eliminate reliance on LNG. It also would likely lead to more non-gas-fired resource retirements and require transmission investment.

- Energy shortfalls due to inadequate fuel would occur with almost every fuel-mix scenario in winter 2024/2025, requiring frequent use of **emergency actions** to keep power flowing and protect the grid. Emergency actions that would be visible to the public range from requests for energy conservation to load shedding (rolling blackouts affecting blocks of customers).

- The study's findings suggest **six major conclusions:**

  1. **Outages:** The region is vulnerable to the season-long outage of any of several major energy facilities.
  2. **Stored fuels:** Power system reliability is heavily dependent on LNG and electricity imports; more dual-fuel capability is also a key reliability factor, but permitting for construction and emissions is difficult.
  3. **Logistics:** The timely availability of fuel is critical, highlighting the importance of fuel-delivery logistics.
  4. **Risk trends:** All but four scenarios result in fuel shortages requiring load shedding, indicating the trends affecting New England's power system may intensify the region's fuel-security risk.
  5. **Renewables:** More renewable resources can help lessen the region's fuel-security risk but are likely to drive coal- and oil-fired generation retirements, requiring high LNG imports to counteract the loss of stored fuels.
  6. **Positive outcomes:** Higher levels of LNG, imports, and renewables can minimize system stress and maintain reliability; to attain these higher levels, delivery assurances for LNG and electricity imports, as well as transmission expansion, will be needed.

- The ISO will discuss the study with regional stakeholders and determine whether further **operational or market design measures** are needed to address the region's fuel-security risk.

Executive Summary

The health and safety of New England's 14 million residents and the vibrancy of its economy depend on a reliable power supply, and that requires fuel security – that is, a reliable supply of the various fuels used to generate the region's electricity. New England's generation fleet relies primarily on fuels imported from elsewhere in the United States or from overseas to produce power, giving fuel procurement, transportation, and storage a pivotal role in power system operations. This is particularly true during winter when fuel for nearly half the region's generating capacity may become inaccessible due to priority demand for natural gas from the heating sector.

As the operator of the region's six-state power system, ISO New England is required to plan and operate the grid to ensure a reliable supply of electricity. To help fulfill this responsibility, the ISO conducted a fuel-security analysis that evaluated the level of operational risk posed to the power system by a wide range of potential fuel-mix scenarios. The study quantified the risk by calculating whether enough fuel would be available for the system to satisfy consumer electricity demand and to maintain power system reliability throughout an entire winter.

Fuel-security risk*—the possibility that power plants won't have or be able to get the fuel they need to run, particularly in winter—****is the foremost challenge to a reliable power grid in New England.***

Background

On multiple occasions in recent winters, the ISO has had to manage the system with uncertainty about whether power plants could arrange for the fuel – primarily natural gas – needed to run.[1] Because the ISO has no jurisdiction over other industries' various fuel-delivery systems, it has addressed the effects of insufficient fuel supplies on the power system by employing real-time emergency operating procedures and implementing market design changes to incentivize generators to arrange for adequate fuel supplies. The ISO has also worked on improving communication and coordination with natural gas pipeline operators.

The ISO has been able to maintain power system reliability during severe winter conditions without using all its emergency procedures. However, the evolving generation mix is increasingly susceptible to variable and uncertain factors. Natural gas pipeline constraints, the logistics of importing liquefied natural gas (LNG)

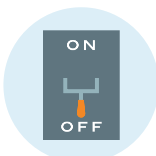
1. **Winter 2003/2004:** ISO New England Internal Market Monitor, *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 "Cold Snap"* (October 12, 2004), https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne_final_report_jan2004_cold_snap.pdf; **Winter 2012/2013:** ISO New England, "Winter Operations Summary: January–February 2013," discussion paper (February 27, 2013), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb__27_draft_for_discussion.pdf; and **Winter 2013/2014:** ISO New England, "Oil inventory was key in maintaining power system reliability through colder-than-normal weather during winter 2013/2014" (ISO Newswire, April 4, 2014), http://isonewswire.com/updates/2014/4/4/oil-inventory-was-key-in-maintaining-power-system-reliabilit.html.

and fuel oil, the impact of New England's weather on the availability and timing of fuel deliveries, and the amount and timing of electricity generated by renewable resources all contribute to a high level of uncertainty for ISO system operations.

In fall 2016, ISO New England initiated a study to better understand any potential future impacts of fuel-security risk. The study estimated the operational impacts of possible fuel-mix scenarios so that the ISO and the region can assess the level of risk and plan appropriate mitigation, if needed. Economic effects were not measured.

The Study

While actual power grid conditions could change earlier or later than the target winter, the ISO modeled a wide range of resource combinations that might be possible by **winter 2024/2025,** considering **five key fuel variables:**

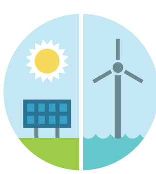


The retirements of coal- and oil-fired generators

The availability of LNG

Dual-fuel generators' oil tank inventories (i.e., how often on-site fuel tanks can be filled at dual-fuel generators that can switch between natural gas and oil)

Electricity imports



The addition of renewable resources

This study did not assess the impacts of adding natural gas pipeline capacity to serve generators within the timeframe of this study. The study incorporated the demand-reducing effects of projected energy-efficiency measures and distributed solar power.

The study includes **23 scenarios:**

- **1 reference case** 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.
- **8 single-variable cases** increase or decrease the level of just one key variable to assess its relative impact in each case.
- **2 boundary cases** illustrate what would happen if either all the favorable or all the unfavorable variables were realized simultaneously.
- **4 combination cases** combine the five key variables to represent future resource portfolios that could develop and their effects on fuel security.
- **8 outage cases** illustrate the effects of a winter-long outage at major energy facilities in the region.

The operational impact was measured in 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.

Key Takeaways

In almost all future resource combinations, the power system was unable to meet electricity demand and maintain reliability without some degree of emergency actions. Some key takeaways:

- **Load shedding (19 cases)** – Among the combination cases, all but the most optimistic case resulted in load shedding, also known as rolling blackouts or controlled outages that disconnect blocks of customers sequentially. Load shedding is implemented as a last resort to protect the grid. All but three of the single-variable cases resulted in some degree of load shedding.
- **Public requests for energy conservation (22 cases)** – All but one of the cases led to the use of emergency actions that include public requests for energy conservation.
- **No emergency actions (1 case)** – The favorable boundary case represented a best-case resource combination that was fully able to meet demand without special actions. However, it did not reflect the increase in retirements of oil-fired generators that would be expected to accompany increased levels of the other four variables: LNG, oil inventories for dual-fuel generators, imports, and renewables.
- **Vulnerabilities** – The single-variable cases revealed the region's vulnerability to resource retirements and the availability of LNG. These cases also show that while increasing the amount of renewables would enhance fuel security, it would not eliminate reliance on imported LNG.

The study results are not precise predictions. *Rather, they help compare different possible future fuel scenarios so that the ISO and the region can discuss a level of tolerable risk and plan appropriate mitigation.*

- **Outages –** All the outage cases resulted in many hours of load shedding, particularly the season-long loss of a nuclear plant or pipeline compressor. Even significant increases in LNG, dual-fuel capability, and renewables would not eliminate the risk. While outages of shorter duration were not studied, it's likely that an outage of any duration at any of these facilities would create significant system stress.

The results are derived from the 23 scenarios analyzed; not every possible future resource combination has been modeled in this study. The study results should not be interpreted as precise measurements. Instead, the number of hours of emergency actions for each fuel scenario should be interpreted as an indicator of system stress.

Taken together, the study results suggest that **New England could be headed for significant levels of emergency actions**, particularly during major fuel or resource outages. Harder to measure are the risks to the region from brief, high-demand cold spells, which present particular logistical challenges for fuel procurement and transportation.

Next Steps

The ISO will discuss the results of this operational fuel-security analysis with stakeholders, regulators, and policymakers throughout 2018. A key question to be addressed will be the level of fuel-security risk the ISO, the region, and its policymakers and regulators would be willing to tolerate. A primary consideration for the ISO is its responsibility, as a regional reliability coordinator, to operate the New England power system in a way that maintains the reliability of the entire Eastern Interconnection.[2]

2. The Eastern Interconnection is one of two major alternating-current power grids in North America covering from central Canada east to the Atlantic coast (excluding Québec), south to Florida, and west to the foot of the Rocky Mountains (excluding most of Texas). During normal system conditions, all the smaller power systems in this area are electrically interconnected and operate at a synchronized frequency of 60 Hz average. The Eastern Interconnection is tied to the Western Interconnection, the Texas Interconnection, and the Québec Interconnection generally through numerous high-voltage direct-current transmission lines.

Background:

The Changing Grid and New England's Fuel-Supply, Infrastructure, and Logistical Challenges

A reliable power system requires a reliable supply of the fuels used to generate electricity. Because New England depends primarily on imported fuels to produce power, fuel security—or the assurance that power plants will have or be able to get the fuel they need, when they need it—is critical for the region's power system reliability.

Fuel security is a growing concern in New England. The regional power system is increasingly dependent on natural gas for power generation; the capacity of the region's natural gas infrastructure is not always adequate to deliver all the gas needed for both heating and power generation during winter; and natural gas is the fuel of choice for a large segment of new power plant proposals. The region's coal, oil, and nuclear power plants, which have fuel stored on site and are essential for reliability when natural gas is in short supply, are retiring. Further, the region has limited dual-fuel generating capability—that is, generators that can use either natural gas or oil—and emissions restrictions on burning oil are tightening.[3]

A dependable fuel supply requires a fuel-delivery system that has the appropriate physical capability to transport all the fuel needed, the contractual arrangements secured in advance to ensure timely deliveries, and power plants that have fuel storage on site. In New England, fuels need to be delivered and storage must be available throughout the winter months.

The region's fuel-security risks have been evident to ISO New England since a 2004 cold snap.[4] The ISO, a private, not-for-profit company independent from all companies doing business in the region's electricity marketplace, operates the six-state power grid around the clock. The ISO is responsible for maintaining the precise balance of supply and demand required to keep the lights on in New England and avoid cascading power system infrastructure outages that can trigger a widespread blackout.

On multiple occasions in recent winters, the ISO's system operators have been confronted with the challenges that arise when power plants can't get fuel. Because the reliability of New England's power system was maintained throughout these events, the region's electricity consumers have been shielded from this growing risk, apart from severe winter price spikes that eventually show up in retail rates.[5]

3. The region's current fleet of dual-fuel capable power plants totals about 8,750 megawatts (MW), but this includes about 2,200 MW from older, oil-fired power plants that rarely run on natural gas and are at risk of retirement.

4. During a January 2004 cold snap, more than 6,000 MW of natural-gas-fired generation was unavailable, much of it due to lack of fuel. ISO New England Internal Market Monitor, *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 'Cold Snap'* (October 12, 2004), https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne_final_report_jan2004_cold_snap.pdf.

5. The total value of the wholesale energy market for the three months of winter 2013/2014 was about $5.05 billion. By comparison, the value of energy market transactions in 2016—the year with the lowest wholesale power prices since 2003—was $4.1 billion for the entire 12 months. Refer to the ISO's "Oil inventory was key in maintaining power system reliability through colder-than-normal weather during winter 2013/2014" (ISO Newswire, April 4, 2014), http://isonewswire.com/updates/2014/4/4/oil-inventory-was-key-in-maintaining-power-system-reliabilit.html.

The Changing Grid

These real-world challenges are likely to intensify as a result of several interconnected trends that are rapidly changing the makeup of New England's power system:

- Increasing use of natural gas generation as the region shifts away from coal- and oil-fired power plants
- Retirements of coal- and oil-fired power plants and nuclear plants
- Growth of renewable resources, propelled by state initiatives
- Growth of resources that reduce consumer demand from the regional grid: energy-efficiency (EE) measures, such as energy-saving lightbulbs, and "behind-the-meter" (BTM) solar panels installed at homes and businesses on the distribution systems managed by local utilities

The Dash to Gas

The two most significant of these trends are the increasing use of natural gas and the retirement of power plants that use fuels other than natural gas. By far the biggest factor is the "dash to gas." Two decades ago, the regional power system derived most of its electricity from generators with fuel stored on site: coal, oil, and nuclear. Today, coal-fired, oil-fired, and nuclear power plants are still a significant portion of the region's generation fleet, but natural-gas-fired generators make up nearly half the fleet and use "just-in-time" fuel deliveries.

In 2000, oil- and coal-fired power plants produced 40% of the electricity generated in New England, while natural gas produced 15%. Starting in 2009, natural gas prices plummeted with the boom in domestic shale gas production. Because ISO New England dispatches the lowest-cost resources first to meet demand, natural-gas-fired generators are used most often. By 2016, natural gas generation had risen to nearly half the electricity produced in New England (49%), while coal and oil dropped to 3% of annual electricity generation, although they still make up nearly 30% of the region's total generating capacity.

While the use of natural gas for both heating and power generation is growing, the natural gas supply infrastructure is not expanding at the same pace, resulting in natural gas supply constraints in winter.[6] Given the region's current and growing reliance on natural gas, limitations on the region's natural gas delivery infrastructure are the most significant component of New England's fuel-security risk.

When pipeline supply constraints occur, all or almost all the available natural gas goes to heating customers. When natural-gas-fired power plants haven't been able to procure the fuel they need to run during recent winters, most of the region's power has come from coal, oil, and nuclear power plants – generators with readily available fuel stored on site – and imports from neighboring power systems with adequate natural gas infrastructure or energy storage in the form of hydroelectric facilities.[7]

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6. ICF International, *New England LDC Gas Demand Forecast Through 2030*, presentation (October 3, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-ldc-demand-forecast-03-oct-2016.pdf.

7. While pumped hydroelectric facilities are considered to have "stored fuel," in this report the term applies to coal, oil, and nuclear power plants. New England has three pumped-storage hydro facilities that store energy in the form of water in large ponds; when released through turbines, this stored water can provide critical reliability support by generating more than 1,800 MW of energy within 10 minutes, and for up to seven hours. The loss of pumped storage was not studied in this analysis, but pumped storage was included in the dispatch of resources to meet demand.

Retirements of Coal, Oil, and Nuclear Power Plants

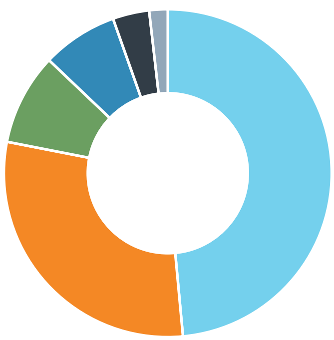
The low average annual output from generators using oil or coal masks the major contributions of these aging generators during peak winter and summer days when they may be contributing as much as a third, sometimes more, of the region's power (see Figure 1). These are typically days when summer demand peaks or during winter when generators can't access enough natural gas or the price of natural gas spikes.

Generators with Stored Fuels Are Key Contributors to Reliability on Cold Days

During winter 2014/2015, combined contributions from oil and coal peaked at over 40% of regional generation on February 24, 2015. Annually, however, these fuels together produced only 6% of New England's generation. Nuclear power, another major non-gas-fired generation source, also made a significant contribution on February 24, 2015. Natural-gas-fired generation, meanwhile, dropped to just 17% for the day, despite providing 49% annually.

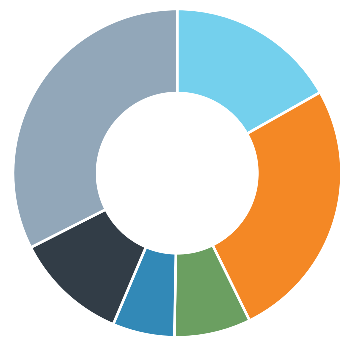
Figure 1: 2015 Annual Fuel Mix Compared with Day of Highest Coal and Oil Generation in 2015

2015 Annual Fuel Mix



2015 Annual	Fuel	February 24, 2015
49%	Natural Gas	17%
30%	Nuclear	26%
9%	Renewables	8%
7%	Hydro	6%
4%	Coal	11%
2%	Oil	32%

February 24, 2015
19°F High



Source: ISO New England, *2000–2015 Net Energy and Peak Load by Source* and *Daily Generation by Fuel Type 2015*

In 2012, as part of its Strategic Planning Initiative, the ISO identified about 8,300 megawatts (MW) of coal- and oil-fired generators at risk of retirement due to age and economic headwinds.[8] Between 2013 and 2019, nearly 3,000 MW of coal- and oil-fired generation have retired or will retire, leaving about 5,400 MW available but at risk of retirement.

Nuclear power plants represent about 13% of New England's generating fleet but produced 31% of the region's electricity in 2016. Nuclear plants are also retiring in New England and across the country; owners have cited low wholesale electricity prices stemming from low-priced natural gas as the key driver. Vermont Yankee retired at the end of 2014, and Pilgrim will retire by 2019, removing about 1,300 MW of baseload power from New England's fleet.

8. ISO New England, "Strategic Planning Initiative Key Project," webpage (2017), https://www.iso-ne.com/committees/key-projects/implemented/strategic-planning-initiative, and *Strategic Transmission Analysis: Generation at Risk of Retirement*, Planning Advisory Committee (PAC) presentation (December 18, 2012), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/dec132012/retirements_redacted.pdf.

In total, the recent and impending retirements of coal-fired, oil-fired, and nuclear power plants add up to the departure by June 2021 of 4,600 MW of generators that use fuels other than natural gas.[9] That's more than 10% of the region's total installed power plant capacity.

The retirements of these aging generators may accelerate as more renewable resources are added to the regional power system. Renewable resources often have the benefit of state and federal financial incentives, as well as long-term contracts sponsored by states seeking to expand their clean energy portfolios. As such, these renewable resources have low costs and can bring down prices in both the energy and capacity markets. These lower prices may drive out coal- and oil-fired generators and nuclear plants dependent on these revenues.

Growth of Renewable Resources

New England's fleet of renewable resources, powered by water, sun, wind, biomass, and trash, is still small, but wind and solar resources are growing rapidly. The region now has 25 onshore wind farms with more than 1,200 MW of nameplate capacity, up from 375 MW just six years ago, in 2011.[10] State and federal production credits and tax incentives have encouraged this growth.

Additional onshore wind facilities face challenges in development. Most are proposed for construction in remote areas of northern New England where the transmission system was sized to serve the sparse local population, not to carry large amounts of generation. Building the transmission needed to deliver the proposed wind energy to southern New England load centers has proven to be challenging for developers and the region.

The nation's first offshore wind farm, with a 30 MW nameplate capacity, came on line in 2016 off the coast of Block Island, and several companies are competing to build much larger wind farms off the coast of Massachusetts and Rhode Island.

New England has a long history of hydroelectric generation, with hundreds of small dams and several larger facilities. Pumped storage is also a key resource in the region. New England imports about 17% of its energy annually, with much of that coming from Hydro-Québec, which gets almost all its energy from hydro facilities.

The New England states have goals and requirements for clean energy that serve as a major driver of the growth of renewable resources in the region. Massachusetts, Connecticut, and Rhode Island issued a request for clean energy proposals in 2016 and have selected proposals for 460 MW.[11] Massachusetts is also implementing legislation that calls for the equivalent of about 1,200 MW of clean energy, including hydro from Canada, by 2022.[12] The request for proposals (RFP) for this initiative drew a robust response. The legislation also calls for 1,600 MW of offshore wind by 2027.

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9. The retirements of coal- and oil-fired generators include Salem Harbor (749 MW, shut down in 2011 and 2014), Norwalk Harbor (342 MW, shut down in 2013), Brayton Point (1,535 MW, retired 2017), Mount Tom (143 MW, shut down in 2014), and Bridgeport Harbor 3 (383 MW by June 2021). The nuclear retirements include Vermont Yankee (604 MW, retired 2014) and Pilgrim (677 MW by June 2019). The 4,600 MW also includes a number of smaller generators.

10. *Nameplate* refers to the maximum electricity a resource is rated capable of providing. Most resources' actual output is a smaller percentage of maximum due to outages, and most renewable resources have a lower actual output percentage due to the variability of weather. Actual production from solar photovoltaics (PV) is expected to be about 8% of nameplate (shorter days, more cloud cover in winter), while the output from onshore wind is expected at about 48% and offshore wind at about 53% of nameplate capability.

11. *New England Clean Energy RFP* (https://cleanenergyrfp.com/). In November 2015, Massachusetts, Connecticut and Rhode Island, issued an RFP to deliver additional supplies of renewable energy and large-scale hydropower to the New England power system. The three states collectively selected projects representing about 460 MW of clean energy for the New England market. None of the projects included associated transmission to deliver the clean energy supplies to New England load centers. The selection of the winning bids will not be final until contract negotiations and regulatory approvals are complete.

12. Massachusetts Gov. Charlie Baker, "Governor Baker Signs Comprehensive Energy Diversity Legislation," press release (August 8, 2016), http://www.mass.gov/governor/press-office/press-releases/fy2017/governor-baker-signs-comprehensive-energy-diversity-law.html. In Massachusetts, *An Act to Promote Energy Diversity* (H. 4568), requires Massachusetts electricity distribution companies to procure 1,600 MW of cost-effective offshore wind energy by 2027 and about 1,200 MW of clean energy generation – baseload hydropower, onshore wind, and solar supported by hydropower, standalone onshore wind, solar, or other Class I renewable resources by 2022. (https://malegislature.gov/Laws/SessionLaws/Acts/2016/Chapter188)

The queue of new generation projects seeking to interconnect to the high-voltage power grid operated by the ISO totaled about 13,500 MW as of December 1, 2017. Proposed wind farms make up just over half the proposals, or about 7,300 MW. The queue also includes 1,000 MW of proposed solar (8% of the total) and 400 MW of battery storage (3% of the total). Not all these projects will be constructed; historically, about 68% of the megawatts proposed are never built.

The vast majority of solar photovoltaic (PV) resources in New England are behind the meter, on the distribution system managed by local electric power utilities. A handful of large solar farms are participating in the regional wholesale markets totaling about 50 MW (nameplate); the largest is about 16 MW.

Advanced storage technologies hold promise as resources that can support reliability and the technology is progressing, but cost-effective, advanced energy storage is not yet available at a scale that can ensure reliability on a 35,000-MW power system. Currently, there are about 20 MW of utility-scale battery storage connected to the regional grid; it is unclear at this stage how higher levels of battery storage will affect the frequency and duration of energy shortages.

Growth of Energy-Efficiency Measures and Behind-the-Meter Solar

The New England states are national leaders in energy efficiency, collectively spending more than $1 billion annually to install energy-efficiency measures in homes and businesses.[13] The efforts are paying off, according to ISO New England's annual energy-efficiency forecast.[14] Total annual energy consumption in New England is tapering off, while winter peak demand is forecasted to decline very slightly from 2017 to 2026.

Behind-the-meter solar photovoltaic installations are also fueling reductions in energy consumption and peak demand. Just five years ago, at the end of 2012, New England had about 250 MW of BTM solar PV installed. At the end of 2016, the number had increased to 1,900 MW, and the ISO's PV forecast projects that by 2024, the region will have 4,400 MW of solar PV (and 4,700 MW by 2026).[15] All this new PV will be installed at homes and businesses on the distribution system, serving to reduce demand for power from the regional power grid. State incentives, particularly in Massachusetts, are helping drive this growth.

By lowering demand from the regional grid, these resources can have the effect of lowering prices as well, diminishing energy and capacity revenues and creating greater financial pressure on more costly resources.

Logistical Uncertainties: Fuel Deliveries and Weather

The region still needs power plants with fuel stored on site, but if they can't get the fuel, they can't run. The uncertainty surrounding New England's fuel-security risk is compounded by an unquantifiable X factor: fuel-delivery logistics.

Fuel-security risks may be more acute in New England than in most other regions because New England is "at the end of the pipeline" when it comes to the fuels used most often to generate the region's power. New England has no indigenous fossil fuels and therefore, fuels must be delivered by ship, truck, pipeline, or barge from distant places.

13. American Council for an Energy-Efficient Economy, "California Golden Again on Energy Efficiency, Regains #1-State Spot in Tie with 6-Time Winner Massachusetts," press release (September 27, 2016), http://aceee.org/press/2016/09/california-golden-again-energy.

14. ISO New England, "Final Energy Efficiency Forecast: 2021-2026" (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/final_eef_2017_v2.pdf.

15. ISO New England, "2017 Final PV Forecast" (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/2017_solar_forecast_details_final.pdf.

The natural gas pipeline system within New England is relatively small, and its access to the rest of the North American pipeline network is limited. In regions with a more robust pipeline network, a failure of a single point on the pipeline system typically can be contained to a local area and routed around, but such an outage in New England will likely create significant impacts.

Limitations or constraints on the fuel-supply chain are not unusual, particularly during bad weather. Winter storms can impede deliveries from liquefied natural gas (LNG) tankers, oil barges, and oil tanker trucks. Low temperatures can increase heating demand for natural gas, oil, and LNG, leaving less for power plants.

Renewable resources can help reduce the demand for energy and the fuels that generate it, but the output of wind and solar facilities depends on the weather and time of day. For example, solar panels can reduce the consumption of natural gas and oil during sunny winter days, so more oil and gas are available later to generate electricity to meet the daily winter peak demand. Solar energy can't help directly with the winter peak, however, because demand peaks after the sun has set.

The timing of fuel consumption and of fuel replenishment can be significant as well. In December, the weather is typically milder. As winter progresses in time and intensity, generators' oil and LNG inventories are depleted and tanks must be refilled rapidly.

Some typical logistical concerns for each fuel are outlined below:

- **Natural gas**
  - **Pipeline gas**. New England receives natural gas via five pipelines from the west through New York State, and from Canada in the north.

    Most of the region's pipeline gas is delivered through New York, where natural-gas-fired generators have the first opportunity to withdraw any surplus natural gas that is not already committed to the gas utilities.[16] Developers are proposing to build more new natural-gas-fired generation in eastern New York. Indian Point Energy Center, a nearly 2,100 MW nuclear station near New York City, has announced it will retire by 2021, which may increase demand for natural gas from generators in New York and could result in reduced supply to New England generators during periods of peak demand.[17] This study does not attempt to quantify these effects, however. Further, construction of additional pipeline capacity in New York will likely prove difficult.[18] Some natural gas is delivered to New England via pipeline from eastern Canadian natural gas fields off Nova Scotia, but most of this supply will be gone by 2020. The primary sources of natural gas for the Canadian Maritimes will become Canaport, a 10 billion cubic feet (Bcf) LNG import, storage, and regasification facility in New Brunswick, and the Maritimes and Northeast (M&N) pipeline. When it is serving Maritimes heating

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16. ICF International, *Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies* (November 18, 2013), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11_18_2013.pdf. Eastern Interconnection Planning Collaborative (EIPC), *Gas-Electric System Interface Study Target 2 Report: Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems* (March 9, 2015), p. 149, http://nebula.wsimg.com/c1a27fe57283e35da35df90f71a63f7a?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1.

17. New York ISO, *Power Trends: New York's Evolving Electric Grid, 2017* (2017), p. 35, https://www.google.com/url?q=http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2017_Power_Trends.pdf&sa=U&ved=0ahUKEwicr-KkrO7VAhWCwFQKHSc1C1QQFggEMAA&client=internal-uds-cse&usg=AFQjCNG4pCnCu_ZyHocx1sQurUb0HzeJ5A. Patrick McGeehan, "Cuomo Confirms Deal to Close Indian Point Nuclear Plant" (New York Times [NYT], January 9, 2017), https://www.nytimes.com/2017/01/09/nyregion/cuomo-indian-point-nuclear-plant.html.

18. New York ISO, *Power Trends, 2017*, pp. 36–37.

demand, the M&N will be transporting gas from New York or Québec, through New England, to the Maritimes. The result could be less pipeline gas for New England.[19]

- **Liquefied natural gas.** LNG can be an important complement to pipeline gas. It is imported to New England from overseas by ocean-going tankers, typically from Trinidad and Tobago. Most cargoes of LNG need to be contracted and scheduled for months before winter begins; once contracted, the LNG won't arrive for at least five days.

  LNG availability can also be affected by global weather or political events.[20] Ocean-going tankers can have difficulty offloading their cargoes at offshore LNG buoys or in ports during winter storms. Cold snaps can result in a sudden drawdown of stored LNG, and the rapid depletion of LNG combined with the region's limited storage facilities can challenge the region's fuel-supply chain, particularly if outages increase the need for LNG.

- **Oil.** The region's remaining oil-fired power plants get their fuel delivered by oil pipeline, barges, or tanker trucks – but as more and more oil-fired power plants have retired, the delivery supply chain has withered as well. Fewer oil barges and tanker trucks are located in New England. Oil-fired generators may start the winter with full tanks of oil stored on site, but a generator that depletes its oil inventory during a cold snap may not be able to refill its tank promptly if a winter storm prevents tanker trucks from traveling.

  In winter, oil delivery trucks may be occupied delivering fuel to heating oil dealers and unavailable for power plant deliveries, or federal restrictions on how many hours drivers can drive may delay deliveries. Rivers may freeze, preventing barges from bringing fuel to generators.

  In addition to potential fuel-delivery concerns, environmental restrictions limit how often many power plants can generate electricity using oil. Many of the region's dual-fuel power plants are currently limited to running no more than approximately 30 days per year on oil, and Massachusetts is implementing tighter air emissions regulations.

Natural Gas Delivery Challenges: Infrastructure Constraints and Contracts

The natural gas system was sized and built to meet the peak demand needs of the local natural gas utilities (also called local distribution companies, or LDCs) serving heating customers. The natural gas utilities contracted for the pipeline capacity, so they have first priority for gas delivery.

On many days, pipeline capacity is sufficient for both the local gas utilities and the natural-gas-fired power plants, but during the coldest weeks of the year, this natural gas delivery infrastructure can't meet all the demand for natural gas for both home heating and power generation. As a result, natural-gas-fired power plants – which typically buy pipeline capacity released by local gas utilities on the secondary market – may not be able to access natural gas.

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19. "Nova Scotia's Deep Panuke natural gas projects drying up" (*The Chronicle Herald*, May 30, 2017), http://thechronicleherald.ca/business/1473337-nova-scotias-deep-panuke-natural-gas-projects-drying-up.

20. Erin Ailworth, "Unrest in Yemen may result in local LNG shortage" (*Boston Globe*, May 5, 2012), http://www.bostonglobe.com/business/2012/05/04/electric-power-plants-threatened-attacks-gas-pipelines-yemen/48P2O2KqNm9sEa2P6dr6lM/story.html.

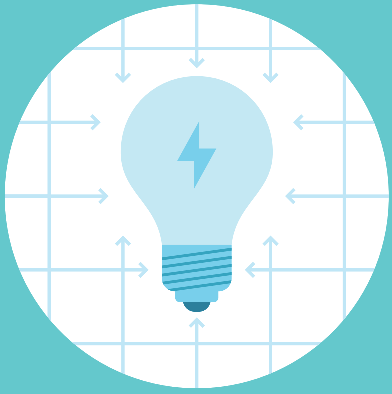
Contracting with pipelines for some level of firm natural gas delivery could solve this problem if the pipeline system expanded to accommodate the increased contracted demand. However, contracting for firm pipeline capacity is costly and requires a long-term commitment. This has been a deterrent for natural gas power plant owners, who have short- to medium-term financial horizons and are a diverse group with diverse market interests.

Contracting for LNG could also help if these contracts are executed before winter arrives. Typically, the ocean-going tankers that transport LNG are committed in the fall for winter delivery, so a sudden or unanticipated need to replenish LNG supplies may go unmet during an unexpectedly bad winter. In addition, as heating demand for natural gas grows, local gas utilities are likely to begin contracting for more of the region's limited LNG storage capacity, leaving even less for natural-gas-fired power plants.

Further, contracting for oil and LNG deliveries can be difficult during winter when other types of customers (e.g., heating, industrial customers) are also seeking urgent deliveries. When power plants don't sign contracts for pipeline gas or LNG, nor enter the winter with full oil tanks, deliveries of oil or LNG when needed cannot be guaranteed.

The retirements of power plants with stored fuel, tightening emissions restrictions, and the reliance on a fuel that may not be available when needed most are all challenging New England's power system. Logistical and time- and weather-dependent fuel-delivery uncertainties introduce additional potential for fuel-security risks that could degrade the reliability of the regional power system.

Operational Fuel-Security Analysis



The shift away from generators with on-site fuel to natural-gas-fired generators relying on "just-in-time" fuel delivery has exposed the limitations of New England's existing fuel infrastructure and has heightened the region's fuel-security risks.

As the system continues to change, it is incumbent on ISO New England, as the reliability coordinator for New England's six-state power grid, to assess the potential operational impacts these risks may pose in the near future.[21]

Study Description

The ISO launched this operational analysis to quantify the region's future fuel-security risk—that there may be times when sufficient fuel is not available for power plants to generate all the electricity required to meet consumer demand and maintain power system reliability during the entire winter of 2024/2025.

The study determined whether or how often the region would run short of natural gas and oil during an entire 90-day winter and calculated how often the resulting energy shortfalls would require the ISO to employ emergency actions, up to and including rolling blackouts.

Resources and Key Variables

The study developed a wide range of hypothetical scenarios of a regional power system composed of different resource combinations, incorporating the same types of resources and fuels as those in New England's fleet today:

- Natural-gas-fired generators
- Oil-fired generators
- Dual-fuel generation (power plants that can use natural gas or oil stored on site; most use natural gas as their primary fuel and oil as their backup fuel)
- Renewable resources, including on- and offshore wind, solar, biomass, and behind-the-meter solar photovoltaics
- Energy-efficiency measures
- Nuclear power plants
- Hydro generation
- Pumped-storage generation
- Imports

21. North American Electric Reliability Corp, "Reliability Coordinators," webpage (2016), http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx.

The exception was the region's remaining coal-fired power plants, which were assumed to be retired by 2024.

Five key factors affecting power system operations were the variables in each scenario:

- **Retirements** of generators that use fuels other than natural gas (coal and oil)
- **Imports** of electricity over transmission lines from neighboring power systems in New York and Canada
- Level of **renewable resources** on the system
- Level of **LNG injections** into the region's natural gas delivery and storage infrastructure
- **Dual-fuel generators' oil tank inventories** – that is, how often the oil tanks on site at dual-fuel power plants are filled and refilled throughout a 90-day winter

The analysis modeled 23 possible future resource-mix combinations, including four high-impact outages of key energy facilities, during December, January, and February, of winter 2024/2025.[22] The study assessed each scenario's physical capabilities to meet demand and required reserve levels by calculating the amount of fuel needed to generate all the electricity required. The study then compared the amount of fuel needed with the actual level of fuel – wind, sun, hydro, other renewables, nuclear, imported electricity, natural gas delivered via pipeline, and oil and LNG stored in tanks – the region's fuel infrastructure could deliver to each hypothetical resource mix.

The Need for Emergency Actions

The study determined whether or how often the region would run short of fuel and calculated how often the resulting energy shortfalls would require emergency actions, up to and including rolling blackouts. For each scenario with insufficient fuel to generate all the electricity needed to meet demand, the study model dispatched the resources providing reserves. If demand still existed after the reserves were depleted, the study calculated the frequency, magnitude, and duration of emergency operating procedures needed to maintain system balance.

The need to implement any emergency operating procedure is an indicator of system stress. System operators must take these actions to protect the region's high-voltage power system. The actions range from smaller steps invisible to the public up to load shedding (rolling blackouts). Load shedding would be implemented as a last resort to avoid an imbalance of supply and demand that could lead to cascading, uncontrolled outages and significant damage to the region's power grid that could spread to other regions.

Caveats

This is a unique study in that it highlights the vital role of fuel security in power system operations. It differs from previous studies in three key ways:

- **First**, it quantifies operational risk by measuring energy shortfalls and levels of system stress.
- **Second**, it focused on the availability of energy over the course of an entire winter – 90 days during December, January, and February, rather than looking at capacity availability on just one winter peak day.
- **Third**, it is not an economic study that considers fuel costs or prices.

22. The study analyzed a wide range of scenarios but did not model every possible future resource combination.

Furthermore, this analysis did not examine the impacts of additional natural gas pipeline capacity on a winter peak day when most or all the pipeline capacity will be used to serve heating customers, not power plants. This study assumed that only four incremental pipeline capacity expansions, already underway or in advanced planning as of summer 2017, would be in service by 2024/2025.[23] This additional capacity is designated for local gas utilities that contracted for the expansion in expectation of growth in demand for natural gas for heating.

This *Operational Fuel-Security Analysis* differs from the economic studies conducted by the ISO at the request of stakeholders. The economic studies consider the wholesale electricity costs that could result from various resource mixes and their fuel costs. The model in this fuel-security analysis does not directly consider fuel costs as a factor in meeting regional demand each day. An unrelated economic study the ISO conducted recently for the New England Power Pool (NEPOOL) should not be confused with this fuel-security analysis.[24] This analysis also differs from the ISO's planning studies in that it focuses on operational impacts and does not evaluate potential solutions.

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. For example, New England electricity prices would be high enough on a given day to attract sufficient imports from neighboring areas to meet New England's needs. Further, the Forward Capacity Market's pay-for-performance requirements, which are designed to provide incentives for resources to perform when needed, are scheduled to be phased in starting June 1, 2018, but the impacts, and the timing of the impacts, are uncertain.

The future hypothetical resource combinations envisioned in each scenario may never materialize, while some may come closer to the future power system than others. Further, power system conditions seldom behave in as orderly a fashion as a study model. Conditions can vary tremendously every day, and even every hour, on a large power grid.

Imports may surge or lag, the output of renewables may be more or less than the average output used in the study, and multiple generators can trip off line on the same day.[25] Fuel replenishment may be easier or more difficult depending on winter conditions, the LNG market may be affected by global conditions that hinder or expedite deliveries, and natural gas delivered via pipeline may or may not be available in sufficient quantities. Higher energy market prices could convince some older generators not to retire, sooner-than-expected advances in technology could change and improve how the system operates, or a combination of some of these factors could alter the future power system.

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23. ICF International, *Forecast of Near-Term Natural Gas Infrastructure Projects*, presentation (October 3, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-infrastructure-forecast-03-oct-2016.pdf. Assumed the following additions: Algonquin Incremental Market (AIM) expansion, 0.345 Bcf/d pipeline capacity, in service January 2017; Atlantic Bridge, 0.13 Bcf/d, planned in service 2017; Connecticut Expansion, 0.07 Bcf/d, planned in service 2017; Continent-to-Coast, 0.11 Bcf/d, planned in service 2017.

24. The *2016 Economic Study Results: Peak-Gas-Day/Hour Capacity and Energy Analysis* (August 1, 2017) (https://www.iso-ne.com/static-assets/documents/2017/08/a3_2016_economic_study_natural_gas_capacity_and_energy_analysis_rev1.pdf) was a continuation of the *2016 Economic Study: NEPOOL Scenario Analysis* (July 24, 2017) (https://www.iso-ne.com/static-assets/documents/2017/07/draft_2016_phase1_nepool_scenario_analysis_report.docx). The ISO conducts economic studies at the request of stakeholders as part of the regional system planning process. The NEPOOL natural gas study evaluated the natural gas system's ability to meet the requirements of natural-gas-fired generation in the stakeholder-designed scenarios used in the *2016 NEPOOL Scenario Analysis*. The NEPOOL study assumed that the natural gas system will have no planned or forced outages and the gas delivery system will be at full capacity on the summer and winter peak days in 2025 and 2030, while this *Operational Fuel-Security Analysis* quantifies the risks associated with insufficient fuel during the 90-day winter period. The NEPOOL analysis also differs from this fuel-security analysis in terms of metrics, scenarios, and the variability in power system inputs.

25. On August 11, 2016, during a hot and humid spell that pushed up demand, a large generator tripped off line followed by several more. In all, nearly 4,300 MW of resources dropped off line unexpectedly over the course of the day. System operators implemented the first two actions of Operating Procedure No. 4 (OP 4), which allowed the system to operate with less than the required level of 30-minute reserves and to dispatch demand-response resources that curtailed their energy consumption. (http://isonewswire.com/updates/2016/10/19/summer-2016-recap-uneventful-until-august.html)

Some New England states are pursuing significant, economy-wide reductions in carbon emissions by 2050. While these efforts can be expected to put upward pressure on demand for electricity as the transportation and heating sectors turn away from fossil fuels, the pace and future effects of these policies on the power system are still unclear.

While the study calculated the number of hours of emergency actions each scenario would require as an indicator of system stress, the resulting numbers should not be construed as a precise prediction. Rather, the results provide a basis for comparing the fuel-security risk of each of the hypothetical resource combinations, with a focus on the relative impact of the five key variables: retirements, LNG, oil tank inventories at dual-fuel generators, imports, and renewable resources. Some resource combinations would result in more hours of emergency actions, while others would require fewer actions or none.

Electricity Demand in Winter 2014/2015 and Winter 2024/2025

The study evaluated each scenario's fuel-security risk throughout the 90-day winter of 2024/2025 based on the levels of consumer demand experienced in December, January, and February of winter 2014/2015.

Winter 2014/2015 serves as the baseline because, while it did not have the coldest days recorded in the past 10 years, it had the most sustained cold as measured by heating-degree days (HDDs).[26] Thus, it provided a wider perspective on the cumulative use of oil and LNG inventories over a full 90 days and the need to replenish these inventories as cold weather persists. If the region experienced colder winters than 2014/2015, as is possible (four winters in the past 38 years were colder, as measured by HDDs), the number and duration of energy shortfalls found in this study would be magnified. A winter with this level of sustained cold has a probability of occurring approximately once every 8 years.

ISO New England is responsible for the reliability of New England's power system under all types of system and weather conditions. No one knows before winter begins how extreme the weather will be. The ISO, the owners of generators and other equipment on the New England power system, and the fuel-supply chains that generators depend on must be prepared for a long, cold winter — perhaps as cold as 2014/2015, or even as cold as one of the winters with more heating-degree days than 2014/2015.[27] While the weather plays a primary role in operating conditions, so do other key variables, as highlighted in this study.

The hourly demand levels from winter 2014/2015 were adjusted to reflect the ISO's forecast for slightly higher net peak demand in extreme winter conditions in 2024/2025.[28] All the scenarios incorporate the ISO's latest forecasts for the effects of energy efficiency and distributed PV generation, which reduce the amount of electricity needed from the larger regional grid.

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26. A degree day is a measure of heating or cooling and an indication of a building's demand for energy (fuel consumption). A zero-degree day occurs when no heating or cooling is required. As temperatures drop, more heating days are recorded; when temperatures rise, more cooling days are recorded. The base point for measuring degree days is 65 degrees Fahrenheit (˚F). Each degree of a day's mean temperature above 65˚F is counted as one cooling-degree day, while each degree of a day's mean temperature below 65˚F is counted as one heating-degree day. A day's mean temperature of 90˚F equals 25 cooling-degree days, while a day's mean temperature of 45˚F equals 20 heating-degree days.

27. Number of HDDs for 2014/2015: 3,551. Coldest winters as measured by HDDs: 1993/1994: 3,678; 2002/2003: 3,611; 1980/1981: 3,573; 1981/1982: 3,568.

28. ISO New England, *2017–2026 Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT) (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/2017_celt_report.xls.

While actual power grid conditions could change earlier or later than the target year, the study used winter 2024/2025 as the target for several reasons. By winter 2024/2025, the outlook for power system reliability is uncertain. Given the pace of power system transformation and increasing economic pressures on the remaining oil, coal, and nuclear power plants, more retirements are expected in the next decade. The years until winter 2024 give the region time to address these challenges but don't provide any buffer to defer decisions about the region's fuel-security risk.

Overview of the Scenarios

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. Several "combination" scenarios also represent a range of resource and fuel types that could realistically be expected to be available in the 2024/2025 timeframe. The reference case provides a baseline for all the other scenarios, which included differing levels of the five variables.

Eight scenarios adjusted just one of the five variables at a time, up or down from the reference case level, to assess the relative impact of each variable. For example, two scenarios were developed to show the effects of differing LNG levels. Four variables – retirements, electricity imports, renewables, and dual-fuel oil inventories – were held constant, and in one scenario, LNG injections were *increased* above the reference case level, and in the other scenario, they were *decreased* below the reference case. Retirements and renewables were exceptions – neither was adjusted down from the reference case level. And for retirements, a higher level represented a greater loss of resources and is considered less favorable, while with all other variables, a higher level is considered positive or favorable.

Two scenarios represented the most and least favorable levels of each variable to show the best- and worst-case outcomes. For the best-case scenario, all five variables were modeled at levels that would minimize fuel-security risk, including low retirements. For the worst-case scenario, all five variables were modeled at less-favorable levels that would raise fuel-security risk, including greater retirements.

The four "combination" scenarios adjusted more than one variable to represent a blend of outcomes, including cases with less LNG, more LNG, higher retirements of non-gas-fired generators, and retirements of all at-risk non-gas-fired power plants coupled with very high levels of renewables and imports.

Eight high-impact scenarios assessed the effects of an outage of four major energy facilities for the entire winter on the reliability of the power system. The impacts were assessed on a system represented by the reference case and also by the combination case with the highest levels of retirements and renewables. The outages of the following key energy facilities were studied:

- A compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and cutting off fuel to generators with a combined capacity of about 7,000 MW
- The loss of Millstone Nuclear Power Station in Connecticut, one of the region's remaining two nuclear facilities, eliminating 2,100 MW of baseload power
- The loss of the Canaport LNG import and regasification facility in New Brunswick, Canada, eliminating as much as 1.2 Bcf/d of gas that could be injected into the New England and Maritimes pipeline systems

- A disruption to the Distrigas LNG import, storage, and regasification facility in Massachusetts, eliminating all the natural gas that can fuel the nearby, 1,700 MW gas-fired Mystic 8 and 9 generators and as much as 0.435 Bcf/d that can be injected by Distrigas into the Algonquin and Tennessee interstate gas pipeline systems (0.3 Bcf/d) and the local gas utility's distribution system (0.135 Bcf/d)

Key Resource Assumptions

Several key assumptions about New England's future energy landscape are common to all the scenarios.

Natural Gas Supplies

On the basis of a study ICF International conducted for the ISO on probable natural gas infrastructure expansions in the region, this fuel-security analysis assumed that the region's natural gas supply infrastructure will have been expanded only incrementally beyond its current capability by 2024, including a recently completed pipeline expansion and three smaller expansions underway.[29] The ICF study found that these four planned or recently completed expansions will total 0.65 Bcf by 2018, increasing New England's pipeline capacity from 4.04 Bcf/d to 4.69 Bcf/d over the five pipelines bringing natural gas into New England from New York and Canada.

The pipeline expansions are sized to meet the future capacity requirements of the natural gas utilities that contracted for the added capacity; pipelines aren't built speculatively to accommodate potential future customers, such as natural gas generators. As such, any incremental pipeline capacity is expected to be used by natural gas utilities to serve their growing customer base.

Two natural gas fields off the coast of Nova Scotia – Sable Island and Deep Panuke – are expected to be depleted before 2025. This fuel-security study assumed that the depletion of these gas fields would leave the Canadian Maritimes with just two sources of natural gas: Canaport and the Maritimes and Northeast pipeline that carries gas between Canada and Maine.

The study assumes that by 2024/2025, on most days, some natural gas will flow via pipelines from New York or Québec, through New England via the M&N pipeline, to the Maritimes to serve heating customers.[30] Pipeline gas will be used more often than Canaport's LNG because natural gas is typically cheaper than LNG. On high-demand days when pipeline gas is insufficient, higher-priced LNG from Canaport or other sources will be needed to augment the pipeline gas supply. Under these conditions, the M&N pipeline will function as an internal distribution system carrying gas from the west to Canada, rather than as a separate source of gas from Canada to New England. Considering this shift, the study treated the M&N pipeline's 0.833 Bcf/d capacity as an internal regional pipeline rather than as a source of natural gas from outside New England.

As a result, the pipeline infrastructure capable of delivering natural gas into the region in 2024/2025 would stand at 3.86 Bcf/d over four pipelines from New York and Québec: Algonquin Gas Transmission (1.9 Bcf/d from New York), Tennessee Gas Pipeline (1.4 Bcf/d from New York), Iroquois Gas Transmission System (0.26 Bcf/d from New York), and Portland Natural Gas Transmission (0.3 Bcf/d from Québec).

The study assumed that LNG will be imported to three sources in 2024/2025: Canaport, Distrigas, and the Northeast Gateway Deepwater Port buoy off Gloucester, MA.

29. ICF International, *Forecast of Near-Term Natural Gas Infrastructure Projects*, presentation (October 3, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-infrastructure-forecast-03-oct-2016.pdf (Natural Gas Infrastructure Forecast).

30. The study did not factor in demand for natural gas to serve power plants in the Maritimes.

The maximum injection capability from each of the LNG facilities is 1.2 Bcf/d from Canaport, 0.4 Bcf/d from the Northeast Gateway buoy, and a maximum injection of 0.435 Bcf/d into the interstate pipeline system and the local gas utility system from the Distrigas facility. The maximum LNG that can be injected into the Canadian Maritimes and New England interstate natural gas pipeline systems is 2.04 Bcf/d.[31]

Combined, the expected pipeline capacity of 3.86 Bcf/d, plus the 2.04 Bcf/d maximum LNG that could be regasified and injected into the pipeline systems serving New England and the Maritimes, totals about 5.9 Bcf/d.

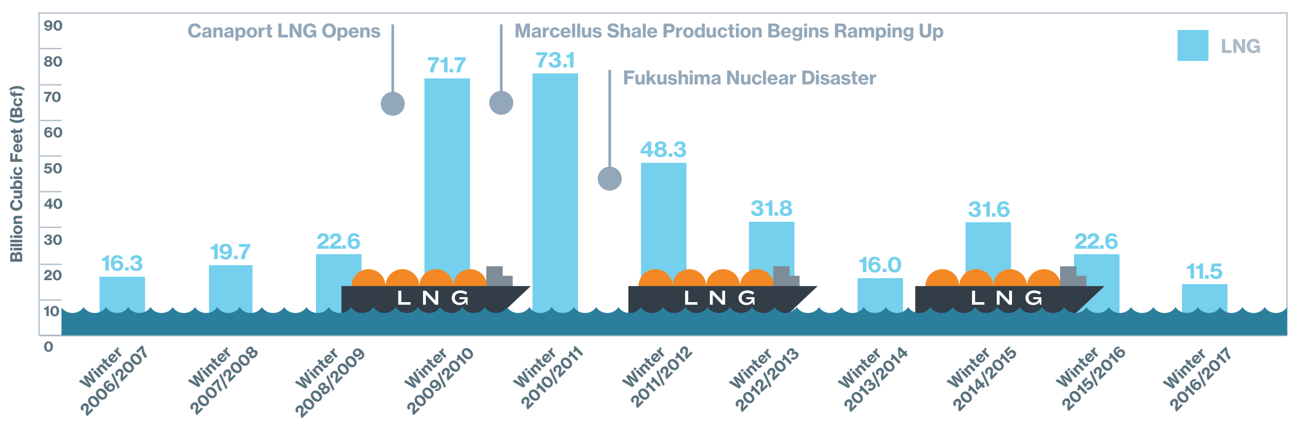
Natural gas deliveries from LNG facilities to New England pipelines have varied over the past 15 years, from none on one day in December 2016 to the maximum delivery observed at any one time of 1.25 Bcf on one day in February 2016.[32] The maximum amount of regasified LNG injected into the region's pipeline system in any scenario in this study was 1.5 Bcf/d, and the least was 0.65 Bcf/d in a scenario with an outage at Canaport.

Tracking LNG scheduled deliveries to the region's pipelines over an entire, 90-day winter season, the lowest level of LNG deliveries in the past 11 years arrived during the mild winter of 2016/2017, at 11.5 Bcf. The highest was 73.1 Bcf in winter 2010/2011, with the second-highest in 2009/2010, at 71.7 Bcf. The region's imports of LNG during winters going back to 2006/2007 are illustrated in Figure 2.

LNG Deliveries to New England Hinge on a Global Market and Winter Weather Predictions

Regional LNG deliveries vary from winter to winter for a variety of reasons, including the level of firm contracts as well as global LNG futures prices. Forecasts for a severe winter can also cause futures prices to increase. When New England's forward prices are high, destination-flexible LNG spot cargoes are likely to be attracted to the region. The primary driver for the significant increase in LNG deliveries in the winters of 2009/2010 and 2010/2011 was the new Canaport LNG import terminal in New Brunswick. Rising Marcellus shale gas production, starting in the 2010 timeframe, has lowered natural gas prices for most of the year, making LNG less competitive on price, on average. The Fukushima nuclear plant meltdown in 2011 caused a significant increase in Japan's use of LNG.

Figure 2: Winter LNG Deliveries to New England Interstate Pipelines



Note: Graph does not include the Mystic 8 and 9 gas-fired generators' fuel supply from the LNG facility.

Source: Data from NatGas Analyst Tool by Genscape, a part of DMG Information (DMGI), www.genscape.com, based on scheduled deliveries posted to gas-industry bulletin boards

Natural Gas Demand

A key factor in this study is how much natural gas will be left over for power generators after natural gas distribution companies have served their heating customers. A second study conducted in 2016 by ICF International for the ISO projected how much natural gas the gas utility companies will need in

31. The Distrigas LNG injection capacity does not count any LNG that goes directly to supply the Mystic 8 and 9 generators because this LNG is not available for injection into the interstate or local distribution pipeline systems and is not available to other generators. Likewise, the LNG used to supply Mystic 8 and 9 is not counted under the LNG caps modeled in the study scenarios.

32. This excludes any LNG directed to Mystic 8 and 9.

2024/2025.[33] This ICF study found that in winter 2014/2015, natural gas demand for heating totaled 4.4 Bcf on the winter peak day. The study also forecasted that on the coldest winter day, peak demand from local gas utilities alone could reach 5.45 Bcf/d by 2025.

Total demand for the entire year from gas utilities was 515 Bcf in 2014. The ICF study concluded that the annual demand for natural gas from local gas utilities will rise at an average of just under 2% per year, up to 591 Bcf per year in 2025 and 620 Bcf per year in 2030. As local gas utilities continue converting customers to natural gas heating, this demand will put additional pressure on gas availability for electric generation.

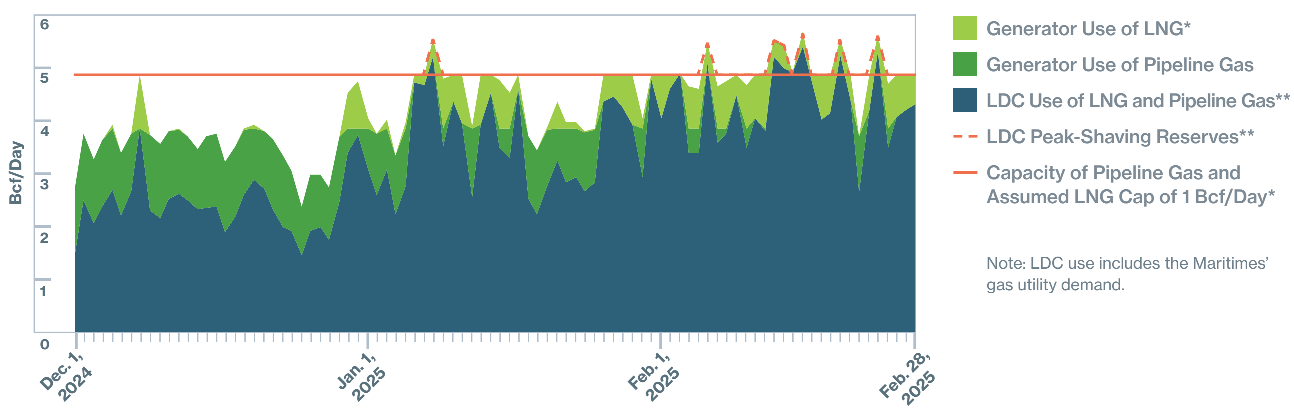
While Canada is moving to retire all its coal- and oil-fired power plants by 2030, this study does not attempt to project or include the potential impacts of additional gas demand from the electric generation sector in the Canadian Maritimes on New England's fuel security. The Maritimes' gas utility demand was included because, by 2024/2025, its heating demand is likely to be served entirely by Canaport or by importing natural gas through New England via the M&N pipeline. Either way would result in less natural gas for New England.

Figure 3 shows the effect of heating demand by local gas utilities in New England and the Maritimes on the availability of natural gas for generators, from both pipelines and from LNG.

Natural Gas Availability for Power Plants Is a Function of Heating Demand for Natural Gas

The growing use of natural gas to meet heating needs on the coldest days in New England and the Canadian Maritimes can limit the availability of natural gas, from both pipelines and LNG facilities, for New England's power plants. Local gas distribution companies (LDCs) have priority contracts with natural gas pipelines to acquire gas for their heating customers. As shown here, on some days during winter 2024/2025, the generators' need for fuel is projected to reach or exceed the region's total amount of pipeline capacity plus the assumed maximum LNG injection of up to 1 Bcf/d in the reference case. Fully meeting electricity demand on these days will hinge on the fuel inventories of non-gas-fired power resources, particularly oil (as illustrated in Figure 5 on page 36). On days when LDC demand stresses the natural gas infrastructure capacity, the gas utilities can tap into LNG reserves they have stored at "peak-shaving" facilities. The regulated LDCs have purchased the LNG stored in these tanks, which cannot be sold to power plants or other parties. While these reserves aren't directly available to generators, they may sometimes make more natural gas available during the operating day.

Figure 3: Winter 2024/2025 Supply of Pipeline Gas and LNG Compared to Use
(Reference Case)



*Graph does not include the Mystic 8 and 9 gas-fired generators' fuel use or supply from the LNG facility.

**Per data from ICF International, *New England LDC Gas Demand Forecast Through 2030* (December 14, 2016, presentation to Planning Advisory Committee) and *The Future of Natural Gas Supply for Nova Scotia* (March 28, 2013, for Nova Scotia Department of Energy).

33. ICF International, *New England LDC Gas Demand Forecast Through 2030,* PAC presentation (December 14, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-ldc-demand-forecast-03-oct-2016.pdf.

Coal-Fired Generation

The study assumed that New England would have no more coal-fired power plants in winter 2024/2025.

Renewables

For each scenario, the study assumed the region would have at least 6,600 MW (nameplate capacity) of renewable resources in winter 2024/2025. This reflects the region's current amounts of wind (1,200 MW of onshore wind, 30 MW offshore) and other existing renewables, such as biomass, refuse, and solar resources (960 MW), plus all the behind-the-meter solar PV forecasted to be installed by 2024.

These assumptions were developed by studying proposed projects, as well as initiatives by the New England states. For example, the ISO's 2017 PV Forecast anticipates the region will have 4,430 MW of installed nameplate PV capacity through 2024.[34] The ISO Interconnection Queue currently includes proposals for about 4,600 MW of onshore wind and about 2,700 MW of offshore wind (as of August 15, 2017).[35] However, historically, about 68% of proposed megawatts are never constructed.

The model also incorporated into all scenarios the ISO's forecasts for growth of energy-efficiency measures. The ISO's forecast estimates that passive EE measures will lower peak demand by 3,907 MW in winter 2024/2025, to 20,761 MW in extreme winter weather. Winter peak demand is expected to decline about 0.7% per year over the 10-year planning period.[36]

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. However, these assumptions are not prescriptive; the megawatts modeled for one type of renewable resource in some scenarios could also be coming from other types of renewable resources, or even EE measures.

Several scenarios raised the level of renewables from 6,600 MW to 8,000 MW by adding nearly 1,400 MW of offshore wind by 2024. The cases with 8,000 MW of renewables also raised imports by 1,000 MW, to 3,500 MW, reflecting the assumption that an additional, hypothetical transmission line will be built by 2024 to address state goals for clean energy from Canada or New York.

One combination case raised renewables to 9,500 MW, the highest level of renewable resources assumed in this study. This scenario assumed that the region will have 2,000 MW of offshore wind by 2024, and that behind-the-meter solar PV will grow at a faster pace than currently projected, adding 900 MW of PV to the current forecast of 4,430 MW, for a total of 5,330 MW of BTM PV.

The cases with 9,500 MW of renewables also assumed imports of clean energy will grow by 1,000 MW as the result of higher imports over the new, hypothetical transmission tie. Adding the renewables and the 1,000 MW of additional imports brings the total clean energy assumed in this scenario to 10,500 MW (nameplate), or nearly a third of the region's current generating capacity.

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34. ISO New England, *Final 2017 PV Forecast*, presentation (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/2017_solar_forecast_details_final.pdf.

35. ISO New England, "Interconnection Request Queue," webpage (August 2017), https://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue.

36. ISO New England, *2017–2026 Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT) (May 1, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/2017_celt_report.xls.

Table 1 shows the assumptions for the renewables included in the reference case, the scenario with more offshore wind and imported clean energy, and the scenario with the highest level of renewables.

Table 1: Renewable Resource Assumptions

Case Scenario	Renewables Total MW (rounded)	Breakdown MW			
		Onshore Wind	Offshore Wind	PV	Other Renewables
2017	4,600	1,200	30	2,400	960
Reference Case	6,600	1,200	30	4,430	960
More Renewables	8,000	1,200	1,400	4,430	960
Max Renewables	9,500	1,200	2,000	5,330	960

Imports

Thirteen high-voltage transmission lines connect New England to neighboring power grids in New York and Québec and New Brunswick, Canada. Most of the time, New England is importing power over these lines from its neighbors.

Some of the New England states' goals that call for more clean energy, including from Canada and New York, are incorporated into some scenarios that increased imports above the 2,500 MW reference-case level. These additional imports, at 500 MW and 1,000 MW, raised total imports to 3,000 in one scenario and 3,500 in several other scenarios. The additional energy was assumed to be composed of clean energy over a hypothetical new transmission line from Canada or New York. Most of those imports would likely be coming from Québec most of the time.[37]

New England and its neighbors experience winter weather at the same time and, in fact, the demand for power in Québec and New Brunswick peaks in winter. As a result, their imports to New England could be limited as they serve their own populations. This study does not attempt to quantify these effects, however.

37. The study also assumed that New England would receive 500 MW of emergency imports from its neighbors during times of system stress when Operating Procedure No. 4 was implemented.

Methodology

The study modeled each scenario's future fuel-security risk in several steps, including:

- Calculating the amount of electricity required to meet demand each hour of a 90-day winter, from December 1, 2024, through February 28, 2025
- Calculating how much natural gas would be available after all heating demand were served, as well as the levels of oil stored on site at oil-fired and dual-fuel power plants
- Calculating how much electric energy could be generated by each fuel type
- Comparing the amount of fuel required with the level of fuel the region's fuel-delivery system could supply in each hypothetical scenario
- Assessing the magnitude and duration of emergency actions required, up to and including rolling blackouts after all operating reserves were depleted, if the fuels available were not sufficient to meet demand

The study model was based on winter conditions when oil and gas fuels were expected to be tight, so demand was met by dispatching non-oil-fired and non-natural-gas-fired generators first. Resources in this category included renewables, such as on- and offshore wind, solar PV, other renewables (e.g., biomass, refuse, landfill gas); nuclear; and hydro, including pumped storage. Next in the dispatch order were imports, then natural-gas-fired generators. If all power plants were already operating at full capability, and more demand for power still needed to be served, dual-fuel generators with stored oil would be dispatched. Finally, oil-only generators would be used.

If not enough stored oil and LNG were available to generate all the power needed to meet the remaining demand, the study calculated the frequency, magnitude, and duration of the emergency actions needed to maintain system balance and meet reliability requirements.

Metrics: How System Stress Was Measured

The study quantified how often energy shortfalls – that is, insufficient fuel to generate all the electricity needed – would occur that would require the ISO to use special procedures to serve consumer demand while maintaining the required level of reserves.

These operating procedures include tools used commonly by the ISO to manage imbalances in supply and demand, as well as emergency actions in more serious conditions. These procedures currently include allowing 30-minute reserves to be depleted, calling on demand-response resources to reduce energy usage, arranging for emergency purchases from neighboring systems, as well as tools used infrequently, such as voltage reductions (also known as brownouts). When deploying these emergency procedures, the ISO can call for the action that will best address the situation at hand; no specific order of implementation is required. If necessary, in an extreme emergency, the ISO can also skip these procedures and implement load shedding immediately.

As system stress intensified in each scenario, the study model progressed through a series of operating procedures, from those that have no impact on electricity service to consumers; to procedures that have minor public impacts, including requests for voluntary conservation and voltage reductions; and then to the depletion of 10-minute operating reserves before finally resorting to load shedding.

Ten-minute reserves are resources that can come on line within 10 minutes to cover for the unexpected loss of a resource. The depletion of 10-minute operating reserves is a significant step – once these reserves are depleted, any resource loss or transmission line trip that cuts imports would trigger load shedding. This would be necessary to operate the system reliably and comply with mandatory national standards to avoid uncontrolled outages that could cascade across New England and threaten the entire interconnected system of power grids from the Atlantic Ocean to the Rocky Mountains.

Required Reserve Levels

ISO New England is required to carry operating reserves to respond to the unexpected loss of any resource on the power system, such as when a large generator trips off line, and almost all the procedures employed in this analysis are used to maintain the required level of reserves. Reserves are insurance – the power plants providing reserves are ready to respond quickly to replace the lost electricity and recover system equilibrium, so that no one loses power and cascading outages are avoided. The North American Electric Reliability Corp., the Northeast Power Coordinating Council, and ISO New England all have requirements for maintaining reserve levels.[38] Beyond the operational risks involved in having insufficient reserves, not meeting these reserve requirements carries consequences, including fines.

The ISO maintains 10-minute operating reserves sufficient to recover from the loss of the largest source of power, whether it's a large generator or transmission line importing power. That's normally between 1,560 MW and 2,250 MW. Thirty-minute reserves – generators that can come on line within 30 minutes – are also required to help the system replenish the 10-minute reserves. Thirty-minute reserves are equivalent to 50% of the second-largest source of supply, which is normally about 625 MW. The depletion of 30-minute reserves typically is the first action taken when the ISO declares Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*.[39] The study assumed 2,300 MW of reserves.

Operating Procedure No. 4

Operating Procedure No. 4 is the procedure used most often by ISO New England 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 (see Table 2). Most OP 4 actions require no public notification or public response.

The fuel-security analysis assessed the need to implement OP 4 in each scenario in two parts: Actions 1 through 5 and Actions 6 through 11. Actions 1 through 5 are designed to work with transmission owners and other market participants to manage through stressed system conditions.[40] If Actions 1 through 5 are not sufficient to address the problem, the ISO may implement higher-level actions that may be more obvious to the public, such as voltage reductions and urgent appeals for public conservation.

38. North American Reliability Corp., "Compliance & Enforcement," webpage (2016), http://www.nerc.com/pa/comp/Pages/Default.aspx.

Northeast Power Coordinating Council, "Standards," webpage (2017), https://www.npcc.org/Standards/default.aspx.

ISO New England, "Reliability Standards: Development and Compliance," webpage (2017), https://www.iso-ne.com/about/what-we-do/in-depth/reliability-standards-development-and-compliance.

39. ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency* (July 5, 2017), https://iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

40. In this study, demand-response resources were dispatched to reduce consumption when OP 4 Action 2 was implemented during times of system stress, reflecting the current actions available. However, on June 1, 2018, demand-response resources will be integrated into New England's wholesale energy markets and will be dispatched based on price in the same way generators are dispatched and will not be available as emergency resources. The study did not reflect this change because this will be the first time demand-response resources will be fully integrated into economic dispatch systems, so the price and other aspects of their offers, which affect when they will be dispatched to reduce energy consumption, is uncertain at this time. Real-time emergency generation, dispatched in Action 6, has been in decline due to environmental restrictions and will no longer be available as of June 1, 2018.

Table 2: ISO Operating Procedure No. 4 Actions

OP 4 Action	Action Description
1	▶ Implement a Power Caution, which is a public notification that electric power reserves can no longer be maintained using normal measures. Although full reserves are not being maintained, utility personnel will begin to take steps to manage these reserves. ▶ Advise resources with a capacity supply obligation (CSO) to prepare to provide capacity and notify "settlement-only" generators with a CSO to monitor reserve pricing to meet their obligations. ▶ Begin to allow the depletion of 30-minute reserves.
2	▶ Dispatch real-time demand resources in the amount and location required.
3	▶ Request voluntary load curtailment of market participants' facilities.
4	▶ Implement a Power Watch, which is a public notification that further steps to manage capacity could affect the public. Issue a public appeal for voluntary conservation.
5	▶ Schedule emergency energy transactions.
6	▶ Implement voltage reductions requiring more than 10 minutes. ▶ Dispatch real-time emergency generation.
7	▶ Request generation without a capacity supply obligation to provide energy for reliability purposes.
8	▶ Implement voltage reductions requiring 10 minutes or less.
9	▶ Request activation of transmission customer generation not contractually available to market participants during a capacity deficiency. ▶ Request voluntary load curtailment by large industrial and commercial customers.
10	▶ Implement a Power Warning. Issue urgent radio and TV appeal to the public for voluntary conservation. Public appeals are made when other efforts (e.g., emergency purchases, voluntary curtailment, contracted curtailment, and voltage reduction) have been unsuccessful in bringing supply and demand back into balance.
11	▶ Request state governors' support for ISO appeals for conservation.

ISO Operating Procedure No. 7

If OP 4 actions are not sufficient, the ISO may start depleting 10-minute reserves, which leaves the system vulnerable to uncontrolled outages that could cause significant damage to power system equipment and spread to other regions. If the 10-minute-reserves were depleted, implementation of controlled outages – rolling blackouts – could be required to maintain system balance. ISO New England Operating Procedure No. 7 (OP 7), *Action in an Emergency*, is the emergency procedure the ISO follows to implement load shedding.[41]

OP 7 is employed when there is unusually low frequency on the system, equipment overload, a capacity or energy deficiency, unacceptable voltage levels, or any other event the ISO deems an operating emergency in either an isolated or widespread area of the system. The objectives of OP 7 are as follows:

- Protect the reliable operation of the Eastern Interconnection
- Restore balance between customers' load and available generation in the shortest practicable time
- Minimize risk of damage to equipment
- Minimize interruption of customer service

When OP 7 is implemented, the ISO orders local control centers operated by transmission owners to reduce a specific quantity of system load. They do this by manually opening distribution system breakers to disconnect blocks of customers. Blocks of customers are disconnected and reconnected to the system sequentially, which is why load shedding is sometimes called "controlled outages" and "rolling blackouts." Rolling blackouts do not affect all customers in the affected area at the same time.

The study calculates the number of times each operating procedure would be needed throughout a 90-day winter in each scenario, the number of hours each procedure would be needed, and the quantity of consumer demand that would go unserved and for how long. These measurements, or metrics, of the number and severity of energy shortfalls illustrate the level of risk involved in each scenario and the relative benefits of the five key variables.

41. ISO New England Operating Procedure No. 7, *Action in an Emergency* (January 17, 2017), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op7/op7_rto_final.pdf.

Study Results

The study results provide a basis for comparing the fuel-security risk of each of the 23 hypothetical resource combinations analyzed, with a focus on the relative impact of the five key variables: retirements, LNG, oil tank inventories, imports, and renewable resources. Although not all possible resource combinations were studied, the results show that some resource combinations would require more hours of emergency actions, while others would require fewer actions or none. Looking at all the scenarios together (see Figure 4 and Appendix A) provides perspective on the relative levels of fuel-security risk that could be present, depending on how the New England power system evolves, as well as approaches the region can consider to ensure power system reliability. The results should not be construed as a precise prediction.

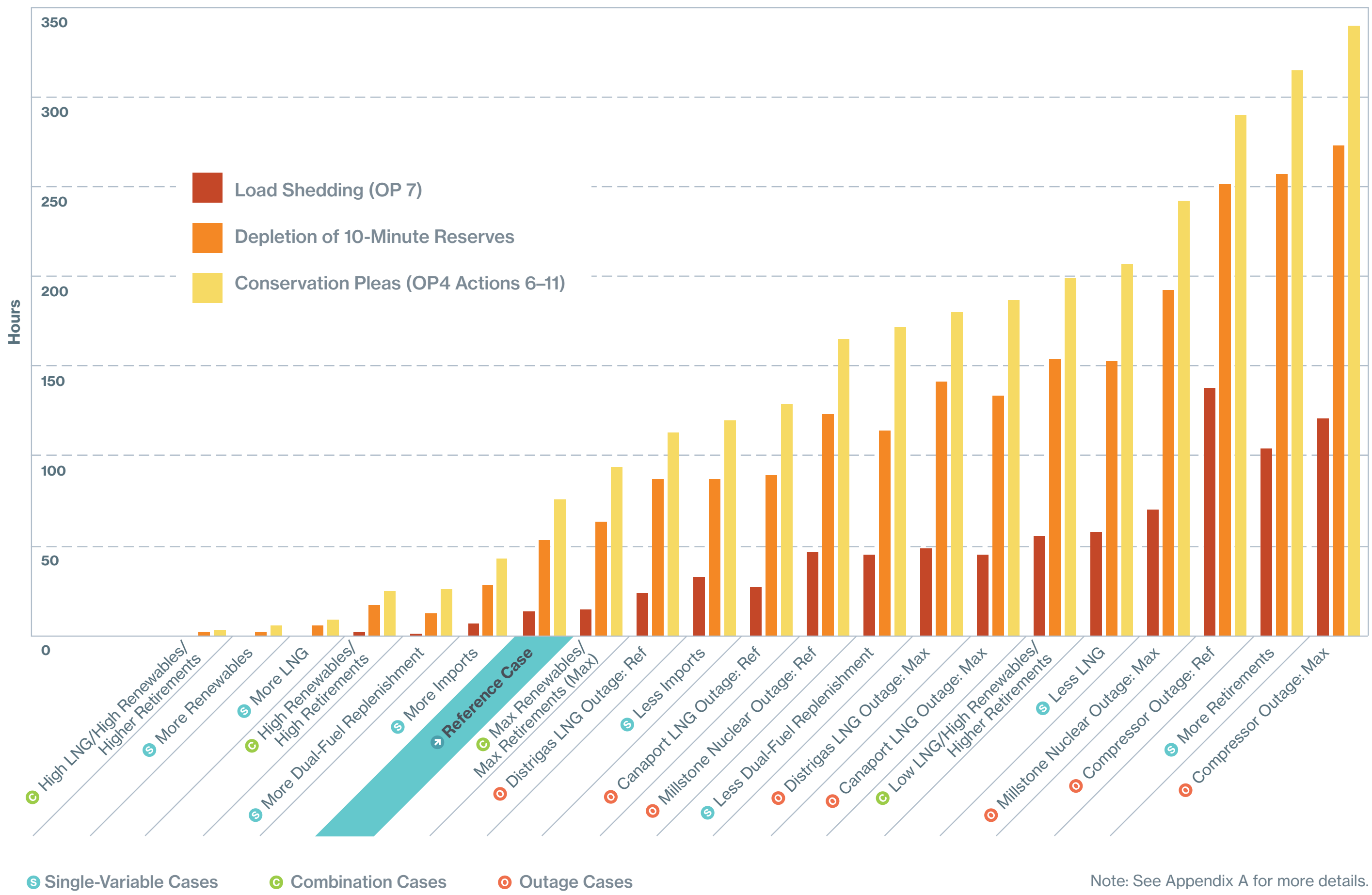
The results show that in most future power system scenarios studied, adequate levels of fuel would not be available throughout the entire winter. Without adequate fuel, the region's power plants would be unable to generate all the electricity needed to meet demand and required reserves – even after accounting for the demand-reducing effects of behind-the-meter solar arrays and energy-efficiency measures. The resulting energy shortfalls would require a range of operating procedures and emergency actions, up to and including load shedding.

Under the wide range of scenarios studied, in all but the most favorable future resource-mix combinations and in all key resource outage scenarios, the study shows that New England's fuel-security risk could become acute by winter 2024/2025, requiring frequent use of emergency actions. In some scenarios, energy shortfalls can be managed with relatively low-impact operating procedures that require no public notification or public actions to maintain system balance. However, most scenarios would require multiple hours of load shedding.

Current Trends Are Pushing the Power System toward Greater Risk

The major trends affecting the New England power system are moving in a negative direction. This analysis looked at a wide range of future resource mixes to assess the operational impact. All but one of the 23 modeled scenarios (the high [i.e., positive] boundary case, not shown here because it is unlikely to materialize) would lead to some level of emergency actions during winter 2024/2025 (i.e., OP 4 Actions 6–11), as well as hours when the ISO would have to deplete 10-minute reserves to keep the lights on. All but four scenarios would require some level of load shedding (i.e., OP 7). (The low [i.e., negative] boundary case resulted in even more hours of emergency actions but was omitted because it also is unlikely.)

Figure 4: Hours of Emergency Actions under Modeled Scenarios, Ordered Least to Most



Note: See Appendix A for more details.

A summary of the reference case and its results is presented below.

Reference Case

The reference case is 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 path. It does not incorporate state policy goals and requirements for clean energy; other scenarios account for the potential effects of these initiatives on the region's resource mix. While the reference case results discussed below indicate tight operating conditions, its purpose is to provide a point of orientation for all the other scenarios. Neither the reference case nor any of the other cases are predictors of the future, and none of the scenarios should be viewed as ISO New England's preferred scenario.

Reference Case Assumptions

- **Retirements: 1,500 MW.** The ISO projects that the region's 23 remaining coal- and oil-fired generators, with a capability of 5,400 MW, are at risk of retirement. The reference case assumes that by 2024, nine of these power plants, representing 1,500 MW, will be retired. This includes the remaining coal-fired power plants as a result of stricter emissions limits and economic pressures. The retirements in the reference case are in addition to the 4,200 MW recent and pending retirements that will be complete by 2019.

  None of the 22 other scenarios reduced retirements below the 1,500 MW reference case level; several increased retirements to 4,500 MW and some would retire all the remaining 5,400 MW of coal- and oil-fired power plants.

- **LNG injections: 1 Bcf/day.**[42] The maximum amount of regasified LNG that can be injected into New England's pipeline system is about 2.04 Bcf/d. In recent years, the most LNG injected at any one time into New England's pipeline system was 1.25 Bcf/d, on one day in February 2016. The reference case assumed that 1 Bcf is the maximum level of LNG that will be available for both heating and power generation on any given day. Less LNG would be needed on some days, and on some days, more.

- **Dual-fuel oil tank fill rate: two times per winter period.** Dual-fuel power plants' oil tanks in the reference case were assumed to be filled two times during the 90-day winter: once before the start of the winter and one more time during the winter. For example, a power plant with a 10,000-gallon tank will start the winter with a full tank and then refill it another time, for a total winter oil inventory of 20,000 gallons.

  The fill rate of two times was chosen because most generators' oil tanks hold about 10 days' worth of oil, so filling their tanks twice would allow most dual-fuel generators to burn oil for about 20 days. Environmental restrictions currently limit many oil-fired generators in New England to burning oil for no more than approximately 30 days per year. Running for 20 days would put most power plants near their annual limit, a moderate assumption for the reference case. The maximum fill rate in any of the scenarios was set at three times, which would put many generators at their annual limit.

  Massachusetts is implementing stricter emissions restrictions that will significantly reduce the amount of time generators in the state could run on oil, but the new Massachusetts regulations are not factored into the future scenarios. Another limitation not factored into the study was the fact that some dual-fuel generators have oil tanks that hold less than 10 days' worth of oil, limiting how long they can run on oil during a cold snap.

- **Imports: 2,500 MW.** The reference case assumes that the level of imports would be 2,500 MW because on average, over the last five winters, about 2,500 MW was flowing into New England from these neighboring grids just over 60% of the time; most of the rest of the

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42. As shown in Figure 3, the gas utilities can tap into LNG reserves they have stored at "peak-shaving" facilities when necessary for their purposes. While these reserves aren't directly available to generators, they may sometimes make more natural gas available from other sources during the operating day.

time, about 2,000 MW was imported. The highest observed was about 4,000 MW, just 1% of the time. The study also assumed that if emergency actions were implemented, New England would receive an additional 500 MW of emergency imports from its neighbors, for a total of 3,000 MW of imports in the reference case.

- **Renewable resources: 6,600 MW.** The reference case assumed that New England's fleet of renewable resources will total 6,600 MW (nameplate) in winter 2024/2025, with no new wind or hydro imports. This incorporates the region's current renewable portfolio of about 2,200 MW of wind and other existing renewables such as biomass and refuse and solar resources. To this total, the reference case adds about 4,400 MW of new behind-the-meter solar PV forecasted to be installed by 2024. This estimate of future renewables provides a baseline for comparison from today to scenarios that incorporate additional renewables as planned or required by state legislation.

  None of the scenarios in this study reduced renewables below the reference case level of 6,600 MW.

Reference Case Results

The study found that in a severe winter in 2024/2025, a resource mix represented by the reference case could see multiple hours of emergency actions, including exposure to as many as 14 hours of load shedding spread over six days. Less severe emergency actions (OP 4 Actions 6 to 11) would be required for more than 75 hours, and the depletion of 10-minute reserves – often the last step before load shedding – would be needed for more than 50 hours (see Table 3).

Table 3: Reference Case Assumptions and Results

						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)
Reference Case (Ref)	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6

The study found that, while the assumed maximum available LNG of 1 Bcf/d was not needed every day in the reference case, it was needed on 35 days, and this still would not be sufficient to avoid load shedding or other emergency actions on six days.

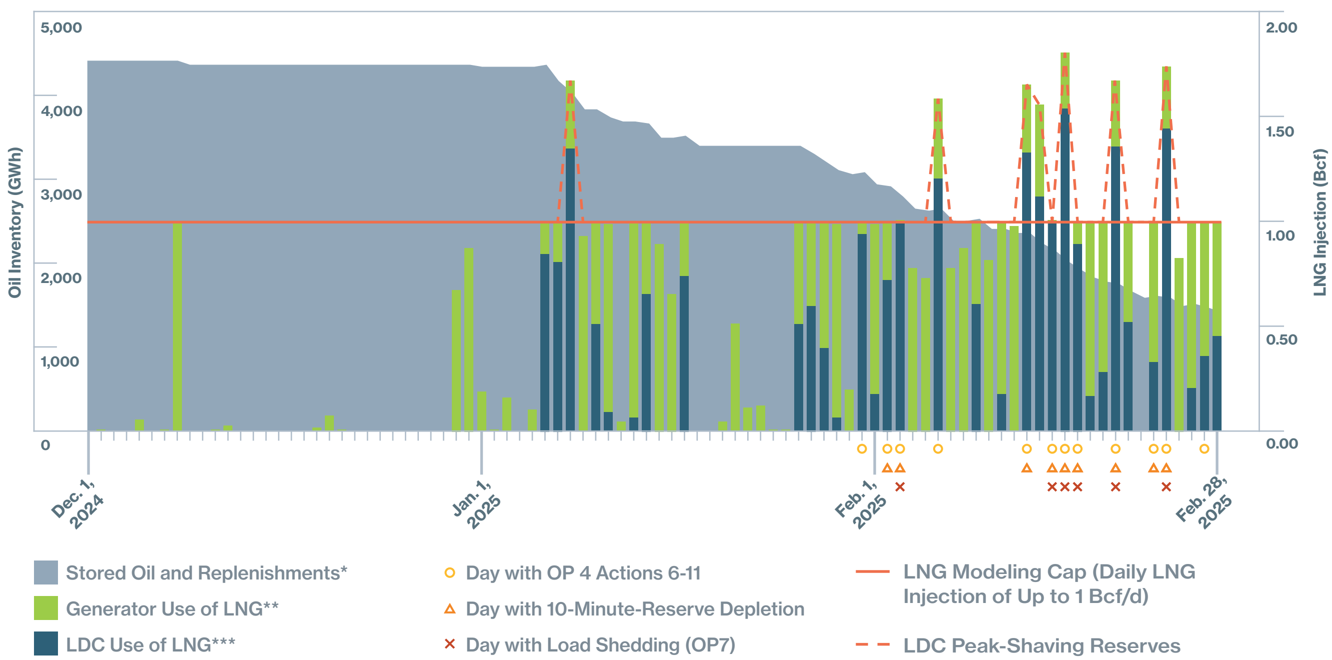
Overall, at the slightly higher load levels projected for 2024/2025 but with a cold winter like 2014/2015, the region as a whole would use 62.4 Bcf of LNG over the entire winter for both heating and power generation. This amount is significantly more than the 34.9 Bcf injected into the interstate pipelines, on average, over the past 10 winters and almost double the 31.6 Bcf of LNG injected during winter 2014/2015.

Figure 5 illustrates the daily use of LNG by both gas utilities to serve heating demand and power generators throughout the winter of 2024/2025 in the hypothetical reference case, which assumed a maximum of 1 Bcf/d of LNG injections. The graph also shows declining oil inventories, even in a scenario based on the assumption that dual-fuel oil tanks would be filled twice.

Emergency Actions Track LNG and Oil Availability

Building off Figure 3 on page 25, this chart takes a closer look at the relationship between regional LNG supply and demand, declining oil inventories as winter progresses, and system reliability. On days when LDC demand for LNG is high, less natural gas is available for generators. When LDC demand stresses the capacity of the natural gas infrastructure, LDCs can tap into LNG reserves stored at their "peak-shaving" facilities. While these reserves aren't directly available to generators, their use may sometimes make more natural gas available during the operating day. The model shows that as winter progresses, oil inventories decline, while days with high heating demand tend to occur more often. If all or most of the LNG is being used for heating when oil inventories have declined, the region will likely require more frequent emergency actions on the power system (e.g., pleas for energy conservation [OP 4 Actions 6–11] and load shedding [OP 7]).

Figure 5: Projected Winter 2024/2025 Oil and LNG Use and Emergency Actions
(Reference Case)



* Includes distillate and residual oil. This scenario assumed dual-fuel units' oil tanks would be filled twice: the initial inventory before winter and one replenishment during winter.

**Graph does not include the Mystic 8 and 9 gas-fired generators' fuel use or supply from the LNG facility.

***LDC use includes the Maritimes' gas utility demand. LDC data are from ICF International, New England LDC Gas Demand Forecast Through 2030 (December 14, 2016, presentation to Planning Advisory Committee).

Single-Variable Scenarios

The results are summarized below for the eight favorable and unfavorable scenarios that changed just one variable. Each of the favorable and unfavorable scenarios increased or decreased one key variable from the reference case baseline. (The exceptions were retirements, which were never dropped below the reference case level of 1,500 MW; and renewables, which never dropped below 6,600 MW, and in the case of higher renewables, was assigned a higher level of imports to reflect clean energy imports over a new transmission line.)

The study also included a best-case scenario (*High Boundary*), where all five variables were modeled at levels that would minimize fuel-security risk, and a worst-case scenario (*Low Boundary*) in which all five variables were modeled at less favorable levels that would raise fuel-security risk. At opposite ends of the spectrum, these two cases illustrated the best and worst outcomes but represent future resource combinations that are highly unlikely to materialize. Because they are considered unlikely scenarios, the results of these scenarios are not included in charts but are detailed in the matrix in Appendix A.

The single-variable scenarios with favorable inputs required from 0 to 7 hours of load shedding. The negative, single-variable scenarios, with the least favorable inputs, required load shedding ranging from 33 to 105 hours.

Figure 6 illustrates the range of OP 4 emergency-procedure hours resulting from each of the "plus" (favorable level) and "minus" (unfavorable level) single-variable cases. Figure 7 shows the range of OP 7 emergency-procedure hours for the single-variable cases.

Levels of Five Variables Are Key to Fuel-Security Risk

The single-variable cases explore the range of impacts of each of the five individual variables studied, as illustrated by these graphs. Each bar spans a variable's results from a high amount (⊕) through the reference case level (➔) and down to a low amount (⊖). Results in the first graph are measured in OP 4 emergency-action hours, which are an indicator of system stress and may involve public pleas for energy conservation. In the second graph, results are measured in OP 7 hours, which represent load shedding. Compared with the reference case, increased inputs lead to decreased risk – and vice versa (with the exception of retirements because more retirements lead to increased risk). No single variable eliminated all risk. Notably, decreases in each variable had proportionally greater negative effects, despite being of comparable value to the increases. The region's vulnerability to resource retirements and decreases in LNG availability is particularly evident.

Figure 6: Ranges of OP 4 Hours in Single-Variable Cases

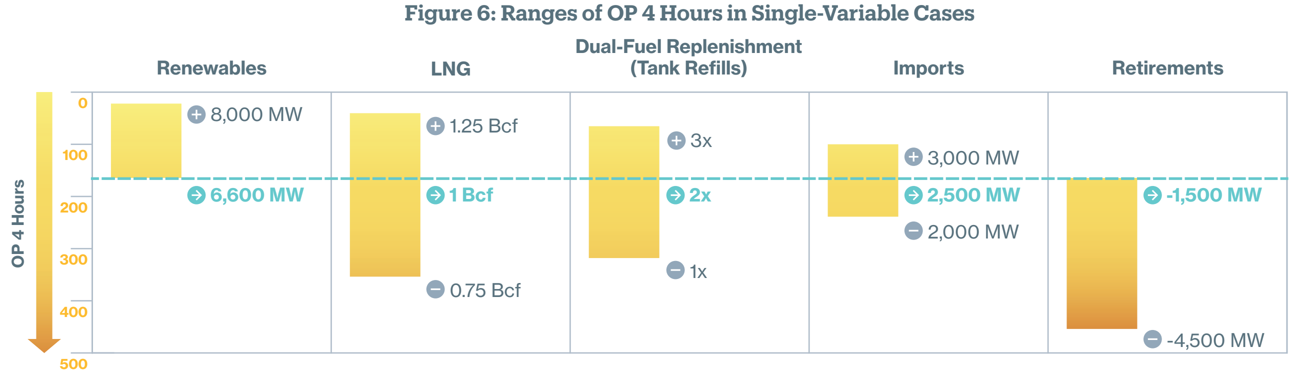
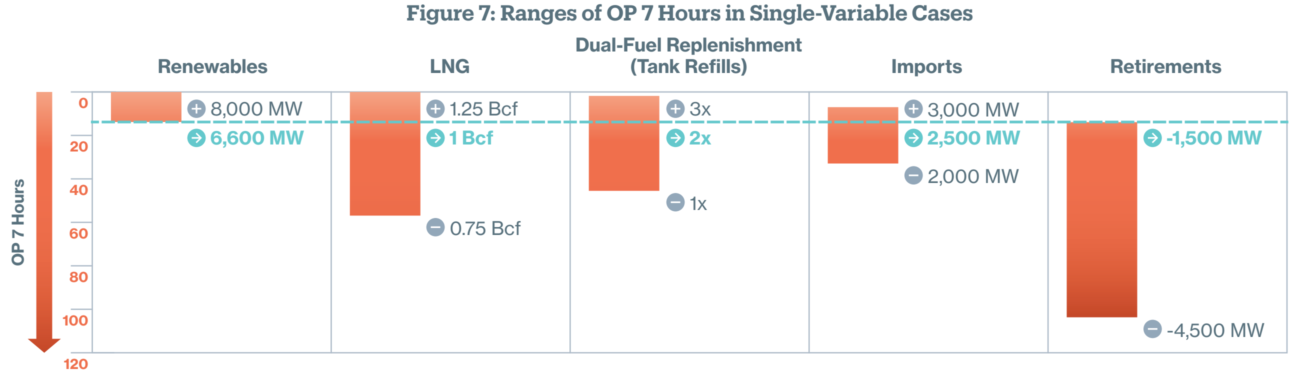


Figure 7: Ranges of OP 7 Hours in Single-Variable Cases



Range of OP 4 Hours Spanning Plus and Minus Cases
Range of OP 7 Hours Spanning Plus and Minus Cases
⊕ High-Case Input Value
⊖ Low-Case Input Value
– – Reference Case Hours
➔ Reference Case Input Values

Note: See Appendix A for more details.

Renewable Resources

As shown in Table 4, no load shedding was required for the positive, single-variable scenario that increased renewables to 8,000 MW and imports to 3,500 MW (to represent an additional 1,000 MW of clean energy over a new transmission tie to a neighboring system).

The high-renewables scenario resulted in 29 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used, and the scenario required 54.6 Bcf total LNG injections over the entire winter.

Table 4: Assumptions and Results for the Scenario with More Renewables Compared with the Reference Case

						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)
More Renewables	–1,500	1.00	2	3,500	8,000	29	24	6	2	0	0
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6

LNG

The favorable single-variable scenario raised LNG injections to 1.25 Bcf/d, which equals the highest daily LNG injection seen at any one time in the last nine years. This scenario required no load shedding (refer to Table 5). The unfavorable LNG scenario posited a maximum injection of 0.75 Bcf/d. The lower LNG injections required 58 hours of load shedding over 10 days.

The high LNG scenario resulted in 32 days when at least 95% of the assumed maximum LNG injection of 1.25 Bcf/d was being used. Over the entire winter in this scenario, 71 Bcf of LNG was used in New England. The low LNG scenario resulted in 39 days when at least 95% of the assumed maximum of 0.75 Bcf/d LNG was injected, and the region used 52.4 Bcf of LNG over the entire winter.

Table 5: Assumptions and Results for the Scenarios with More and Less LNG Compared with the Reference Case

						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)
More LNG	–1,500	1.25	2	2,500	6,600	32	40	9	6	0	0
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Less LNG	–1,500	0.75	2	2,500	6,600	39	355	208	153	58	10

Imports

Table 6 shows the results for the scenarios with more or less imports. The favorable single-variable scenario that raised imports to 3,000 MW, a level that was seen just 35% of the time during the winter period over the past five years, required 7 hours of load shedding over 4 days. The case that reduced imports to 2,000 MW, the level of imports seen on most days over the last five winters, required 33 hours of load shedding over 7 days.

The high-imports scenario resulted in 35 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used, with 60 Bcf/d imported for the winter. The low-imports scenario resulted in 36 days when at least 95% of the LNG was being used, up to the assumed maximum of 1 Bcf/d, and the region used 64.8 Bcf/d over the 90 days of winter.

Table 6: Assumptions and Results for the Scenarios with More and Less Imports Compared with the Reference Case

						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)
More Imports	–1,500	1.00	2	3,000	6,600	35	103	43	28	7	4
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Less Imports	–1,500	1.00	2	2,000	6,600	36	239	120	87	33	7

Dual-Fuel Replenishment

The scenario that increased the number of times dual-fuel generators' oil tanks were filled to three times during the winter—which would theoretically max out most generators' 30-day limit for running on oil—showed just one hour of load shedding on one day. The scenario that lowered the number of times oil tanks were filled to just once during the winter showed 46 hours of load shedding over 10 days. Refer to Table 7.

Both the high-oil-tank and low-oil-tank inventories scenarios resulted in 35 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. Both the high-oil and low-oil inventories scenarios used 62.4 Bcf total LNG over the course of the winter.

Table 7: Assumptions and Results for the Scenarios with More and Less Dual-Fuel Replenishment Compared with the Reference Case

						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)
More Dual-Fuel Replenishment	–1,500	1.00	3	2,500	6,600	35	69	26	13	1	1
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Less Dual-Fuel Replenishment	–1,500	1.00	1	2,500	6,600	35	317	173	115	46	10

Retirements

The unfavorable single-variable scenario that increased coal- and oil-fired power plant retirements to 4,500 MW had the worst outcomes among the single-variable cases: 105 hours of load shedding over 16 days, and 455 hours of all OP 4 actions as well as the depletion of 10-minute reserves during 258 hours of those OP 4 hours. The high-retirements scenario resulted in 35 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used, and the region used 62.4 Bcf/d over the winter. Table 8 summarizes the results for the high-retirements scenario.

Table 8: Assumptions and Results for the Scenario with More Retirements Compared with the Reference Case

						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)
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
More Retirements	–4,500	1.00	2	2,500	6,600	35	455	316	258	105	16

Combination Scenarios

The four combination cases each altered several variables at one time to develop a combination of future resource mixes that reflect several possible future power systems. All these cases included higher levels of renewables, which could be considered a proxy for greater levels of EE that reduce consumer demand for power; adding renewables would reduce the need to turn to stored fuels.

All the combination cases also added 1,000 MW to imports to bring the total to 3,500 MW. By increasing imports by 1,000 MW, these scenarios account for the Massachusetts requirement for about 1,200 MW of clean energy, such as hydro or wind energy imported from Canada or New York over a new high-voltage transmission line. All the combination cases also assumed oil tanks were filled twice during the winter.

Combination LNG Scenarios (High LNG and Low LNG with High Renewables/Higher Retirements)[43]

Two combination cases included high levels of renewables, at 8,000 MW, with imports at 3,500 MW, and higher levels of retirements, at 4,000 MW, with one case reducing LNG injections to 0.75 Bcf/d and the other increasing LNG injections to 1.25 Bcf/d. As shown in Table 9, the combination case with higher LNG injections showed no load shedding, while the combination case with low LNG injections resulted in 56 hours of load shedding over 12 days.

43. The case names refer to the labels included on the detailed results matrix in Appendix A as well as the smaller tables included with the scenario results in the body of the report.

The high LNG combination scenario showed total LNG injections of 61.6 Bcf and resulted in 23 days when at least 95% of the assumed maximum of 1.25 Bcf/d LNG was being used. The low LNG injections scenario resulted in total LNG consumption of 46.3 Bcf over the winter and 35 days when at least 95% of the assumed maximum of 0.75 Bcf/d LNG was being used.

Table 9: Assumptions and Results for the Combination LNG Scenarios Compared with the Reference Case

						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)
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
High LNG/ High Renewables/ Higher Retirements	–4,000	1.25	2	3,500	8,000	23	18	4	2	0	0
Low LNG/ High Renewables/ Higher Retirements	–4,000	0.75	2	3,500	8,000	35	358	200	154	56	12

Combination Scenario with High Retirements (High Renewables/High Retirements)

The third combination scenario doubled the reference case retirements of non-gas-fired units to 3,000 MW. The scenario also set renewables and imports to 8,000 MW and 3,500 MW, respectively, and held the maximum LNG injections level with the reference case at 1 Bcf/d. With high retirements, renewables, and imports, the third combination case resulted in just 2 hours of load shedding on one day. This scenario also resulted in total LNG injections of 54.6 Bcf over the winter and 29 days when at least 95% of the assumed maximum of 1 Bcf/d LNG was being used. Table 10 shows these results.

Table 10: Assumptions and Results for the Combination Scenario with High Retirements Compared with the Reference Case

						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)
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
High Renewables/ High Retirements	–3,000	1.00	2	3,500	8,000	29	84	25	17	2	1

Combination Scenario with Maximum Renewables and Maximum Retirements (Max Renewables/Max Retirements, or Max)

The fourth combination scenario assumed that the region's entire fleet of coal- and oil-fired generators had retired, totaling 5,400 MW. The case also assumed that the region's fleet of renewables had grown to 9,500 MW, the maximum level used in the study. This scenario added about 900 MW to the PV forecast, bringing the total PV to 5,300 MW. The projected level of offshore wind was increased by another 400 MW above the 1,600 MW offshore wind requirements of the Massachusetts energy legislation, to 2,000 MW. This scenario also increased imports to 3,500 MW, incorporating 1,000 MW of clean energy imported from neighboring systems.

This scenario could be considered akin to the effects of implementing strict carbon reduction goals or using other regulations to significantly limit carbon emissions from power plants. Carbon-reduction initiatives would attract higher levels of renewables and drive more fossil-fuel-fired generators to retirement.

In the scenario, with high retirements and high renewables, 15 hours of load shedding over 6 days was needed, and 52.9 Bcf of LNG was required over the winter, resulting in 23 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. Refer to Table 11.

Table 11: Assumptions and Results for the Combination Scenario with Maximum Retirements and Renewables Compared with the Reference Case

						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)
Reference Case	–1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Max Renewables/ Max Retirements (Max)	–5,400	1.00	2	3,500	9,500	23	206	94	64	15	6

Outage Scenarios

Eight outage scenarios show the consequences of four possible high-impact events involving the outages of important energy facilities for an entire winter. Outages of shorter duration would also create significant system stress and could require the implementation of emergency actions. Each of the outages was modeled twice: on a system represented by the reference case (*Ref*) and on a system represented by the combination case that includes the maximum levels of retirements and renewables assumed in the study (*Max Renewables/Max Retirements [Max]*).

The winter-long outages of the following facilities were modeled:

- A compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and restricting fuel to about 7,000 MW of generation for the entire winter
- The loss of Millstone Nuclear Power Station in Connecticut, one of the region's remaining two nuclear stations, eliminating 2,100 MW of baseload power
- The loss of the Canaport LNG import and regasification facility in New Brunswick, eliminating as much as 1.2 Bcf/d that could be injected into the New England and Maritimes pipeline systems
- A disruption to the Distrigas LNG import facility in Massachusetts, eliminating all the natural gas that can fuel the nearby, 1,700 MW Mystic 8 and 9 gas-fired generators, as well as 0.435 Bcf/d that can be injected by Distrigas into the Algonquin and Tennessee interstate gas pipeline systems and the local gas utility's distribution system

Figure 8 shows the projected hours of load shedding resulting from a season-long outage of a major fuel or energy source in the reference and *Max* cases.

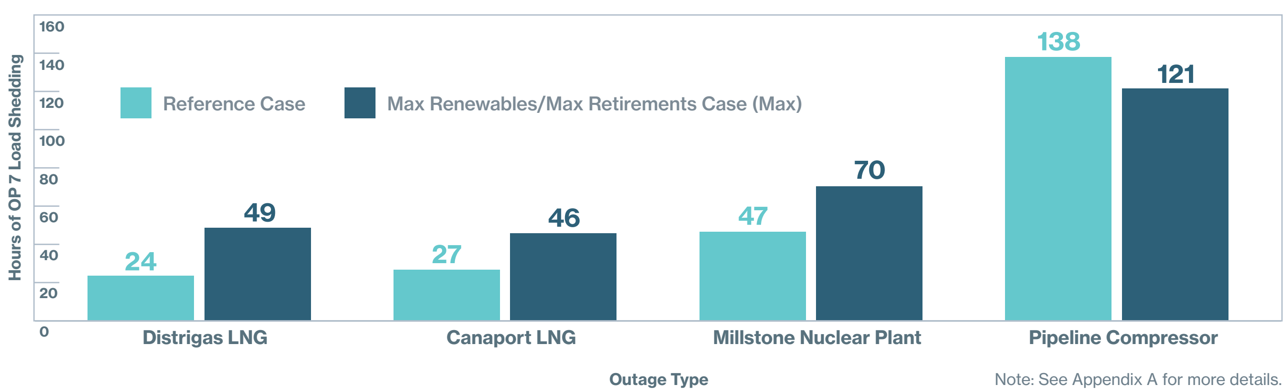
Some variables in the reference and *Max* cases were adjusted to reflect the expected consequences of each outage. For example, the reference case assumes that 1 Bcf/d would be the maximum LNG injection available on any given day. But if a compressor station went out for the entire winter, natural gas prices would rise and LNG suppliers would be expected to ship more LNG to New England. Similarly, higher natural gas prices mean higher wholesale electricity prices in New England, so dual-fuel generators could be expected to fill their tanks more often to ensure they would have fuel to run when prices were high.

High Levels of LNG, Oil, Imports, and Renewables Would Not Eliminate Load Shedding if a Major Energy Facility Goes Out

This graph shows the projected hours of load shedding (i.e., OP 7) that would result from the season-long loss of the Distrigas LNG terminal, Canaport LNG terminal, the Millstone nuclear plant, or an interstate pipeline compressor station. The study looked at the impacts of each of these outages in both the reference case and Max case, with the highest amount of renewables and retirements. It is worth noting that even the most aggressive increases in LNG, oil, and renewables would not prevent the need for load shedding, particularly during a pipeline compressor station outage. These winter-long outage scenarios also hint at the severe impact of a shorter-term outage, which would provide less time for the markets to mobilize other fuel or energy sources.

Figure 8: Projected Hours of Load Shedding due to Season-Long Outage of a Major Fuel or Energy Source

(Reference Case Compared with the Max Scenario)



Note: See Appendix A for more details.

Compressor Outage

As outlined above, the winter-long loss of a natural gas pipeline compressor station would likely spur higher imports of LNG and more frequent oil tank refills. Taking that into account, the maximum LNG injection assumed in both the reference and combination scenarios was increased from 1 Bcf/d to 1.5 Bcf/d, higher than the highest coincident injection of 1.25 Bcf/d seen on any one day in the region. These scenarios also assumed oil tanks were filled three times, rather than twice. Even with additional LNG and oil, the compressor station outage in the reference case (*Compressor Outage: Ref*) would have the highest number of load-shedding hours (apart from the unlikely worst-case scenario), at 138 hours over 17 days. On a power system represented by the scenario with the maximum level of retirements and renewables (*Compressor Outage: Max*), 121 load-shedding hours over 19 days would be needed. Table 12 shows the assumptions and results for this scenario.

Over 17 days, 138 hours of load shedding would equate to about eight hours per day, though given the variations in system conditions from day to day and hour to hour, such an even distribution of load shedding would be unlikely. Some days would have less than eight hours of load shedding; some would have more.

The compressor station outage in the reference case resulted in 127.8 Bcf of total LNG injections over the winter, while the outage in the combination scenario required 112.2 Bcf. Both are far higher than the highest level of LNG delivered to New England pipelines, which was 73 Bcf in winter 2010/2011. The reference case and combination cases resulted in 47 days and 41 days, respectively, when at least 95% of the assumed maximum daily LNG injection of 1.5 Bcf/d was being used.

As these results illustrate, a pipeline compressor outage would have a significant impact on New England's power system because of the region's limited network of pipelines; most or all the limited natural gas that could get into New England would go to gas utilities serving their heating customers.

Table 12: Assumptions and Results for the Pipeline Compressor Outage Scenarios

						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)
Compressor Outage: Ref	–1,500	1.50	3	2,500	6,600	47	458	290	252	138	17
Compressor Outage: Max	–5,400	1.50	3	3,500	9,500	41	510	340	273	121	19

Millstone Nuclear Outage

The winter-long outage of a nuclear power station was incorporated into the hourly dispatch employed by the study model, rather than represented as an input variable. The model assumed that Millstone, a 2,100 MW nuclear power plant, which would usually be among the first resources dispatched every day, would not be available for the entire winter. Without this baseload resource, more resources using other fuels, including natural gas, oil, and LNG, would be needed more often, depleting their fuel sources. In the reference case, the nuclear outage (*Millstone Nuclear Outage: Ref*) would require 47 hours of load shedding over 10 days. Refer to Table 13.

In the nuclear outage case with maximum retirements and maximum renewables (*Millstone Nuclear Outage: Max*), more renewables would help when available, but the absence of all coal- and oil-fired generators coupled with the nuclear outage would mean virtually all the power plants with stored fuel in New England would be unavailable. The result would be 70 hours of load shedding over 12 days.

The Millstone reference case outage resulted in 72.9 Bcf total LNG injections over the winter – about the same as the most wintertime LNG deliveries seen to date – and 42 days when at least 95% of the assumed maximum daily LNG injection of 1 Bcf/d was being used. The nuclear combination case outage resulted in total LNG injections of 61.6 Bcf over the winter, and 36 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used.

Table 13: Assumptions and Results for the Millstone Nuclear Outage Scenarios

						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)
Millstone Nuclear Outage: Ref	–1,500	1.00	3	2,500	6,600	42	349	166	124	47	10
Millstone Nuclear Outage: Max	–5,400	1.00	3	3,500	9,500	36	389	243	193	70	12

Distrigas LNG and Mystic 8 and 9 Outage

On a power system represented by the reference case, the outage of Distrigas, one of the region's three LNG import facilities and the nearby Mystic 8 and 9 generating units fueled by that imported LNG, would cause 24 hours of load shedding over seven days (*Distrigas LNG Outage: Ref*), as shown in Table 14. If the outage occurred on a system with maximum retirements and maximum renewables, twice as many load shedding hours would be required, at 49 hours over 11 days (*Distrigas LNG Outage: Max*).

The Distrigas outage in the reference scenario resulted in 50.9 Bcf total LNG injections over the winter, and 41 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. The *Distrigas LNG Outage: Max* scenario resulted in total LNG injections of 43.8 Bcf over the winter, and 34 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. While this scenario assumed that the Distrigas LNG import facility would be out of service during the entire winter, maximum LNG injections were not reduced below 1 Bcf/d because it was assumed the region's other two LNG facilities would increase their imports.

Table 14: Assumptions and Results for the Distrigas and Mystic 8 and 9 Outage Scenarios

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT					
						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)
Distrigas LNG Outage: Ref	–1,500	1.00	3	2,500	6,600	41	276	114	87	24	7
Distrigas LNG Outage: Max	–5,400	1.00	3	3,500	9,500	34	346	181	142	49	11

Canaport LNG Terminal Outage

The season-long outage of the large Canaport LNG import facility in Canada would reduce the LNG available to inject into New England's pipeline system. The study reflects this by reducing LNG injections to 0.65 Bcf/d, the lowest level assumed in any scenario. In the reference case, the outage would cause load to be shed 27 hours over nine days (*Canaport LNG Outage: Ref*). In the scenario with maximum retirements and maximum renewables, the outage would require 46 hours of load shedding over 11 days (*Canaport LNG Outage: Max*). Refer to Table 15.

The Canaport LNG import facility outage in the reference scenario resulted in 48.1 Bcf total LNG injections over the winter, and 41 days when at least 95% of the assumed maximum LNG injection of 0.65 Bcf/d was being used. The *Canaport LNG Outage: Max* resulted in 41.4 Bcf total LNG injections over the winter and 35 days when at least 95% of the assumed maximum LNG injection of 0.65 Bcf/d was being used.

Table 15: Assumptions and Results for the Canaport LNG Outage Scenarios

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT					
						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)
Canaport LNG Outage: Ref	–1,500	0.65	3	2,500	6,600	41	270	129	90	27	9
Canaport LNG Outage: Max	–5,400	0.65	3	3,500	9,500	35	354	187	134	46	11

Key Findings

Key findings from the report include:

- **All four outage scenarios** involving the winter-long loss of key energy facilities produced the most severe outcomes, illustrating the region's vulnerability to these sources. Each outage of a natural gas pipeline compressor station, a nuclear station, or one of the region's LNG import facilities resulted in hundreds of hours of operating procedures and emergency actions and between two dozen and more than 100 hours of load shedding. The loss of a compressor station was particularly problematic, given the resulting reduction in natural gas supply in New England. The local gas utilities would fully use their firm capacity rights on other pipelines and secure priority rights to the region's LNG facilities for many more hours. This would further reduce the natural gas available to power plants, with the results showing more than 120 hours of load shedding spread across 19 days.
- **Two combination cases *(High LNG/High Renewables/Higher Retirements* and *High Renewables/High Retirements)*** showed that higher levels of retirements of oil- and coal-fired power plants could be addressed with higher levels of LNG, imports, and renewables, resulting in fewer hours of emergency actions, less need to deplete operating reserves, and very limited exposure to load shedding. These cases' inputs fall in the range between the reference case and the scenario with maximum retirements and maximum renewables, indicating that the power system can be expected to remain extremely vulnerable to the outages of any of the region's key energy suppliers.
- **A combination case *(Low LNG/High Renewables/Higher Retirements)*** with a high level of retirements of non-gas-fired generators coupled with lower LNG injections required frequent emergency actions and multiple hours of load shedding, despite higher levels of imports and renewables.
- **The combination case *(Max Renewables/Max Retirements)*** with maximum retirements and maximum renewables illustrated the impacts of retiring every at-risk coal- and oil-fired generator in the region and developing the highest level of renewable resources. With moderate levels of LNG, imports, and oil tank inventories, more than 200 hours of emergency actions and more than a dozen hours of load shedding over six days were required to maintain system balance. The outage scenarios based on this combination case demonstrated that the loss of a key energy facility would exacerbate the use of emergency procedures.

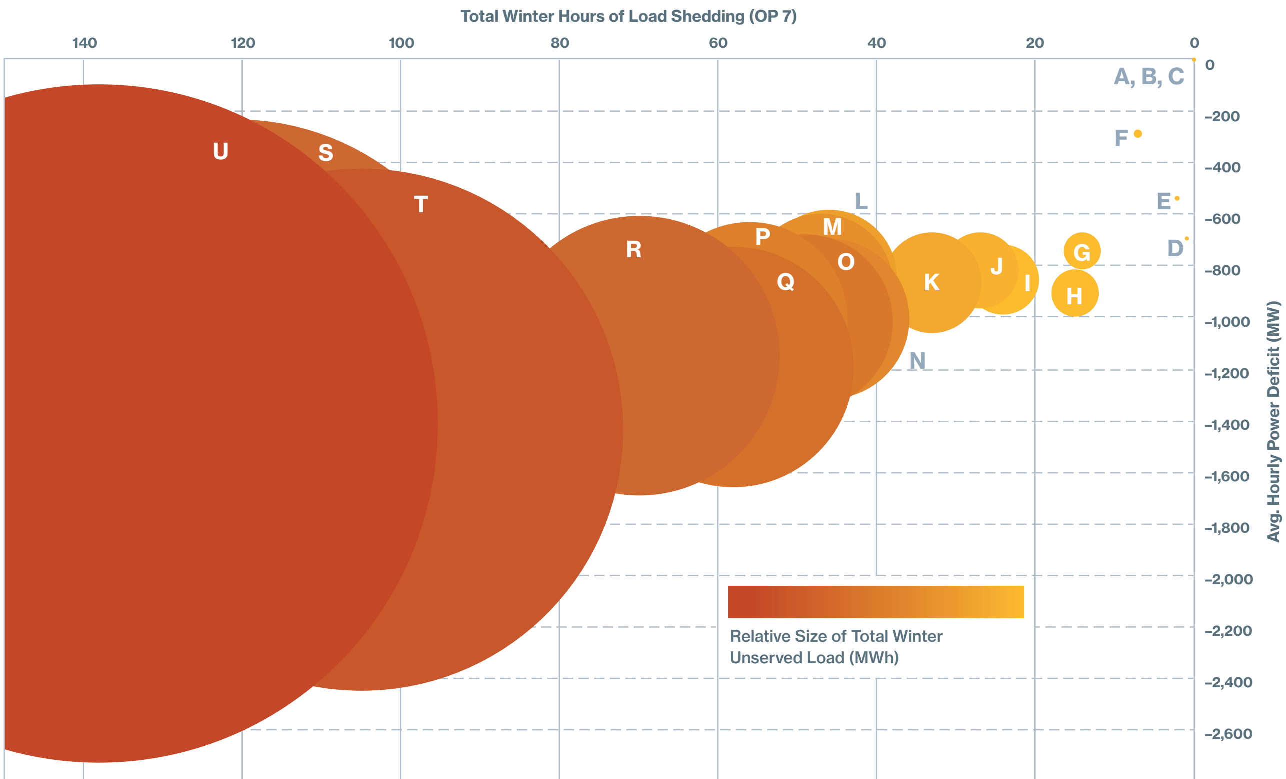
- **The single-variable cases** that raised or lowered just one variable showed the following:
  - **The retirements of oil- and coal-fired power plants** have the greatest impact among the five variables on increasing the region's fuel-security risk, as measured by the frequency and duration of energy shortfalls requiring emergency actions. The scenarios that raised the level of retirements saw a seven-fold increase in OP 7 hours over the reference case. Other negative variables increased load shedding to no more than four times the reference case level.
  - **Lower LNG injections** have the next-greatest impact on increasing the region's fuel-security risk**,** increasing load shedding to nearly 60 hours compared with 14 hours in the reference case. **Conversely, higher LNG injections** have a significant impact on reducing the region's fuel-security risk – the higher LNG case had no load shedding and far fewer hours of emergency actions.
  - **Increased oil inventories at dual-fuel generators** also significantly improve fuel security. The single-variable scenario that increased the number of times dual-fuel power plants could replenish their oil inventory showed relatively lower levels of system stress, including just one hour of load shedding.
  - **Large amounts of renewable resources combined with additional imports** lowered the fuel-security risk compared with the reference case, with no load shedding and a greatly reduced need for emergency actions.
- **The two boundary cases that moved all variables in either the most favorable or least favorable direction** showed the most positive or negative results, as would be expected. But each of the boundary scenarios would require all five variables to evolve in the same direction, which is unlikely.

Figure 9 reflects the magnitude of load shedding (i.e., OP 7) in all but the high and low boundary scenarios, with the bubble size depicting the total projected megawatt-hours (MWh) of unserved load. One megawatt-hour is the amount of energy produced by 1 MW over one hour. A power resource of 500 MW capacity, for example, will provide 1,000 MWh of energy if it operates at this capacity for two hours. In New England, 1 MWh can serve the equivalent of approximately 860 homes for one hour, on average. This study assumed New England would have sufficient resource *capacity* (megawatts) to meet future demand in winter 2024/2025, and instead focused on the ability of that capacity to generate *energy* over time (megawatt-hours). Megawatt-hours of energy shortfalls – or unserved load – demonstrate how fuel availability can ultimately determine a resource's actual output over the course of an entire winter, regardless of its capacity.

The Greatest Risks Come from Major Outages, More Retirements, and Lower LNG and Oil Supplies

This chart reflects the magnitude of load shedding (i.e., OP 7) in each of the scenarios. (The high and low boundary cases were omitted.) The bubble size represents the total megawatt-hours of load shedding for the winter, illustrating the region's vulnerability to outages of major energy facilities, increases in retirements, and drops in LNG or oil supplies.

Figure 9: Magnitude of Load Shedding in Modeled Cases



Cases Ordered by Total Winter Unserved Load (MWh), Least to Most:

Case	MWh	Case	MWh	Case	MWh
A) High LNG/High Renewables/ Higher Retirements C	0	H) Max Renewables/ Max Retirements (Max) C	13,609	O) Distrigas LNG Outage: Max O	49,805
B) More Renewables S	0	I) Distrigas LNG Outage: Ref O	20,496	P) Low LNG/High Renewables/ Higher Retirements C	56,518
C) More LNG S	0	J) Canaport LNG Outage: Ref O	22,026	Q) Less LNG S	69,179
D) More Dual-Fuel Replenishment S	696	K) Less Imports S	28,608	R) Millstone Nuclear Outage: Max O	80,312
E) High Renewables/ High Retirements C	1,070	L) Canaport LNG Outage: Max O	38,819	S) Compressor Outage: Max O	149,574
F) More Imports S	2,031	M) Millstone Nuclear Outage: Ref O	41,080	T) More Retirements S	150,297
G) Reference Case	10,397	N) Less Dual-Fuel Replenishment S	46,232	U) Compressor Outage: Ref O	194,705

S Single-Variable Cases C Combination Cases O Outage Cases

Note: See Appendix A for more details.

Conclusions

For New England, the foremost risk to current and future power system reliability revolves around fuel security—the ability of power plants to get the fuel they need to run, when they need it.

This operational fuel-security assessment has quantified the level of risk in a wide range of possible future resource combinations and provides information the region can use to consider approaches to ensuring power system reliability. The diversity of scenarios was designed to help ISO New England and its stakeholders better understand how well these future power system profiles, or other profiles that fall between them, could support power system reliability throughout an entire winter.

The study results indicate the risk of future energy shortfalls is greater than the risk today. All but one of the 23 scenarios show that the regional power system could frequently experience some degree of system stress, requiring system operators to employ emergency procedures. All but four scenarios show that some level of load shedding would be needed to maintain system balance. This indicates that the region is currently maintaining a delicate balance that could easily be disrupted if any of the five key variables—retirements of coal- and oil-fired generators, LNG injection levels, the availability of oil as well as the permitted ability to burn oil, electricity imports, and the development of renewable resources—trend in a negative direction at an accelerated rate.

This fuel-security analysis also illustrates the acute vulnerability of New England's power system to the loss of any one of several key energy facilities. The region is particularly vulnerable to an outage at a natural gas pipeline compressor station.

Outages

The regional dependency on several key facilities is a particular concern highlighted by this study. An extended outage at any one of these key facilities—a natural gas pipeline compressor station, the Distrigas LNG import facility in Massachusetts and the Mystic 8 and 9 generators it fuels, the Canaport LNG import facility in Canada, or the Millstone nuclear power plant—would result in frequent energy shortages that would require frequent and long periods of rolling blackouts.[44] While outages of shorter duration were not studied, the importance of these facilities to system reliability is highlighted by the results of this fuel-security study. An outage at any of these facilities, regardless of duration, would likely create significant system stress.

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44. Potomac Economics *2016 Assessment of the ISO New England Electricity Markets*, report of the ISO New England external market monitor (June 2017), p.22, https://www.iso-ne.com/static-assets/documents/2017/08/iso-ne-2016-som-report-full-report-final.pdf. "In the Baseline scenarios shown in Figure 7, LNG capacity would become pivotal for meeting generators' demand in 2023/24, even if the oil storage is fully utilized."

The reliability impact of any one of these outages cannot be eliminated, even on a system with more LNG, oil inventory, and imports, the study shows. Each outage scenario would require load shedding that could affect hundreds of thousands of average New England homes at a time.

A compressor station outage on a major natural gas pipeline would have the most severe impact on power system reliability, requiring the most frequent and extensive load shedding of all the scenarios, aside from the unlikely negative boundary scenario. Frequent load shedding would be required even in a scenario with the likely increase in imports of LNG and electricity, as well as greater use of oil inventories by dual-fuel power plants and very high levels of renewable resources.

The ISO's ability to address this high-impact scenario is limited to designing operational procedures to ensure that if such a compressor station or pipeline outage occurs, system stability can be maintained and cascading outages are prevented. The impact of such an outage can be mitigated through the use of increased LNG and imported electricity, as well as greater renewable resources and dual-fuel capacity with enhanced strategies for replenishing oil tank inventories.

Stored Fuels: Imported LNG, Electricity Imports, and Dual-Fuel Capability

The study illustrates that over the next several decades, New England's power system will largely depend on the availability of two key elements: sufficient injections of LNG and electricity imports from neighboring regions. However, the availability of LNG and imports may be subject to some forces that are outside the purview of ISO New England and New England's policymakers.

Additional dual-fuel capability, which will increase the inventory of stored oil available to generate electricity when other fuels are not available in sufficient quantities, would also provide a key contribution to power system reliability. However, state emissions requirements are tightening, which will limit the amount of time some generators can run on oil, and obtaining permits to construct new dual-fuel generators is becoming more difficult.

LNG injections from import terminals in the east and Canada have provided important supplements to pipeline gas and have helped support New England's power system reliability, but as demand for natural gas for heating rises and pipeline capacity remains the same, more local gas utilities are contracting for LNG to serve their customers. Further, as natural gas fields in Atlantic Canada are depleted, the Maritimes' demand for natural gas from pipelines and LNG import facilities is expected to rise. In the future, less LNG may be available for power plants in New England. But at the same time, the continuing retirements of oil- and coal-fired power plants, which use fuel stored on site, will increase New England's reliance on imported LNG.

Robust levels of imported electricity from neighboring power systems are essential to continued power system reliability. However, imports also present a degree of uncertainty and risk. Each scenario assumes a level of imports at least twice the amount obligated through the Forward Capacity Market.[45] In other words, half the imports assumed in the study may not be available if the neighboring area where they are located needs them. This is important because Québec, New York, and New Brunswick all experience winter weather at the same time as New England. The question is whether New England's neighbors will have enough electricity to serve their own customers and supply New England with all the electricity

45. Resources that clear in the annual Forward Capacity Market auction administered by ISO New England take on an obligation (called a capacity supply obligation, or CSO) to be available in the relevant capacity commitment period. In return, they receive a monthly payment based on the auction clearing price and the number of megawatts they promised to make available.

assumed in the scenarios. Also, New York and New Brunswick, as well as New England, all depend on imports from Québec. A power system contingency in Québec can deplete its exports and have a domino effect on its neighbors.[46]

Further, as New York's power system evolves away from oil-fired and nuclear plants with on-site fuel, and toward increased dependence on natural gas and renewables, the extent of the New York system's ability to support electricity exports to New England is unclear. Also unclear is whether this trend will reduce the availability of pipeline gas supplied to New England.

With the increasing retirements of generators with stored fuels (nuclear, coal, and oil), the region's reliance on imported fuels and electricity is likely to grow. Greater levels of dual-fuel capability, which would enable natural-gas-fired generators to turn to oil stored onsite when they can't get gas, helps system reliability.

Logistics

Some resource mixes pose less fuel-security risk than others, but all scenarios are subject to the unquantifiable uncertainties of fuel-delivery logistics, weather, and events that unfold on the power grid more randomly than can be represented in a study of this type.

Fuel-delivery logistics are a factor in fuel-security risk. As winter progresses, the cumulative use of oil and LNG depletes power plants' inventories, requiring replenishment and heightening the importance of timely fuel deliveries. Refilling oil and LNG tanks at some point over the course of a 90-day winter is not the problem. But when winter storms and cold snaps follow on each other in quick succession, refilling fuel tanks quickly is of paramount importance. Timely replenishment can be challenging, however, because of the difficulty in predicting far enough in advance how much LNG or oil will be needed to ensure trucks and LNG tankers will arrive when needed.

The vagaries of weather, combined with restrictions on how often power plants can run on oil, compound the uncertainties of fuel-delivery logistics. Most power plants in New England are limited to operating on oil no more than 30 days per year. A cold December with limited availability of natural gas could cause a generator to not only deplete its fuel inventory but also reduce the days remaining that it can run on oil – with two months of winter left to go.

The study results highlight significant logistical questions that may have an impact on fuel adequacy for generators. For example, will ocean-going tankers of LNG, a global commodity, arrive in the northeast when needed? Will winter storms prevent oil trucks from delivering fuel to power plants? Will tanker trucks be unavailable because they are delivering oil first to heating customers? Will New England weather deliver a one-two punch of extreme cold followed by a severe storm, leaving more generators with depleted inventories and not enough time to get their tanks refilled, as happened in 2013?[47] And will neighboring power systems deliver the high levels of imports most of these scenarios count on, at a time when their own winter demand is peaking?

46. Jan Ellen Spiegel, "Canadian fires cause close call for New England power supply," CT Mirror (August 8, 2013), https://ctmirror.org/2013/08/08/canadian-fires-cause-close-call-new-england-power-supply/.

47. ISO New England, "New England grid operated reliably through 2012/2013 winter despite resource performance challenges" (ISO Newswire, March 27, 2013), http://isonewswire.com/updates/2013/3/27/new-england-grid-operated-reliably-through-20122013-winter-d.html.

ISO New England, "Winter Operations Summary: January–February 2013," draft paper (February 28, 2013), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb__27_draft_for_discussion.pdf.

Risk Trending in a Negative Direction

Current trends are pushing the New England power system on a path toward greater fuel-security risks. These trends include the increasing retirements of power plants with fuel stored onsite (nuclear, coal and oil); the growth in power plants dependent on natural gas, a fuel that's delivered just in time; growing demand for natural gas from local gas utilities in both New England and the Maritimes, which will likely leave less for power plants; and an increase in renewable resources with variable production.

This fuel-security analysis was conducted to quantify the potential operational impacts of these trends. The wide range of 23 hypothetical scenarios was designed to illustrate the potential outcomes from a variety of future power systems made up of different resource combinations, including more favorable as well as less favorable levels of each variable. The study incorporated expected levels of energy-efficiency measures into its demand forecast and included significant development of behind-the-meter solar, offshore wind, and additional imports.

Only four of the scenarios – including the positive boundary scenario, which is highly unlikely to materialize – had no load shedding and few emergency actions. And the study results clearly show that New England remains extremely vulnerable to the loss of any of the region's key energy facilities.

The reference case, which represents a future power system that could be expected to develop, required hundreds of hours of emergency actions and the depletion of reserves and more than a dozen hours of load shedding. These risks could be offset by additional LNG imports or more renewable energy. However, the addition of large quantities of low-cost renewable resources is expected to lower wholesale energy prices and drive additional non-gas-fired generators to retirement, thus exacerbating fuel-security risks.

On balance, the analysis revealed that fuel-security risks are present in the vast majority of cases, even in scenarios with higher LNG, renewables, and imports.

The wide range of scenarios provides not just clear illustrations of what would happen if the power system evolved as outlined in each scenario, but also allows for conclusions about the outcomes of intermediate levels of each variable.

More Renewables Help, but Don't Eliminate the Risk

Renewable resources can mitigate the region's fuel-security risk, and the study includes scenarios that incorporate all, and in some cases more than, the renewable resources that could result from existing or future clean energy initiatives of several New England states.

The growth of renewable resources, with their low operating costs, is likely to drive greater retirements of more costly, aging coal- and oil-fired power plants. Even when the retirements of these generators occurs in tandem with robust growth of renewable resources, the region's dependence on higher imports of LNG to counteract the loss of stored fuels is not erased.

Another factor is the timing of winter peak demand, which occurs after the sun has set. Solar arrays can help reduce consumption of oil and natural gas for power generation on sunny winter days, preserving more oil and gas to help meet peak demand. But solar PV itself does not help meet the daily winter peak in demand.

Energy from wind farms isn't always available when needed, though offshore wind tends to blow more steadily than onshore wind. Further, developing more onshore wind facilities in northern New England and importing more clean energy from neighboring systems will require significant investment in new transmission infrastructure.

Energy storage can help even out intermittent output from wind and solar resources and support system reliability, but cost-effective, utility-scale advanced energy storage is still being developed.

More Positive Outcomes

A resource mix with higher levels of LNG, imports, and renewables shows less system stress than the reference case. These scenarios, while based on resources dependent on uncontrollable factors – the global LNG market, the coincident winter demands of regions exporting power to New England, and weather – result in fewer hours of emergency actions, depletion of reserves, and load shedding. To achieve these levels of LNG, imports, and renewables, firm contracts for LNG delivery, assurances that electricity imports will be delivered in winter, and aggressive development of renewables, including expansion of the transmission system to import more clean energy from neighboring systems, would be required.

Next Steps

The ISO will discuss the results of this operational fuel-security analysis with stakeholders, regulators, and policymakers throughout 2018.

A key question to be addressed will be the level of fuel-security risk that the ISO, the region, and its policymakers and regulators are willing to tolerate. As the system operator mandated to maintain a reliable power system, the ISO must conduct its own assessment of the level of risk to reliable operations. A primary consideration will be ISO New England's responsibility, as a regional reliability coordinator, to operate the region's power system in a way that maintains the reliability of not only the region but also the entire Eastern Interconnection.

Discussions about possible solutions to the region's fuel-security risk are also expected to commence in 2018. The ISO will work with stakeholders to determine whether further operational or market design measures will be needed to address the fuel-security risks already confronting the New England power system and that may accelerate in the coming years.

Using the new model developed for this study, the ISO plans to conduct periodic operational assessments to re-evaluate the level of fuel-security risk presented by the resources available at the time. The ISO could also conduct additional analysis based on stakeholder feedback on the study results.

ROW		INPUTS					TOTAL WINTER IMPACT									
							OP 4 Actions			Depletion of 10-Minute Reserves[1]			OP 7 Action: Load Shedding			
							All OP 4 Actions	Actions 6-11								
	Reference Case (i.e., Current Trends) **and Single-Variable Cases**	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)[2]	Imports (MW)	Renewables (MW)[3]	Hours	Hours	Avg. Hourly Power Deficit (MW)[4]	Hours	Avg. Hourly Power Deficit (MW)[4]	Load at Risk (MWh)[5]	Hours	Avg. Hourly Power Deficit (MW)[4]	Unserved Load (MWh)[5]	Days with Load Shedding
1	High Boundary	–1,500	1.25	3	3,500	8,000	0	0	0	0	0	0	0	0	0	0
2	More Renewables	–1,500	1.00	2	3,500	8,000	24	6	408	2	765	1,530	0	0	0	0
3	More LNG	–1,500	1.25	2	2,500	6,600	40	9	440	6	545	3,272	0	0	0	0
4	More Dual-Fuel Replenishment	–1,500	1.00	3	2,500	6,600	69	26	319	13	609	7,913	1	696	696	1
5	More Imports	–1,500	1.00	2	3,000	6,600	103	43	404	28	816	22,859	7	290	2,031	4
6	**Reference Case (Ref)**	–1,500	1.00	2	2,500	6,600	165	76	419	53	980	51,963	14	743	10,397	6
7	Less Imports	–1,500	1.00	2	2,000	6,600	239	120	427	87	1,039	90,395	33	867	28,608	7
8	Less Dual-Fuel Replenishment	–1,500	1.00	1	2,500	6,600	317	173	410	115	1,079	124,045	46	1,005	46,232	10
9	Less LNG	–1,500	0.75	2	2,500	6,600	355	208	430	153	1,072	164,065	58	1,193	69,179	10
10	More Retirements	–4,500	1.00	2	2,500	6,600	455	316	454	258	1,078	278,135	105	1,431	150,297	16
11	Low Boundary	–4,500	0.75	1	2,000	6,600	811	692	480	642	1,394	895,145	475	2,080	987,872	31
	Combination Cases															
12	High Renewables/High Retirements	–3,000	1.00	2	3,500	8,000	84	25	373	17	760	12,918	2	535	1,070	1
13	High LNG/High Renewables/Higher Retirements	–4,000	1.25	2	3,500	8,000	18	4	405	2	500	1,000	0	0	0	0
14	Low LNG/High Renewables/Higher Retirements	–4,000	0.75	2	3,500	8,000	358	200	435	154	1,030	158,552	56	1,009	56,518	12
15	Max Renewables/Max Retirements (Max)	–5,400	1.00	2	3,500	9,500	206	94	408	64	934	59,790	15	907	13,609	6
	Outage Cases (Modeled on Ref and Max Cases; Assumed More Dual-Fuel Tank Fills)															
16	Distrigas LNG Outage: Ref[6]	–1,500	1.00	3	2,500	6,600	276	114	440	87	961	83,628	24	854	20,496	7
17	Distrigas LNG Outage: Max[6]	–5,400	1.00	3	3,500	9,500	346	181	442	142	971	137,814	49	1,016	49,805	11
18	Canaport LNG Outage: Ref[7]	–1,500	0.65	3	2,500	6,600	270	129	421	90	944	84,973	27	816	22,026	9
19	Canaport LNG Outage: Max[7]	–5,400	0.65	3	3,500	9,500	354	187	424	134	998	133,779	46	844	38,819	11
20	Millstone Nuclear Outage: Ref[8]	–1,500	1.00	3	2,500	6,600	349	166	433	124	1,015	125,852	47	874	41,080	10
21	Millstone Nuclear Outage: Max[8]	–5,400	1.00	3	3,500	9,500	389	243	450	193	1,012	195,358	70	1,147	80,312	12
22	Compressor Outage: Ref[9]	–1,500	1.50	3	2,500	6,600	458	290	468	252	1,231	310,163	138	1,411	194,705	17
23	Compressor Outage: Max[9]	–5,400	1.50	3	3,500	9,500	510	340	448	273	1,107	302,258	121	1,236	149,574	19

– Reference Case +

1. Once reserves are depleted, any resource loss or transmission line trip that cuts imports would trigger load shedding.
2. Count assumed tanks were filled before winter, plus refilled during winter. For example, "2x" counted the initial full tank, plus one refill.
3. Cases with increased renewables also included increased imports to reflect expected additions of clean energy imports from Canada or New York.
4. On average, one megawatt (MW) of electricity can serve about 860 homes in New England, which has about 7.1 million retail customers, encompassing not just residential customers but also commercial and industrial.
5. A megawatt-hour (MWh) of electricity can serve about 860 homes for one hour in New England, on average.
6. Case assumed a disruption to the Distrigas LNG import facility in Massachusetts, eliminating all the natural gas that can fuel the nearby, 1,700 MW Mystic 8 and 9 gas-fired generators, as well as 0.435 Bcf/d the LNG facility can inject into the Algonquin and Tennessee interstate gas pipeline systems (0.3 Bcf/d) and the local gas utility's distribution system (0.135 Bcf/d).
7. Case assumes the loss of Canaport, the major LNG import facility in New Brunswick, Canada, eliminating as much as 1.2 Bcf/d that could be injected into the New England and Maritimes pipeline systems.
8. Case assumes the loss of Millstone, one of the region's remaining two nuclear power plants, eliminating 2,100 MW of baseload power.
9. Case assumes the loss of a compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and cutting off fuel for the entire winter to generators with a combined capacity of about 7,000 MW.