UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New England Winter Gas-Electric Forum	**)**	**Docket No. AD22-9-000**

POST-TECHNICAL CONFERENCE COMMENTS OF POTOMAC ECONOMICS, LTD.

Potomac Economics participated in the New England Winter Gas-Electric Forum on September 8, 2022, on winter reliability issues in New England during periods of limited natural gas supplies. Potomac Economics appreciated the opportunity to participate in the Forum and respectfully submits these comments addressing the concerns raised in the Forum. Potomac Economics serves as the External Market Monitor for ISO-NE.

I. INTRODUCTION AND SUMMARY

Stakeholders and the Commission have grown increasingly concerned about the risk of winter energy shortages in New England due to inadequate fuel supplies. The electric system is particularly vulnerable because it relies heavily on gas-fired generators that may be unable to obtain gas from interstate pipelines during extreme cold conditions. In recent years, the region has relied on imports of LNG to supplement pipeline gas supplies, but the supply of LNG imports is likely to fall due to global market conditions and the planned retirement of the Mystic 8 and 9 generating units.

In these comments, we demonstrate that ISO-NE has sufficient fuel-secure generation capacity to maintain reliability in the winter with only modest levels of LNG imports. The primary factor affecting reliability will be the management of oil inventories by the region's 12 GW of oil-fired and dual-fuel generating capacity, which have entered recent winters with their tanks only half full and done limited refueling during the winter. The region's three LNG import facilities have more than enough capability to inject gas into the pipeline system, but LNG imports are generally not available to power plants that do not contract for deliveries in advance of the winter.

Simply put, oil units do not maximize their inventories and gas units rarely contract for LNG primarily because ISO-NE's markets do not generally give them adequate incentives to do so. The current mix of market incentives from the day-ahead and real-time markets, together with the Pay-For-Performance framework, motivate generators to maintain adequate inventories to satisfy system requirements under a *likely* set of winter weather conditions. However, to motivate generators to maintain adequate fuel supplies for *extreme* winter weather, we recommend: a) considering winter fuel availability in ISO-NE's resource adequacy model, and b) accrediting capacity suppliers based on their marginal contribution to winter reliability. This will cause capacity prices to rise when winter reliability risks are high (whether due to a lack of peak generating capacity or a lack of seasonal 'energy adequacy'). It will also differentiate payments to oil and gas units based on their ability to obtain firm fuel or maintain on-site inventories. This approach fits within the general framework of capacity accreditation enhancements that ISO-NE is already pursuing for other resource types.[1]

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1 See ISO-NE October 18, 2022, Markets Committee presentation, "Resource Capacity Accreditation in the Forward Capacity Market".

Our proposed approach would provide financial incentives for resource owners to pursue the most cost-effective options for improving their contributions to winter reliability. The approach would procure enough fuel-secure resources to satisfy winter planning requirements. For most units, this would simply entail fuller utilization of existing oil inventories. However, this could also motivate investment in additional on-site fuel storage at some locations or in new resources that make significant contributions to winter reliability. Hence, ISO-NE should improve its resource adequacy modeling and capacity accreditation for limited-inventory oil resources alongside its current plans to consider gas pipeline limitations.[2] We recommend that the Commission refrain from issuing orders that would allow out-of-market procurement of a subset of fuel-secure resources in a discriminatory fashion because it would undermine incentives for investment in competing resources that contribute to winter reliability.

The development of a capacity market solution to address winter reliability is complicated by the three-year forward auction and the deteriorating winter reliability situation over the next few years. The contract for the Mystic 8 and 9 units extends through the 2023/24 winter, while the Inventoried Energy Program ("IEP") will be in effect for the 2023/24 and 2024/25 winters. However, both measures are scheduled to end before 2025/26, and the upcoming FCA in February 2023 will procure capacity for the 2026/27 winter with no consideration of whether resources provide any winter reliability value. To address these issues, we have recommended that ISO-NE transition to a prompt seasonal capacity market.[3] To facilitate this transition, we recommend delaying the next few FCAs until closer to their respective capacity delivery periods.

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2 See ISO-NE October 18, 2022, Markets Committee presentation, "Resource Capacity Accreditation in the Forward Capacity Market", slide 8.

3 See *2021 Assessment of the ISO New England Electricity Markets*, Potomac Economics, Ltd., June 2022.

Section II of these comments analyzes ISO-NE's winter supply-demand balance and demonstrates the potential reliability impact of improved oil inventory management at existing plants. Section III illustrates how existing market-based mechanisms such as PFP help alleviate fuel security concerns but why additional measures are needed to fully address winter reliability planning needs. Section IV discusses the need for capacity market enhancements and proposes a basic framework for addressing winter fuel issues in the capacity market. Section V provides our conclusions and recommendations.

II. Better Utilization of Existing Plants can Address Most Winter Reliability Needs

Winter reliability is a concern because an increasing share of New England's generation is at risk of being unavailable on cold days due to lack of fuel. Winter peak load is much lower than summer peak load, so there is more capacity on the system than is needed in winter. However, an increasing share of New England's capacity has limited fuel supplies in winter. This includes gas-only generators that rely on interstate pipelines, oil-fired or dual-fuel units with limited fuel inventories, pumped-storage and battery storage resources, and solar generation. New England may not be able to rely on imports from New York unless they are backed by firm capacity transactions with fuel-secure generators because New York faces similar challenges. The amount of dispatchable winter capacity not dependent on gas or oil has declined by 2.7 GW since 2014, including the retirement of 1.3 GW of nuclear capacity. In the next several years, an additional 1.6 GW from the LNG-backed Mystic 8 and 9 units will retire. This section analyzes the current resource mix and its capability to satisfy the needs of the system during an extreme winter scenario, highlighting cost-effective measures that could be motivated through capacity market design reforms.

Figure 1 shows ISO-NE's supply mix for the 2025/26 winter (based on the winter capability of units with CSOs and historic imports) compared to a 90/10 net peak load forecast, which reflects load conditions most likely to affect reliability in a resource adequacy study. Total supply of 33 GW vastly exceeds the net peak load, but this margin shrinks substantially if New England's 9 GW of gas-only generators and up to 1.4 GW of imports from New York are not available. It is reasonable to expect that no natural gas will be available to pipeline-dependent generators in New England under 90/10 peak winter weather conditions.[4] [5] Of the remaining 23 GW of supply, a large share has significant duration limitations, including:

- 1.6 GW of oil/dual fuel generators with maximum inventories of 3 to 7 days
- 3.9 GW of oil/dual fuel generators with maximum inventories of less than 3 days
- 3.3 GW of storage and active demand response.

Hence, while ISO-NE has enough resources to meet winter peak load, it is unclear if it can maintain reliability during a sustained period of high load in which many of these limited resources are depleted over multiple days or weeks.

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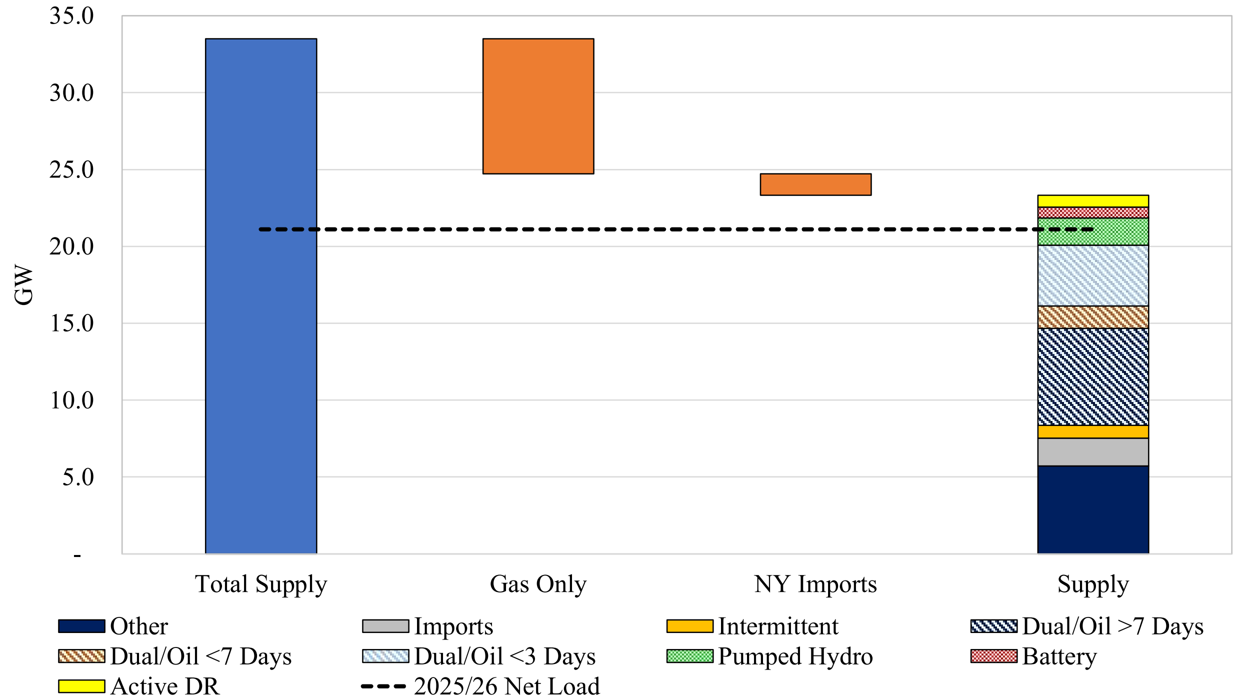
[4] Appendix chart A-5 shows that gas LDC planning requirements exceed the capacity of the gas pipeline system under design day criteria. This requires gas LDCs to satisfy a portion of their design day requirements with local LNG storage and/or LNG imports to the region. It is reasonable to expect gas LDCs to procure all of the available pipeline capacity for their firm customers under design day conditions.

[5] As winter peak load decreases from a 90/10 peak level, purchases of gas by LDCs will fall from 100 percent of pipeline capability to levels that allow electric generators to use some natural gas. Appendix chart A-6 illustrates the daily consumption of gas by LDCs and the amount of gas consumed by electric generators in New England and Eastern New York on each day during the winter of 2017/18, removing incremental gas consumption that is made possible by LNG imports to the region since LNG imports should not be assumed to be available on a non-firm basis in a resource adequacy assessment. Appendix chart A-7 shows the daily consumption of gas by electric generators (net of LNG imports) by daily peak load level, illustrating that the availability of gas to electric generators increases as load falls from the 90/10 peak winter level.

Figure 1: ISO-NE Winter Supply vs. Extreme Winter Peak Demand



Despite the region's reliance on oil-fired and dual-fuel resources, these plants do not routinely maximize their ability to sustain output during an unusually cold winter. Oil-fired and dual-fuel resources entered the 2021/22 winter season with only 52 percent of maximum oil tank capacity filled, and inventory levels did not significantly exceed this level at any point in the winter. The average fuel inventory at the beginning of the past four winters was 53 percent of maximum capacity, down from 73 percent in the preceding four winters (during which the Winter Reliability Program was in effect). Also, while most plants indicate on ISO-NE surveys that they can schedule fuel deliveries during winter to replenish fuel consumed, total inventories historically have not returned to their starting levels at any point in the winter following major periods of oil consumption.

We performed an analysis to demonstrate the reliability impact of oil-fired and dual-fuel resources' starting inventory and replenishment decisions in a severe winter. We developed a simplified hourly chronological model that compares available resources to load in December through March. Our analysis employed the following the assumptions:

- *Capacity*: We include resources with CSOs for the 2025/26 winter.
- *Load*: Total load consistent with the latest CELT forecast for the 2025/26 winter, with peak loads up to the top 10th percentile forecast. We used hourly load shapes based on the 2013/14, 2014/15, 2017/18 and 2021/22 winters to capture different timing and duration of high load events.
- *Generator Outages & Derates*: We modeled the largest fuel-secure generator – the 1,250 MW Seabrook nuclear plant – out of service for the entire winter to reflect a scenario with a major supply contingency. We applied a 5 percent derate to other dispatchable resources.
- *Gas Supply*: We estimated the amount of gas-fired generation available each day based on the historical relationship between pipeline gas generation and winter peak load.[6] This reflects only gas from interstate pipelines and assumes no imports of LNG.[7]
- *Oil Inventories*: We assumed that units with limited inventories run when needed until their inventories are depleted and units with smaller inventories are generally deployed after units with larger inventories. We examined three cases with different oil inventory assumptions:
  (1) 2021/22 Inventory Case: assumes oil-fired and dual-fuel resources enter the winter with the same inventories they had for the 2021/22 winter;
  (2) Max Inventory Case: assumes oil-fired and dual-fuel units enter the winter with inventories filled to maximum tank levels; and

6 We analyzed the historical relationship between ISO-NE gas generation (net of LNG imports) and daily winter peak load in our 2021 Assessment of the ISO New England Electricity Markets (available here, see section IV.B). We used this relationship to determine the amount of non-LNG gas generation that could run each day based on the daily peak load. The relationship is shown in Appendix Chart A-7 of these comments.

7 Historical data on pipeline flows and demand from gas utilities and power generators shows that in very cold winter weather, gas pipelines into New England are fully utilized and additional power generation is made possible only by imports of LNG to the region. See Appendix charts A-5 and A-6. Since the purpose of our analysis is to determine the amount of contracted LNG imports that are needed after accounting for other resources, we assume no imports of LNG in the baseline model.

(3) Max Inventory + 14-Day Replenishment Case: assumes oil-fired and dual-fuel units begin with maximum inventories and are assumed to replenish spent fuel within 14 days.[8] [9]

Each case assumes no LNG deliveries occur and no imports from NYISO. This is to evaluate the quantity of these resources needed to maintain reliability after accounting for ISO-NE oil and dual fuel units' capabilities. Hourly modeling results are provided in Appendix Charts A-1 to A-4.

Figure 2 shows the contribution of various resources on critical days (defined as days in which any amount of oil or LNG is burned in our model results).[10] This analysis shows:

- Out of 31.9 TWh of load on such days, 22.7 TWh is supplied by available pipeline gas and other resources including nuclear, renewables, and imports from areas other than New York.
- If oil-fired and dual-fuel units are limited to the inventories they had at the beginning of the 2021/22 winter, there is a major (7.4 TWh) shortfall of generation relative to demand over the season.
  - However, oil-fired and dual-fuel units provide an additional 6.7 TWh if they begin with maximum inventories and refuel 14 days after use.
  - This leaves only 0.7 TWh needed from NYISO imports and LNG-fueled generation (equivalent to about 5.3 million DTh of gas if supplied only by LNG).
- For comparison, seasonal LNG imports alone (excluding LNG supplied directly to Mystic 8 and 9) have ranged from 13.8 to 29.5 million DTh in the past five winters.

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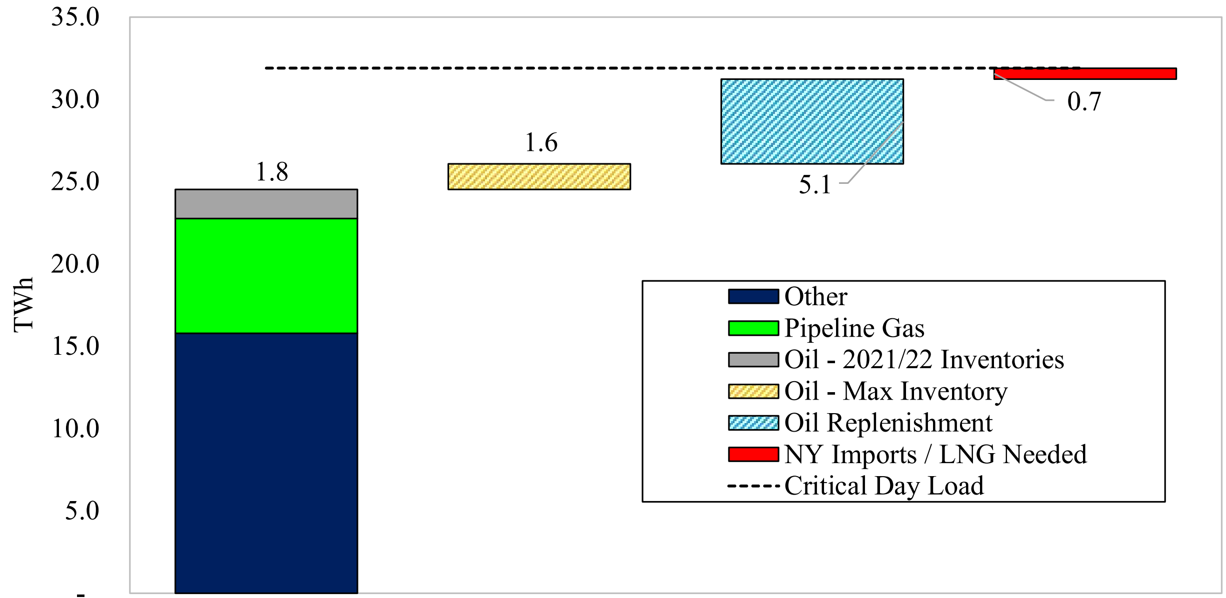
8 We use a 14-day period for replenishment to account for supply chain constraints or road blockages that may limit the ability of oil fired generators to be immediately refueled during or after a cold snap or blizzard. In practice, individual plants have unique transportation methods and arrangements with resupply vendors.

9 We did not explicitly account for the air permit limitations of dual-fuel generators, although generators with very small oil tanks tend to have restrictive air permits that limit utilization of oil. In our analysis, such units are generally not used until the most critical periods. The air permits of these units generally provide waivers for generators needed for reliability, but we did not specifically account for this.

10 Our analysis found an average of 84 critical days per extreme winter (assuming top 10th percentile load forecast and major generator season-wide outage).

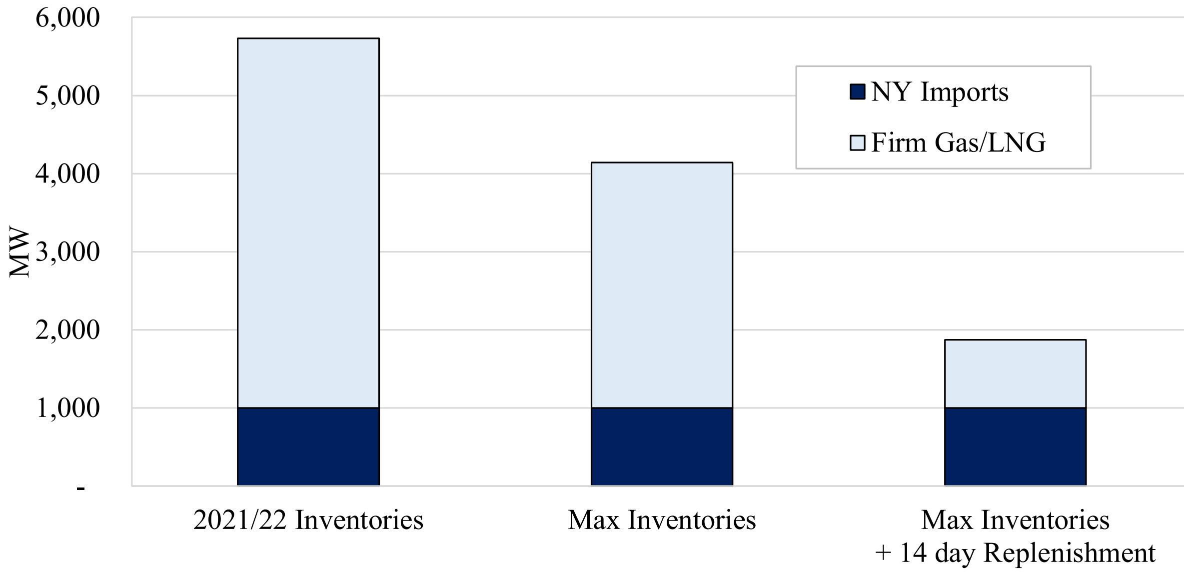
Figure 2: Energy from Oil-Fired and Other Fuel-Secure Resources on Critical Days
Average for 2013/14, 2014/15, 2017/18 and 2021/22 Load Shapes



It is important to note that the scenario we modeled reflects severe conditions with high winter loads, limited pipeline gas supply, and major derates of firm generation. This causes the number of critical days to be higher than expected. Hence, while the results show high levels of oil generation that may be undesirable for environmental reasons, oil generation in an average winter (or one without major lengthy derates of non-oil generation) will be much lower.

The analysis above assumes no initial LNG or NY Imports and quantifies the amount of energy that would need to be produced from oil. The next analysis shown in Figure 3 indicates the total capacity from New York imports and LNG-backed gas generation that would be needed to prevent load shedding under each of the oil inventory cases. We assume that approximately 1 GW of firm imports from NYISO are available given sufficient capacity prices in New England.

Figure 3: LNG and NYISO Imports Needed for Extreme Winter Conditions
Average for 2013/14, 2014/15, 2017/18 and 2021/22 Load Shapes



The results in Figure 3 show that if oil and dual fuel resources enter the season with the same inventories as in 2021/22 and do not replenish spent fuel, a large amount of capacity – approximately 5 GW – must be backed by LNG. However, if oil and dual fuel resources enter the winter with maximum inventories and replenish spent fuel within 14 days, the amount of LNG-backed capacity that is required drops to only 1 GW (equivalent to about 0.2 million DTh per day on critical days).

These model scenarios suggest that winter energy and peak demand in a stressed scenario can be met with modest levels of LNG imports even after Mystic 8 and 9 retire. However, the level of LNG needed is highly dependent on how oil-fired and dual-fuel plants manage their oil inventories. The optimal balance between these sources in a given year depends on global LNG prices, oil prices, the risks involved in contracting for gas in advance, and permit restrictions on oil units' operations, among other factors. Hence, the most efficient and reliable solution will not unduly favor one class of resources because this will undermine incentives for competing suppliers.

III. Existing Mechanisms Are Insufficient to Address Winter Reliability Needs

ISO-NE has several market products and programs that undoubtedly contribute to winter reliability. However, they are no longer adequate to ensure that the necessary amount of fuel-secure resources are maintained in-service and operated to satisfy the needs of the system under extreme winter conditions. This section gives an overview of existing mechanisms and their shortcomings in this regard.

Day Ahead and Real Time Markets – Energy prices in the day-ahead and real-time markets rise when oil is needed because the cost of burning it is included in generators' offers. This helps to maintain oil inventories (because oil will be priced out of the market when gas is widely available) and provides profits to generators that can burn oil more efficiently or obtain it at lower cost than the marginal supplier. If large amounts of oil-fired generation are routinely needed in winter, energy prices will encourage firms to maintain larger inventories to earn additional profits. As oil-fired units deplete their inventories, they reflect in their offer prices the opportunity costs of burning oil when supplies are limited, which raises energy prices and encourages suppliers to maintain higher oil inventories.[11] Hence, day-ahead and real-time market incentives motivate firms to prepare for expected winter conditions. However, the prospect of energy market profits in infrequent severe winters is not sufficient to encourage generators to consistently incur the cost of maximizing their inventories.

Forward Capacity Market – ISO-NE's capacity market is designed to procure capacity supply obligations (CSOs) from sufficient resources to satisfy summer reliability planning criteria. The Installed Capacity Requirement (ICR) is determined by simulating the amount of

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[11] The proposed day-ahead ancillary services market design will increase the ability of oil-fired units to earn profits from being scheduled for reserves in the day-ahead market. This will further increase the opportunity cost of oil-fired units with limited inventories, thereby increasing prices and the profitability of maintaining higher oil inventory levels.

capacity needed to maintain reliability under a wide range of conditions in a probabilistic resource adequacy model. In a well-functioning capacity market, prices rise when there is elevated reliability risk and payments correspond to resources' ability to address that risk. However, ISO-NE's capacity market is not designed to address winter reliability risks for the following reasons:

- Gas fired resources are assigned full capacity credit even if they lack firm fuel supplies. Hence, they lack incentives to contract in advance for LNG deliveries during winter.
- Oil and dual fuel resources are assigned full capacity credit regardless of their maximum inventory size, the actual level of inventory they maintain, or their commitments to replenish spent fuel.
- ISO-NE's resource adequacy model does not consider winter fuel limitations on gas and oil units, so it cannot detect and quantify winter supply needs in the ICR.
- ISO-NE capacity prices are the same in all months of a capability year, so investment in winter-capable resources will not be rewarded even if reliability risk is found to be concentrated in winter.

For these reasons, capacity payments in ISO-NE are effectively based on the value of reliability in summer exclusively. Hence, well-known winter reliability risks do not result in capacity payments that would motivate investment in and maintenance of winter-capable resources.

Pay-For-Performance (PFP) – Capacity suppliers in ISO-NE face large penalties for underperforming relative to their capacity obligations when reserve shortages occur. The hourly penalty rate – currently set at $3,500/MWh and increasing to $9,337/MWh by the 2025/26 winter – provides a strong incentive to be available in tight conditions. Non-capacity suppliers would be paid these rates to provide energy during shortages (along with capacity suppliers that exceed their capacity obligation). Hence, the PFP framework will likely motivate resource owners to maintain higher oil inventories than they otherwise would.

However, the incentive effects of PFP are limited for two reasons. First, operating reserve shortages (which are already infrequent in the summer) are far less likely in the winter than in the summer. In the summer, there are relatively few duration-limited capacity resources and reliability risk arises from a lack to total generating capacity, leading to reserve shortages whenever the amount of surplus capacity dips below the reserve requirement. This makes the likelihood of reserve shortages far greater than the likelihood of energy shortages. Accordingly, the most recent Net CONE study estimated that reserve shortages are over 11 times more likely than energy shortages.[12] However, if energy shortages occur in the winter, it will likely result from fuel limitations when there is an excess of reserve capacity. Our analysis in Section II found that reserve shortages were only 1 to 2 times as frequent as energy shortages.[13] Hence, winter reserve shortages are unlikely to occur until immediately before a load shedding event, making them very unlikely outside of a year with extreme winter conditions.

Second, despite the very high hourly penalty rate, stop-loss provisions cap resources' total exposure. A resource's monthly penalty limit is equal to its capacity supply obligation times the FCA starting price. The starting price for the latest FCA16 auction covering the 2025-2026 capability period was $12.4 per kW-month. Hence, in a month characterized by lengthy extreme cold spells, a resource's PFP penalties would be capped after just 1.3 hours of shortage at the $9,337/MWh rate. If a resource owner anticipates that a winter featuring a severe shortage event will occur with 10 percent probability, the expected value of its penalty cap is just $1.24

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12 See Concentric Energy Advisors, "ISO-NE Net CONE and ORTP Analysis", December 2020, Section 5.B. While the Net CONE study does not specify the expected loss of load hours (LOLH) at criteria, other ISO-NE analysis have generally found that an LOLE of 0.1 days per year results in LOLH of less than 1 hour per year. For example, see February 22, 2022, ISO-NE presentation "2021 Economic Study - Resource Adequacy Screen and Probabilistic Resource Availability Analysis Preliminary Results – Part 4."

13 Reserve shortages were 3 to 5 percent more frequent than energy shortages in scenarios in which oil inventories were limited to 2021/22 levels, and 33 percent to 139 percent more frequent in scenarios in which inventories were assumed to begin at maximum levels and replenish within 14 days.

per kW. Suppose the resource would need to keep 5 days of on-site inventory to avoid being deficient in at least 1.3 hours of the shortage event. According to recent assumptions developed by ISO-NE, the cost of maintaining this inventory would be approximately $9.30 per kW.[14] Moreover, while economic theory suggests that preventative costs should be incurred up to the expected value of a potential penalty, resource owners often place greater weight on more likely scenarios (such as a mild or moderate winter) when making business decisions. Hence, the PFP framework with the current stop-loss rules are not likely to motivate maintenance of inventories sufficient to deal with rare but severe conditions.

Inventoried Energy Program (IEP) – The IEP is a Commission-approved program that will be in effect for the 2023/24 and 2024/25 winters and is designed to encourage maintenance of fuel inventories. IEP employs a two-settlement system in which participants are paid a forward rate in exchange for committing to maintain on-site fuel or contracted LNG supplies on cold days. Performance is motivated by a 'spot rate' that penalizes or rewards participants based on their actual inventories on cold days compared to their forward commitments.

The IEP will motivate existing resources to maintain higher fuel inventory levels than they otherwise would. However, but it is not an adequate solution because it does not set prices and procurement quantities at levels designed to ensure that enough winter-capable resources will be available to satisfy winter reliability needs. The IEP pays an administratively-set rate that is targeted to ensure that most suppliers do not lose money by maintaining fuel inventories. For suppliers that can maintain inventoried energy at lower cost, the IEP rate will yield a small

14 ISO-NE presented an indicative value for the Winter Reliability Program (WRP) payment rate under recent market conditions of $61.10/bbl. on July 14, 2022. Assuming 42 gallons per barrel, 0.15 MMBtu per gallon of oil and a plant heat rate of 8 MMBtu per MWh, this equates to $77 per MWh of inventoried energy. Maintaining 5 days (120 hours) of energy would therefore have a cost of (120 x $77 = $9,295 per MW).

profit.[15] But the IEP's payment rate and the quantity of inventoried energy it procures have no relationship to the system's level of risk or the fixed operating and capital costs of suppliers. If annual ISO-NE capacity prices continue to be low because they only consider the surplus of summer capacity relative to summer peak load, it could lead resources that are more reliable in winter (such as oil and dual fuel units with large storage tanks) to retire because capacity prices do not cover their going-forward costs. For instance, 1.2 GW of currently existing oil and dual fuel units do not have CSOs for the 2025/26 winter. The IEP will do little to prevent these units from retiring because it is primarily designed to offset the cost of maintaining inventories and offers only modest additional profits to participants.

Winter Reliability Program (WRP) – The WRP compensated resources with on-site fuel for unused inventory at the end of the winter, with an administratively-set payment rate based on the assumed cost of purchasing and storing oil. It was last used in the 2017/18 winter. The WRP likely contributed to higher inventories in the years it was in effect. However, since it was designed only to cover the cost of maintaining inventoried energy, it is not a viable long-term solution for the same reasons as the IEP.

In conclusion, the existing market structures provide incremental incentives that will help motivate higher levels of resource availability during the winter, which will undoubtedly make New England more reliable. However, none of the existing market structures are designed to procure fuel-secure resources in sufficient quantities to satisfy a high reliability standard during

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[15] The approved IEP forward rate for the 2023/24 and 2024/25 winters is $82.49/MWh and covers 72 hours of inventory. Hence, a participant that never incurs a spot inventory deficiency will earn $5.9 per kW-year of IEP revenues. Profits will be lower than this for participants that must incur the cost of acquiring and maintaining more inventory than they otherwise would. Analysis by ISO-NE's consultant Analysis Group finds that an updated IEP forward rate reflecting recent market conditions would increase to $150/MWh. At this rate, the maximum payment (not including costs) would be $10.8 per kW-year. If costs incurred by oil and dual fuel units are similar to the recent indicative WRP base rate estimated by ISO-NE (based on the cost of maintaining oil inventories) of $61.10/bbl., then profit from participating in the IEP would be approximately $5.3 per kW-year ($0.44 per kW-month on an annual basis).

colder than normal winter conditions. Hence, the next section discusses market reforms we recommend to cost-effectively achieve this level of winter reliability in New England.

IV. Capacity Market Enhancements Can Address Winter Reliability Planning Requirements

The analysis in Section II shows that the existing generation fleet is capable of maintaining reliability in the winter with high utilization of oil inventories and modest LNG imports. However, as we have seen, resource owners do not routinely maximize or refill their oil inventories and few gas plants contract for LNG deliveries.[16] The key problem is that ISO-NE's capacity market – which in theory should provide the 'missing money' for the resources needed to maintain reliability during rare but high-impact conditions – does not provide resource owners with incentives to incur the costs of these actions.

The capacity market is the appropriate mechanism for addressing winter reliability planning needs that result from limited fuel supplies. When resources earn payments based on: (1) the level of load shedding risk in a given time period and (2) the resource's contribution to reducing the risk, they have efficient incentives to invest in cost-effective measures to maintain reliability. Although 'energy adequacy' is sometimes contrasted with 'resource adequacy', there is no reason that fuel limitations of oil and gas resources cannot be incorporated into the probabilistic resource adequacy modeling framework. Resource adequacy models simulate all

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[16] LNG suppliers generally do not provide speculative 'spot' cargoes to New England, and most LNG deliveries must be contracted months before the winter. Gas-fired generators without contracts are frequently able to run on cold days due to deliveries of LNG into the system. This is because gas LDCs contract for enough LNG to satisfy firm demand in a hypothetical extremely cold "design day" scenario, but they rarely need all of this supply, so the excess often becomes available shortly before or during the operating day. Since gas LDCs ultimately have a claim on this gas supply, it is important not to mistake its availability under normal conditions with the amount of gas that would be available to generators in an extremely cold winter.

hours of the year chronologically and increasingly consider the details of hours other than the gross peak due to the rise of intermittent renewables and energy-limited storage resources.

ISO-NE is currently pursuing major reforms to its capacity market under its Resource Capacity Accreditation (RCA) project. This project proposes: (1) enhancements to ISO-NE's resource adequacy model to better simulate how various resource types affect reliability and (2) accreditation of resources in the capacity market based on their marginal contribution to reliability. ISO-NE has indicated that it plans to incorporate gas pipeline limits in its resource adequacy model as part of this project, with analysis scheduled for late 2022 and early 2023.[17] We support this proposal, which will make the capacity market's assessment of winter reliability risk more realistic and provide incentives for some gas-only resources to boost their accredited capacity value by procuring firm fuel (such as with contracts for LNG imports).

As a crucial next step, ISO-NE's proposed reforms should include modeling depletion of oil-fired and dual-fuel units' inventories in its resource adequacy model and accrediting resources accordingly. As our analysis in Section II demonstrates, assumptions regarding oil unit inventories and replenishment are critical. The capacity market is unlikely to attribute any value to winter reliability if its model assumes these units can run indefinitely. If fuel inventories are modeled and resources are accredited based on their inventory size and refueling commitments, oil-fired and dual-fuel resources will face strong incentives to maximize their winter supply readiness when the model detects risk related to winter energy adequacy.

The approach we propose fits squarely within the framework of the RCA project that ISO-NE is already pursuing. Moreover, modeling oil inventories will increase the value of that

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[17] See ISO-NE October 18, 2022, Markets Committee presentation, "Resource Capacity Accreditation in the Forward Capacity Market".

framework for analyzing *other* resource types, because each resource's reliability value is affected by its interaction with all other resources on the system. There are detailed issues underlying this general approach that merit additional analysis and consideration, such as:

- *Modeling of oil unit inventories and depletion* – oil and dual fuel units can be assumed to begin each winter with a fuel inventory that they certify in advance to ISO-NE and to deplete their inventory when they run in the model. Their position within the logic of the resource adequacy model (i.e., whether they are used before or after other energy-limited resources like pumped hydro) should be consistent with the incentives for energy-limited units.[18]
- *Modeling of oil inventory replenishment* – oil and dual fuel units that commit to refuel during winter can be modeled as replenishing their inventory at some length of time after running. The appropriate delay time before replenishment occurs requires analysis to avoid being overly optimistic or pessimistic. The assumed delay should be linked to the accreditation and obligations of capacity suppliers. Our analysis in Section II assumes a replenishment delay of 14 days, but some units might be capable of replenishing more frequently.
- *Creation of accreditation classes* – oil and dual fuel resources have a range of maximum inventory sizes and may make varying commitments regarding fuel replenishment.[19] To simplify market administration, it may be necessary to establish a set of discrete classes of oil and gas units (e.g., units obligated to replenish in 14 days vs 10 days).
- *Obligations of capacity resources* – a mechanism is needed to ensure that oil-fired and dual-fuel resources maintain and replenish inventories consistent with the requirements of their accreditation class. This can be accomplished by a requirement for regular provision of fuel inventory data to ISO-NE and penalties for failing to maintain

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18 For instance, units with smaller inventories generally have higher opportunity costs, so the dispatch logic should utilize resources with higher duration limits first. Pumped-storage units and battery storage units are unlikely to have incentives to charge during hours where oil is being utilized, so they are unlikely to have any opportunities to charge during the sort of multi-day cold snap that would threaten reliability during the winter.

19 In addition, many units have relatively restrictive air permits, which we did not consider in the modeling results presented in Section II. However, air permits tend to be most restrictive for units with the smallest tanks, which are dispatched less frequently in our modeling, and air permits are typically structured to allow oil utilization for conditions when gas is unavailable or the ISO indicates that oil use is needed for reliability.

inventories according to the accredited level. This approach would encourage oil and dual fuel units to efficiently manage their own inventory levels by including their cost of refueling in their energy market offers.

- *Timing of the capacity market* – ISO-NE operates its capacity market on an annual three-year forward basis. This timing is poorly aligned with when plant owners are likely to make fuel procurement decisions, since it would require them to commit to their fuel contract or inventory status excessively far in advance. In the long-term, we recommend that ISO-NE move to a prompt seasonal capacity market, which could occur at a more appropriate time for plant owners to make such commitments.[20] In the short-term, it would be helpful to simply delay the timing of the FCA to occur closer to the delivery period.

Some commenters may argue that instead of the market-based approach we have outlined here, ISO-NE could simply identify the resources it needs for reliability and procure them under a cost-of-service approach – such as through fixed fuel inventory payments to all generators, large-scale infrastructure projects or a 'strategic reserve' of LNG. However, a market-based approach is much more likely to identify the most efficient reliability-improving projects. There are many actions that individual resource owners could take, including:

- Filling oil inventories at the start of the winter,
- Making arrangements to replenish spent fuel more quickly,
- Adding additional fuel storage tanks to existing oil or dual fueled units,
- Adding dual fuel capability or LNG/CNG storage tanks to existing gas-only units,
- Procuring firm LNG supplies,
- Importing fuel-secure capacity to ISO-NE from a neighboring region, or
- Investing in new capacity (including other technologies such as wind, which are likely to have a much higher capacity accreditation when reliability risks are driven by winter fuel limitations rather than peak summer load conditions).

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[20] See Section IV of our 2021 Assessment of the ISO New England Electricity Markets, available here.

The costs of each of these actions are plant-specific, are not known by any one entity and may vary from year to year. Top-down procurement of a specific resource (such as an LNG reserve) runs a high risk of selecting a costly option and crowding out less-costly investments. For example, some ISO-NE generators have temporarily leased additional oil tank capacity to expand their winter inventories in recent years. Capacity market enhancements would encourage this type of behavior, while a procurement approach would discourage it by providing payments to other projects while keeping market prices low.

V. CONCLUSION

New England has the capability to satisfy its winter reliability planning needs using the existing generation and LNG infrastructure. The key problem is that current market rules do not give resource owners adequate incentives to maximize the utilization of their assets to maintain reliability in the winter. In addition, the lack of specific capacity obligations related to fuel procurement leaves the ISO reliability planners without the information needed to assess the reliability of the system ahead of and during each winter.

Capacity market enhancements are a natural extension of the path ISO-NE is already pursuing. Such enhancements include: a) improving the accreditation of resources to reflect their fuel or other energy limitations and, in the long run, b) transitioning to a seasonal market that can reflects to region's winter supply and demand conditions that is run promptly before each season. These changes would provide efficient incentives for plant owners to maximize their inventories, obtain firm fuel supplies, and mobilize other available resources. The key analytical improvement needed to accomplish this is to model fuel limitations and oil inventory limits within ISO-NE's resource adequacy model (as we describe in Section II). Hence, we recommend that ISO-NE and its stakeholders expand the RCA project to include modeling of oil inventory limitations in the resource adequacy model and making corresponding changes to the level of accreditation for oil-fired and dual-fuel units in the capacity market.

The path we have described should ideally proceed through ISO-NE's stakeholder process. More crude interventions such as an ISO-procured LNG reserve are likely to undermine the development of effective capacity market signals that reflect the value of winter reliability. Hence, we recommend that the Commission allow this to be addressed through the stakeholder process in the same manner as other resource adequacy issues currently being considered.

Respectfully submitted,

/s/ David B. Patton

David Patton
President
Potomac Economics, Ltd.

November 7, 2022

APPENDIX A: HOURLY WINTER RESOURCE MODEL RESULTS

The following charts show hourly results from our winter resource model. The model compares available capacity to a simulated load profile, while keeping track of depletion and replenishment of limited inventories.

Chart A-1: 2022 Actual Load, Imports, LNG and Inventories

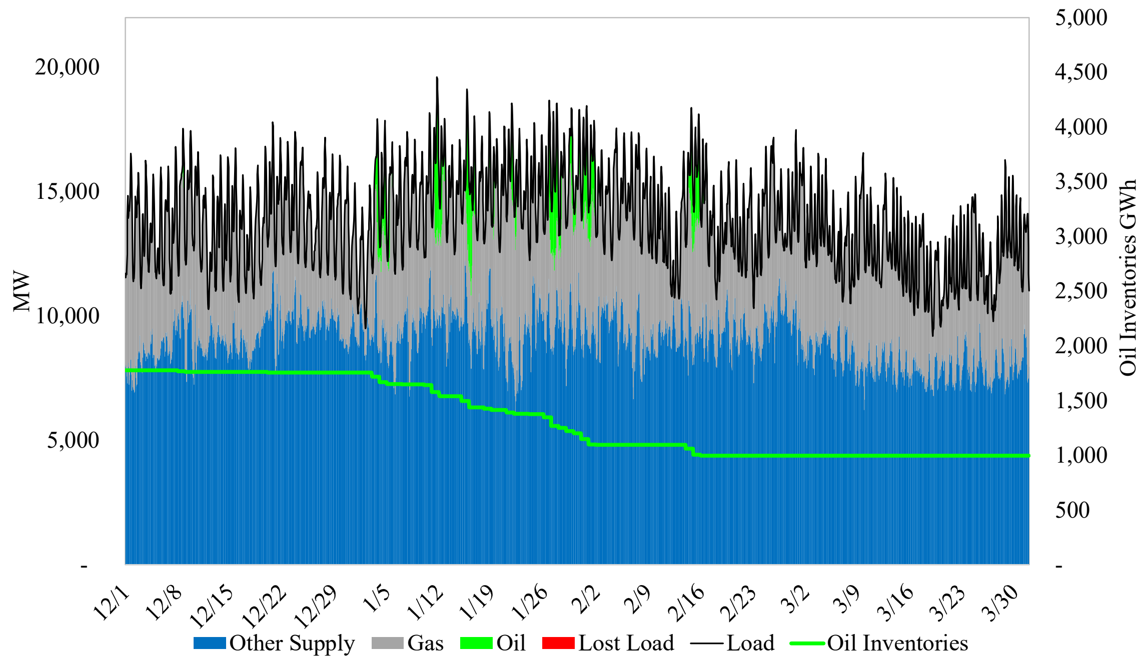


Chart A-2: Severe Winter, 2022 Inventories, No NY Imports/LNG

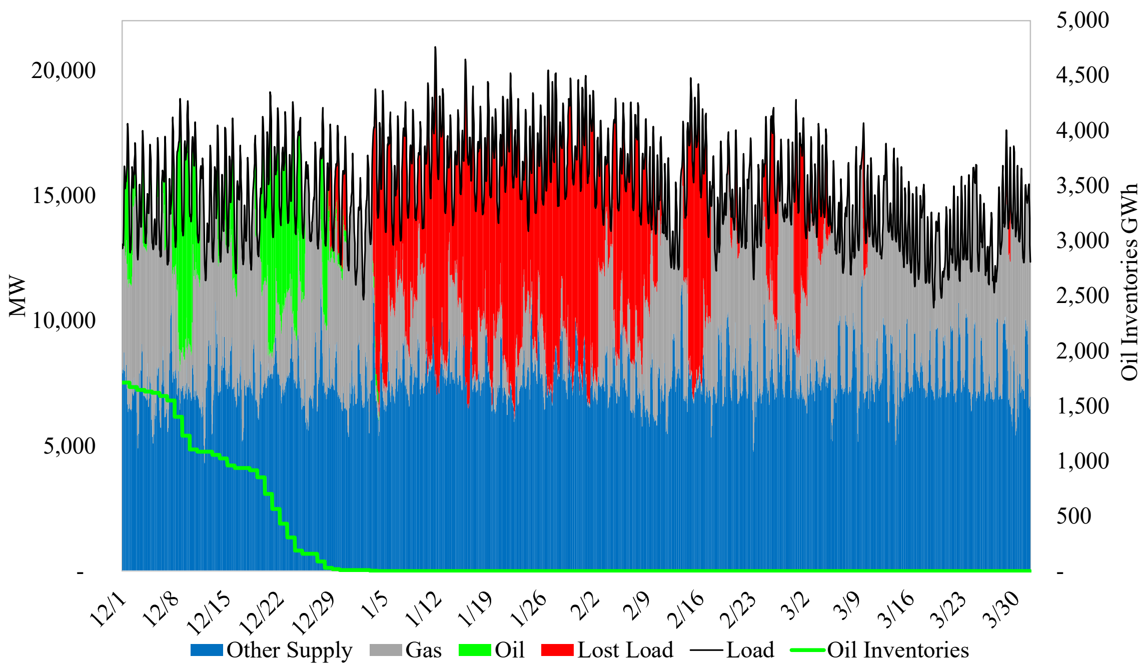


Chart A-3: Severe Winter, Max Inventories with 14-day Replenishment, No NY Imports/LNG

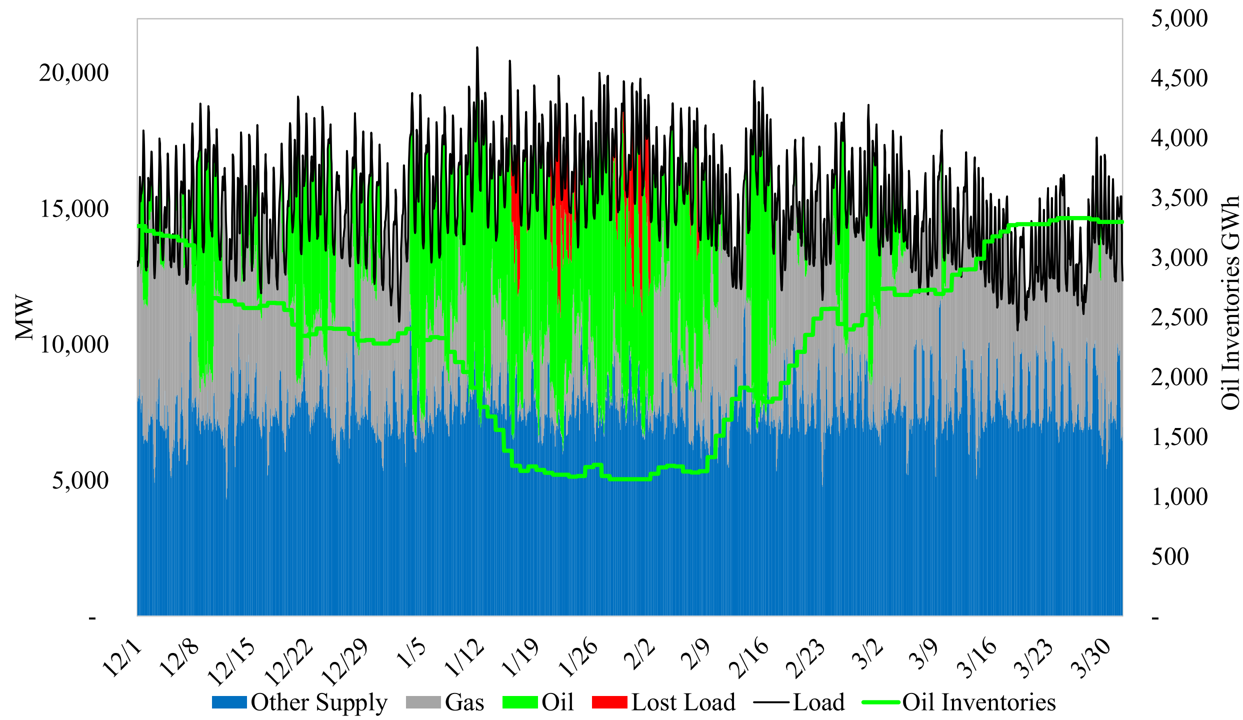
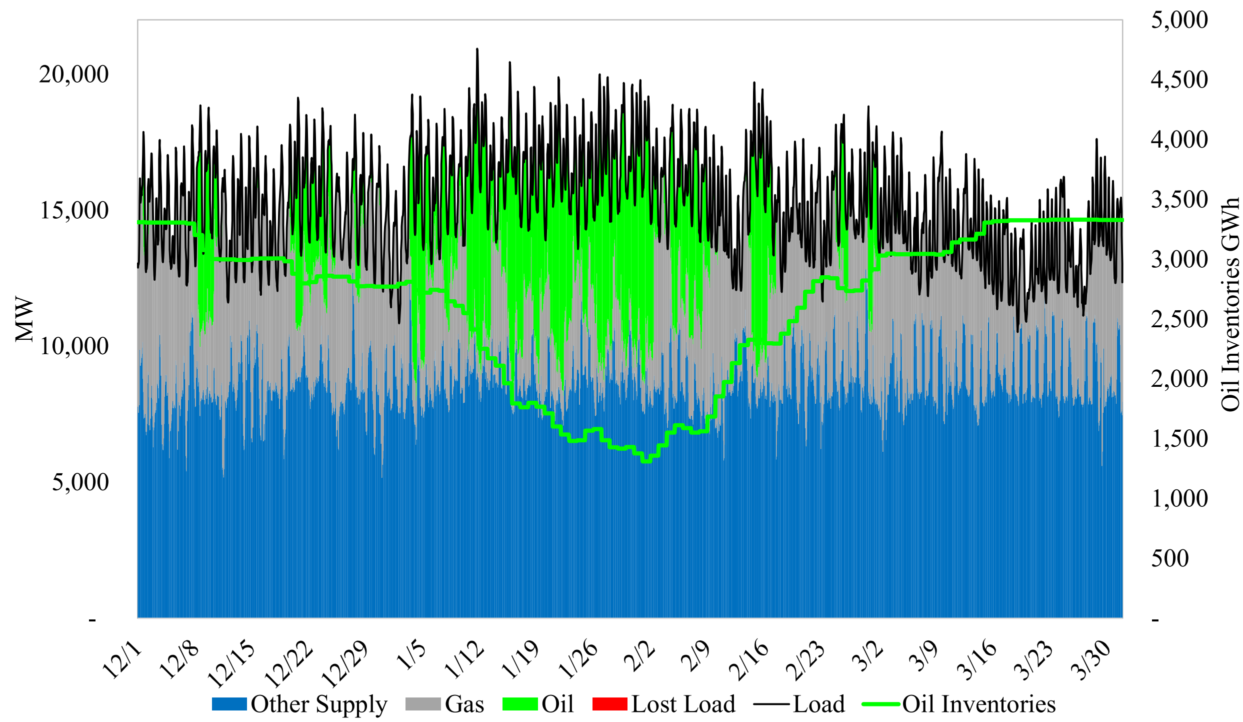


Chart A-4: Severe Winter, Max Inventories with 14-day Replenishment, 2 GW NY Imports/LNG



The following three figures summarize core heating demand in New England and eastern New York relative to available pipeline capability and the implications for gas supply available to power generators.

Figure A-5 compares the combined capacity of pipelines serving eastern New York and New England to the peak winter demand of LDCs. The LDCs' Design Day demand (i.e., demand of firm gas customers under extreme cold conditions for which LDCs plan their systems) exceeds 10 million Dth/day, while interstate pipelines are capable of providing approximately 8.3 million Dth/day. Design Day demand reflects conditions much colder than those typically experienced. The figure shows that estimated peak demand of LDCs under weather conditions similar to late 2017/early 2018 cold snap would be approximately 8.8 million Dth/day, which still exceeds the capability of interstate pipelines.

Figure A-6 compares pipeline gas and LNG imports to on-peak power generation in eastern New York and New England during the 2017-2018 winter. We estimate LDC demand as the difference between total gas supply and power plant consumption. During the cold snap of late December and early January, pipeline gas imports reached their limits and LNG imports to the region increased. The relatively small amount of gas-fired power generation that continued to run during this period likely would not have been possible without LNG imports adding to the regional gas supply.

Figure A-7 compares daily ISO-NE winter peak load to on-peak power generation fueled by pipeline gas. We estimate pipeline gas generation by netting out LNG imports from total power plant gas consumption and adjusting on-peak generation levels proportionally. Pipeline gas generation falls as winter load rises, reaching very low levels at the 50/50 or 90/10 CELT load forecast levels.

Chart A-5: Summary of LDC Gas Supply and Demand

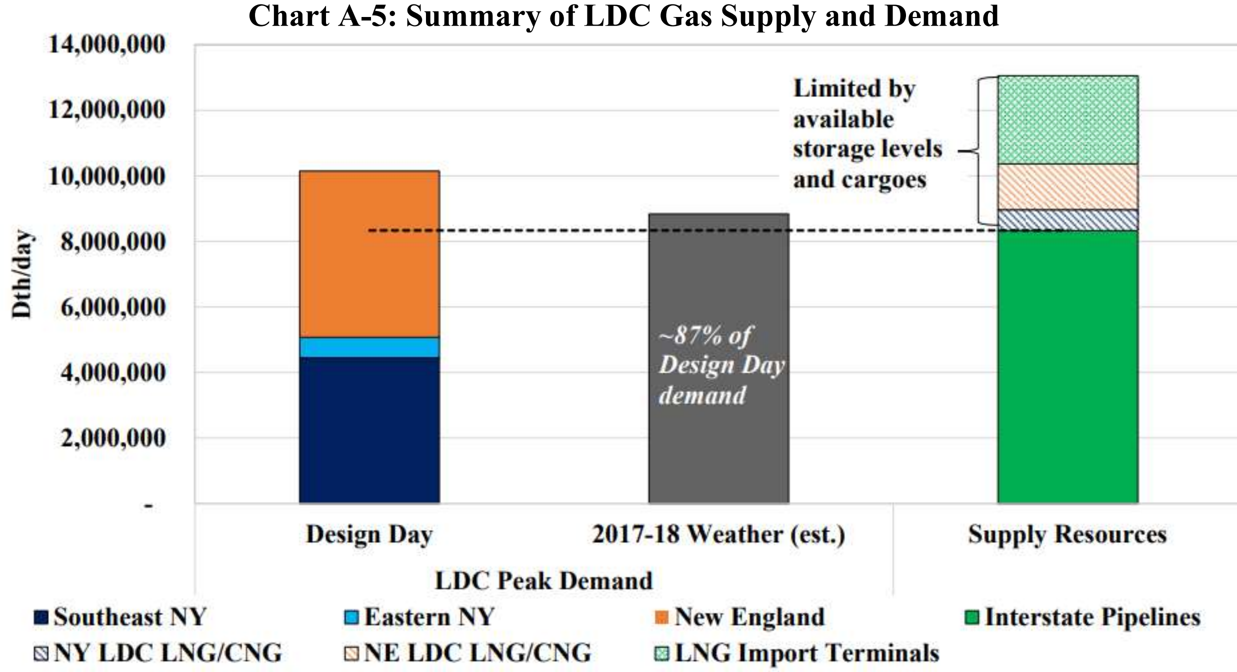


Chart A-6: Regional Pipeline Gas and LNG Consumption, Winter 2017-18

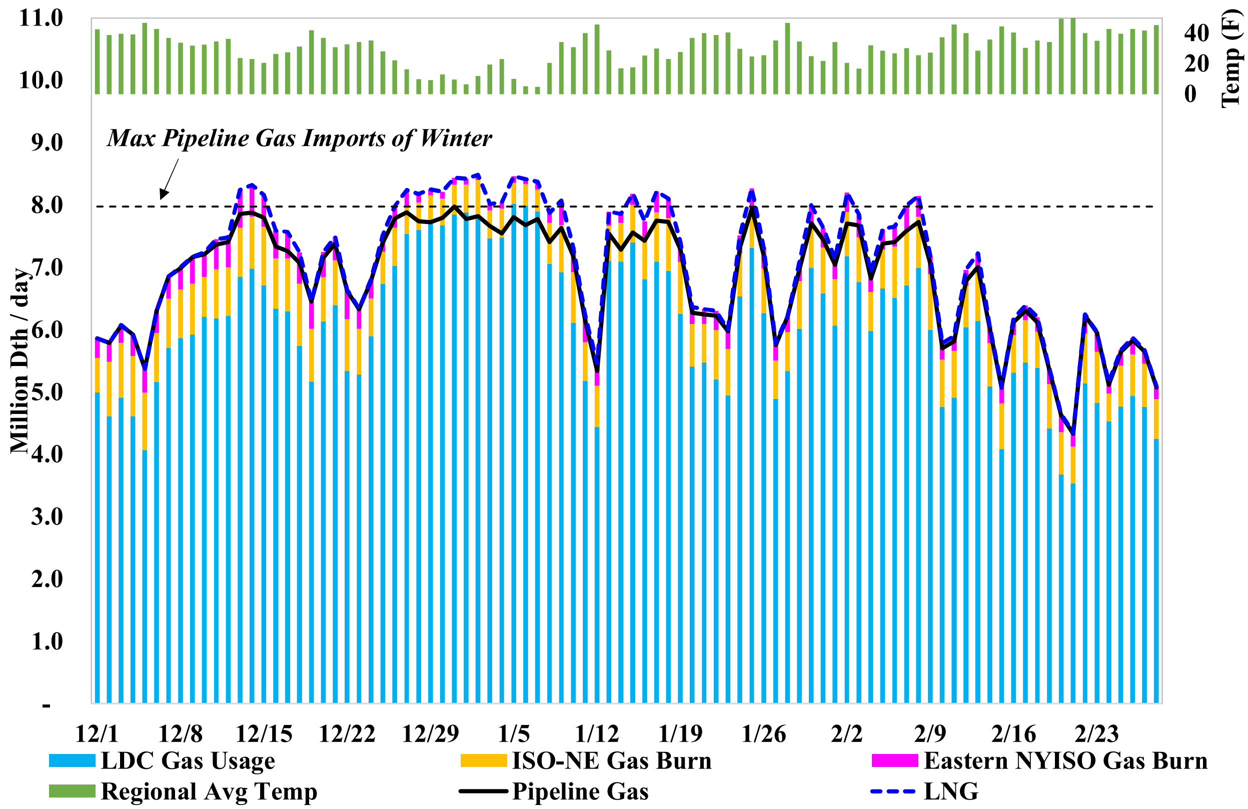
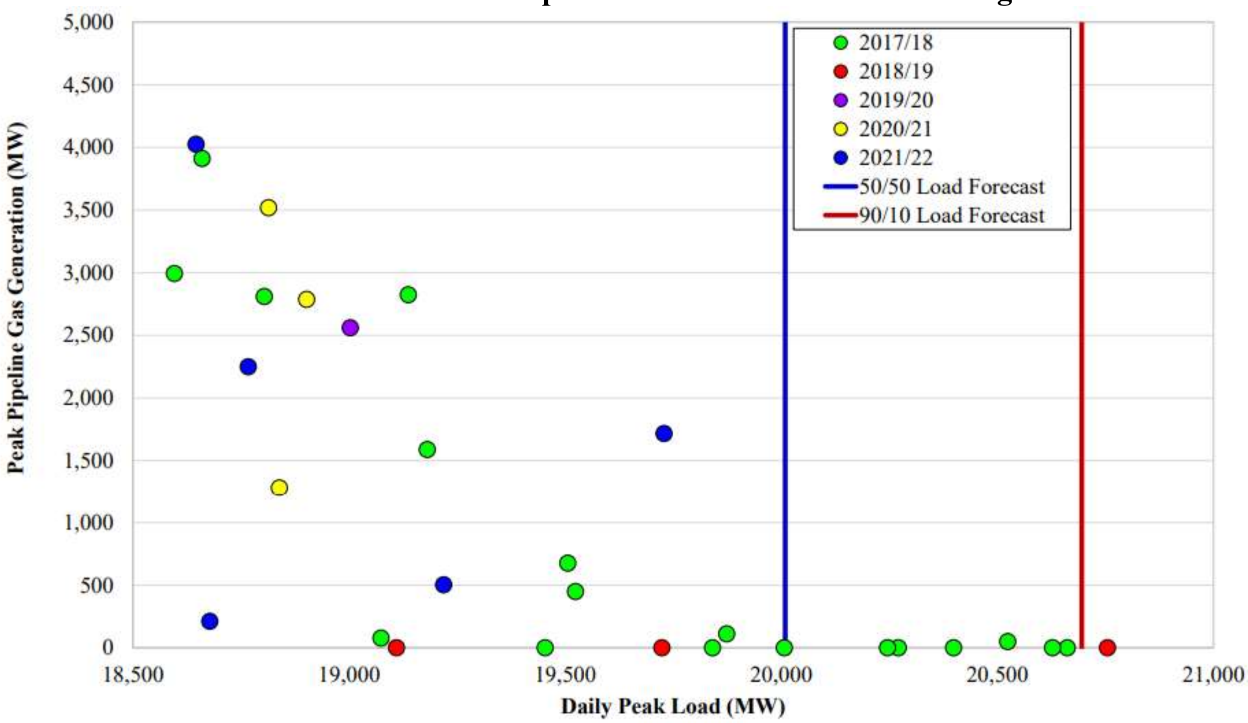


Chart A-7: Winter Peak Pipeline Gas Generation in New England



CERTIFICATE OF SERVICE

I hereby certify that I have this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 7th day of November 2022 in Fairfax, VA.

/s/ David B. Patton

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