Gordon van Welie
President and Chief Executive Officer

January 19, 2024

The Honorable Jeff Duncan
Chairman
Subcommittee on Energy, Climate, and Grid Security
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Duncan:

Thank you again for the opportunity to appear before the Energy Subcommittee on September 28, 2023, and I appreciate the opportunity to respond to the questions below.

Please let me know if you have further questions or need additional information.

Sincerely,

Gordon van Welie
President and Chief Executive Officer

cc:
The Honorable Diana DeGette, Ranking Member, Subcommittee on Energy, Climate, and Grid Security
The Honorable Kelly Armstrong
The Honorable Ann L. McLane Kuster

The Honorable Jeff Duncan

1. *A historic benefit of wholesale markets is that they created competition and shifted financial risk from ratepayers to private investors.*
    a. *Do you believe that state policies mandating the use of, or providing subsidies for, certain types of generation shift the financial risk back to ratepayers?*

Response:

Competitive wholesale markets have shifted financial risks, allowing for bad financial decisions to be borne by shareholders instead of ratepayers. In New England, the states have adopted policies in support of certain types of generation resources, which they believe are an essential part of changing the resource mix in the region. In most instances, these policy decisions have been implemented in a way that affects the ratepayers in each individual state. As explained further in the response to question two, how these resources are subsidized is more an issue than the actual subsidies themselves.

2. *Is there evidence that subsidies for grid scale battery storage, solar, and wind resources suppress capacity and energy market prices in your region? If so, please describe.*
    a. *In your opinion, have subsidies negatively affected market outcomes? Do subsidies for batteries, solar, and wind discourage investment for new dispatchable thermal generation? How much have these market conditions contributed to the retirement of existing dispatchable thermal resources?*
    b. *Do these subsidies and their effects on markets make your system more reliable or less reliable?*
    c. *What steps are you taking to ensure that these subsidies are not unduly discriminatory and preferential, and that rates remain just and reasonable?*
    d. *Would you consider state renewable mandates as out of market interventions? Would you consider the mandates as a form of market power?*

Response:

All resource/fuel types have received some form of subsidy at some point in their evolution, so it is understandable that New England policymakers who wish to reduce carbon emissions and accelerate the development of emission free renewable resources would want to provide economic incentives to spur the development of new carbon-free resources.

The problem is not the subsidization itself, but rather the manner in which these incentives are presented – since they are typically presented outside of the wholesale electricity market. This means that there is an externality, i.e. the cost of carbon emissions, which is not being directly valued in the wholesale electricity market. This leads to price distortions in the wholesale market, with a trend toward lower energy prices and a resultant high dependency on capacity market revenues. This is quantified in the ISO's Pathways Study, which was prepared by ISO-NE and Analysis Group to examine different pathways to a future electric grid.

The price suppression in the energy market, coupled with the difficulties of ensuring efficient price formation in the capacity market, can lead to premature retirements of the resources that will be needed to balance the system. This may result in reliability problems, which could be exacerbated by other constraints on the usage of fossil fired resources, and/or if electrification load grows more quickly than the net change in supply (new entry minus retirements). These potential risks are documented in a recent ISO-NE study on Operational Impacts of Extreme Weather Events (see Probabilistic Energy Adequacy Tool (PEAT) analyses).

A market-based solution to the price distortions caused by out-of-market incentives is Net Carbon Pricing (NCP). This would materially improve the balance in revenues between the energy and capacity markets, improve reliability at modest cost to consumers, and provide incentives to existing fossil resources (especially gas fired resources) to reduce their emissions. It will also support existing nuclear resources, which are important resources in the region (see PEAT analysis).

While the ISO is supportive of an NCP mechanism in the New England wholesale market, state or federal legislative action may be needed to set a price for carbon and to require generating plants to pay it.

3. *Are changes to how the capacity market procures resources needed to ensure that sufficient dispatchable thermal resources are, and remain, available to the system? How far in advance of that timeframe do you need to make changes to avoid resource adequacy and reliability issues?*
    a. *Multiple regions are considering modifying the annual timeframe of capacity auctions. Would sub-annual capacity auctions result in more robust outcomes if the way in which the auctions operate, outside of procuring for a season versus a year, is the same as the current annual capacity market?*
    b. *Should changes to capacity accreditation go into effect before other changes to the capacity market?*
    c. *Are forward looking markets like capacity markets needed to procure enough resources that can provide essential reliability services?*
    d. *Are you concerned that there will be a recurring need to defer retirements or enter into out of market contracts to retain generators if subsidies persist and the markets do not change to correct inefficiencies?*
    e. *Do all resources with a capacity obligation have a must-offer requirement in the day-ahead market? If not, why not? What effect does not having a must-offer requirement have on the day-ahead and real-time markets?*

Response:

Capacity markets – the Forward Capacity Market (FCM) in the case of New England – are critical for ensuring that the New England power system will have sufficient resources to meet the future electricity demand. Generally, the ISO runs the auction for the FCM each year to procure the necessary resources to meet consumer demand for electricity three years later.

The ISO is currently in the process of making changes to the FCM to ensure sufficient resources are available when the system is at peak demand or under stress. Specifically, we are looking to alter the existing market structure through modifications to the Resource Capacity Accreditation (RCA) process. These changes will help ensure that all resources are appropriately accredited into the FCM. As part of this process, the ISO filed revisions on November 7, 2023, with the Federal Energy Regulatory Commission (FERC) to the ISO's Transmission, Markets and Services Tariff to delay the nineteenth Forward Capacity Auction (FCA) for one calendar year. The Commission granted the request to delay FCA 19 on January 2, 2024.

Delaying the auction for FCA 19 for one year will afford the region the necessary time to complete the ongoing work on a new methodology in the FCM for calculating RCA values so that this methodology can be implemented in FCA 19. This delay will also allow the ISO and the region time to evaluate other, more fundamental, changes to New England's capacity market design, namely a possible transition to a prompt market structure with multiple seasonal auctions.

The timeframe for these various changes to be implemented will vary. With FERC approval, the ISO will now conduct a stakeholder process to gather recommendations and feedback on changes to the RCA process with the goal of filing those proposed changes at the end of 2024. If approved, we expect these changes to go into effect during FCA 19, which is currently scheduled for February 2025 (this auction will procure resources for the 6/01/2028 – 5/31/2029 capacity commitment period). However, should the ISO and the region decide to move forward with a prompt and seasonal design for its capacity market, the ISO will be making additional filings with FERC to transition to the new market in the 2027/28 timeframe. This new market, if approved, would replace FCA 19.

ISO-NE currently evaluates the impacts of generator retirements through its FCM. That process gives our region a three-year look ahead at potential retirements. It is important to note that the ISO has limited tools for retaining existing resources that are set to retire – as established by our FERC-approved Tariff. The most recent example of the ISO exercising those tools was the decision in 2018 to retain the Mystic Generating Station (Boston, MA) for two years, from 2022 to 2024. After studying and identifying the resulting adverse consequences for New England's energy security, ISO-NE moved to retain the Mystic units for an additional two years (under a FERC-approved agreement), giving the region time to implement reliability solutions, including allowing time for the development of new resources, before the units' eventual retirement in mid-2024. The potential for retaining future retiring resources will be dependent on how quickly new resources are able to come online and supply our region with additional capacity.

All resources with a capacity obligation have a must-offer requirement in the day-ahead market.

4. *Please describe your generator retirement process. Are current retirement processes that retain resources while transmission upgrades are implemented sufficient to prevent the scale of retirements facing RTOs/ISOs?*
    a. *Do you consider issues other than reliability violations on the transmission system when assessing the impacts of proposed generator retirements?*
        i. *For example, should violations of other reliability criteria, shortfalls of FERC-approved resource adequacy requirements, or need for essential reliability services be considered when a generator proposes to retire?*
    b. *Should RTOs/ISOs be able to retain generators until the capacity, energy, and essential reliability services they provide are replaced?*

Response:

In New England, the generator retirement process is aligned with the Forward Capacity Market (FCM) period. Through that process, a generating resource has the option to de-list temporarily from the auction or retire from the market altogether. These applications are coordinated through the FCM processes.

As mentioned above, New England has exercised the ability to retain resources for reliability purposes while transmission upgrades are implemented. This has happened previously in both the Greater Boston Area and in Southeast New England. When this occurs, the ISO evaluates generator retirements using the criteria established through our FERC-approved Tariff. In general, the ISO has limited ability to retain resources for reasons other than the need for transmission upgrades. The ISO did retain the Mystic gas-fired generating facilities in Boston for a limited, two-year timeframe for fuel security reasons, but that authority no longer exists in our Tariff. In addition, in the five-year period since the decision was made to retain the Mystic units, the transmission system has been reinforced to allow for the retirement of the units, and sufficient additional resources have been added to reduce the energy adequacy risks to a manageable level in the near term (2027).

Looking forward, one of the challenges for the clean energy transition is managing the reliability of the system, as resources retire and new resources come online, and evaluating potential gaps that may materialize. The ISO has developed a sophisticated analytical tool to forecast the risk of future energy shortfalls and will utilize this tool to maintain situational awareness and keep the region informed on the trajectory of regional energy adequacy risks.

5. *During your testimony, you stated that electrification and "transition" on your system will result in a doubling of average demand and tripling of winter peak demand by 2050. You then stated that this requires a need for significant additions of intermittent renewable resources to meet state policy goals and for sufficient flexible resources, like natural gas-fired power plants, to balance the system during periods when these intermittent renewables are unable to produce electricity. The nation's top reliability organization, the North American Electric Reliability Corporation (NERC), and leaders from the Federal Energy Regulatory Commission (FERC), have testified that the bulk power system is confronting a potential reliability crisis caused by the potential loss of dispatchable thermal generation. This issue grows greater with the proposed EPA rules that will discourage coal and natural gas-fired generation. When do you anticipate reliability concerns materializing, or have they already materialized? What are you doing to solve this resource adequacy crisis and potential reliability crisis?*
    a. *How do you plan to retain the existing dispatchable generation and incent the entry of new dispatchable generation if your markets currently do not?*
    b. *If your system is already facing resource adequacy issues without electrification and demand increase, how will the system be able to sustain large growth amidst significant thermal resource retirements?*
    c. *It appears that capacity obligations and performance requirements fail to reduce the impacts of winter storms. Does your market structure provide incentives for winterization of natural gas infrastructure or firm fuel supplies? What steps is ISO-NE taking to incentivize weatherization of natural gas infrastructure or firm fuel supplies?*

Response:

As the independent administrator of the wholesale electricity markets, the ISO has limited ability to retain particular generating resources for reliability. If a generator seeks to retire, we evaluate the impact of the retirement on the transmission system, but we cannot force a generator to remain in service. In the past two decades, New England witnessed a significant buildout of the generation fleet, with most of the new generation coming from dispatchable, gas-fired generators. The region's capacity market was an essential part of the financing of that investment.

As mentioned above, we believe the energy adequacy risks in the near term are manageable and we have developed tools to evaluate the risks as the system evolves over time. The risks will be dynamic over time, and will vary based on the relative rate of change of three variables: demand growth, new supply and retirements. The ISO is closely monitoring all three of these variables, and where necessary, making improvements to the market design and operational or planning practices.

The reliability risk of generator retirements would depend on many factors, including the pace of new resource developments, which could be in the form of new generation internal to New England or new or incremental transmission import capability from neighboring power systems. The reliability risk also would also depend on the pace of the growth in electricity demand to serve electrification of buildings and vehicles, as well as demand-side tools for retail electricity consumers, both of which are driven by state policies.

ISO New England recently developed the Probabilistic Energy Adequacy Tool (PEAT) to help state policymakers, regulators and other stakeholders in New England evaluate potential reliability risks, and we are moving forward with our stakeholders to consider the development of a potential Regional Energy Shortfall Threshold (REST) metric. Conceptually, projected energy shortfalls beyond this metric would be the prompt for the region to take additional mitigating actions, including for example, the procurement of additional reserves through the market. The ISO has worked closely with NERC to encourage all regions to assess these reliability risks in a consistent fashion.

New England has capacity obligations and performance requirements in the wholesale markets to strengthen the performance of resources when the power system is operating under stressed conditions. In addition, we are working on a project to strengthen the Resource Capacity Accreditation (RCA) process in the wholesale markets. The pay-for-performance mechanism in the capacity market has been successful in attracting resources when the system is in shortage conditions, and transferring payments from under-performing resources to over-performing resources while, at the same time, holding consumers harmless from the cost of those additional payments.

The weatherization you mention is common for generators built in this region. Developers generally build generators to be able to operate through typical cold weather in New England.

The ISO has instituted winter reliability programs in the past, and we are currently operating a FERC-approved Inventoried Energy Program for two years to bolster fuel supplies in the winter.

6. *While the interconnection queue is large, not all resources in the queue get built. What percentage of the generation queue has historically come onto the system? How much from the existing queue do you expect to be built?*
    a. *Can you provide an estimate of the gross cost of all the additional renewable capacity you expect to get built?*
    b. *Can you elaborate on the projects that are delayed or canceled due to cost increases?*
        i. *What is the reliability impact of these delays and cancelations if they force retirement of existing dispatchable thermal resources but no new capacity is added?*
        ii. *Are these projects subject to financial penalty if they are unable to meet their obligations? Should project financers and sponsors be required to pay for any out of market actions to retain dispatchable thermal resources?*
    c. *Can you describe how much additional dispatchable thermal generation you will need to balance the system if renewables are added to meet state goals? Is it financially sensible to add significant amounts of generation to meet state goals only to need to add more generation to maintain balance on the system?*
    d. *Can additional natural gas-fired generation capacity be served by the current pipeline infrastructure or is additional pipeline infrastructure needed?*
    e. *Have you been consulted by EPA or FERC on the proposed power sector regulations?*
    f. *If the EPA rules are enacted, will you be able to reliably operate your system?*

g. *Should nuclear play a larger role in reliably operating the system and meeting state emission targets?*

Response:

Developers do not build all of the generation projects they propose to the ISO for interconnection studies. In fact, almost 70% of proposed new megawatts in the Queue have historically been withdrawn. The ISO's current Interconnection Queue consists of more than 40,000 MW of wind, solar, storage, natural gas, and hydroelectric resources. In total, as of November 1, 2023, 204 generation projects were being tracked in the ISO-NE Interconnection Queue. If historical trends continue, we expect around 30% of these projects to interconnect to the system.

Within the ISO Generator Interconnection Study Queue, we track the amount of capacity proposed and the locations on the transmission system; however, we do not consider the cost of developing the resource itself. Our evaluation of cost is focused on the transmission upgrades needed to interconnect the resource.

Projects in the Interconnection Queue can be delayed or withdrawn for various reasons. In our experience, developers will often evaluate multiple interconnection points without necessarily planning to build everything under study. Developers have also faced a number of challenges over the years, including issues with costs, the supply chain, as well as siting or permitting of resources.

If a resource were to take on a capacity obligation through the capacity market that they are unable to meet due to siting, interconnection or other factors, the resource would be subject to financial penalties. It's important to note, however, that the ISO is adjusting the interconnection process to comply with FERC Order 2023, which will facilitate the processing of projects.

In the near-term, we anticipate that the existing resources connected to the grid will be able to balance renewables as they are added to the grid. The gas-fired fleet will provide the bulk of those balancing services, supplemented by other resources such as grid-connected storage (pumped hydro and lithium ion), demand response resources, oil-fired peaking generators, etc. We do not anticipate adding thermal generation to the system. In New England, we are likely to transition to a system where renewable energy provides a bulk of the energy to the system and gas-fired resources will be used more for ramping or peaking capabilities. Other technologies could displace gas-fired resources to provide that balancing capability in the long-term, but our studies show that we will remain dependent on gas-fired resources for the foreseeable future. The significant amount of renewable generation (wind and solar) that is proposed to be added to the system is largely being driven by state procurements to meet state policy objectives.

The existing natural gas infrastructure is constrained during cold weather periods. The interstate pipelines in New England were built to serve the needs of firm customers (primarily local distribution customers of gas utilities), and not the coincident needs of electric generation in the winter. During cold weather, when the natural gas system is constrained, the region's generating fleet shifts to burning oil or using imported liquefied natural gas as an alternative to pipeline gas.

EPA consulted with ISO New England and the other ISOs when the agency developed the Clean Air Act regulation on greenhouse gas emissions from fossil fuel power plants, and ISO New England ultimately submitted written comments to EPA in August 2023.[1]

Nuclear has played a significant role in reliably operating the system in New England for decades. Over time, we have seen the retirement of multiple nuclear stations. We anticipate that the existing nuclear fleet could operate well into the future, subject to market conditions and other factors. The owner of the Millstone nuclear power plant has a 10-year contract with the State of Connecticut to operate through 2028; however, the long-term future of that plant is uncertain.

We have not seen any proposals for new nuclear resources coming onto the system in New England. Some policymakers have expressed an interest in advanced small-modular nuclear reactors, although there are no specific policies or financial incentives for those technologies.

7. *Can you state the projected cost of the New England Clean Energy Connect transmission line?*
    a. *What is the expected cumulative cost of the transmission needed to integrate renewables?*
    b. *Can you describe your coordination efforts with neighboring RTOs/ISOs?*
    c. *What is your position on a minimum transfer requirement between planning regions?*
    d. *Would a minimum transfer capability requirement undermine the autonomy of the various RTOs/ISOs and their planning processes?*

Response:

The ISO does not review the costs of the New England Clean Connect transmission line or other Elective Transmission Upgrade (ETU) projects. Our responsibility with such projects is to review the reliability of the proposed interconnection.

The ISO is involved in several studies and collaborative efforts in New England and with neighboring systems. The ISO has developed a 2050 Transmission Study in consultation with the New England States and other stakeholders. This study examined the transmission infrastructure that would be needed to meet peak demand scenarios that are influenced by the states' electrification initiatives. In that study, we identified a range of potential transmission costs in the 2035, 2040, and 2050 timeframes. As part of the Eastern Interconnection, the ISO coordinates with New Brunswick, Quebec, and New York on interregional planning. The ISO participates in the Northeast Coordinated System Plan, and New England has a long history of operating cross-border transmission facilities to import and export power. Additionally, ISO New England has been working with the New England states, New York ISO, and PJM on an Interregional Transmission Planning Collaborative.

[1] Comments of ISO New England to EPA on New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units, August 7, 2023; https://www.iso-ne.com/static-assets/documents/2023/08/comments_on_epa_proposed_ghg_rule.pdf

We continue working with our neighboring systems, the ISO/RTO Council, FERC, and NERC, as further analysis is underway to examine the current transfer capabilities requirements between systems. Any minimum transfer capability requirement should consider each region's policies and preferences, as well as the ISO/RTO planning processes that support transmission expansion.

8. *ISO-NE is already energy constrained and requires additional programs like the Inventoried Energy Program and shipments of liquified natural gas (LNG) to the Everett Marine Terminal (EMT) and other LNG import facilities to meet winter demand. In your witness testimony, you argued that you believe that gas infrastructure and supplies will be needed well into the future until commercially available renewable fuels, or alternative technologies, are economic. In addition, the 2027 results for the joint study with Electric Power Research Institute show "manageable risk" but still show potential for energy shortfall. You also state that variables and risks for 2032 are greater.*
    a. *Can you state for the record whether it is prudent to enter a winter season expecting "manageable" energy shortfall with an already constrained energy supply?*
    b. *Can you state for the record the magnitude and severity of the greater risks for 2032? What actions or steps need to be taken?*
    c. *Recognizing that risks are "manageable" in 2027 and greater in 2032, can you explain whether it is in the best interest of ISO-NE, its wholesale customers, and the retail end users to retain EMT for purposes of electric reliability and energy adequacy? Are the costs of retaining EMT through 2032, whether through a market mechanism or out of market contract, greater than the risk of electric or natural gas system blackout?*
    d. *Can you state for the record whether retaining EMT and arranging for shipments of LNG will result in lower emissions compared to operating oil units?*

Response:

New England is energy-constrained during cold weather periods and that can result in the risk of energy shortfalls. The level of risk going forward will depend on a variety of factors, as described above. The 21-day energy forecast tool we have developed will provide the ISO and the region with information on specific timeframes when an energy shortfall might occur. That information would allow the ISO, utilities, resources owners, and state officials, to take action in a timely manner to mitigate, or possibly eliminate a potential energy shortfall. The scope of those actions could include actions to increase supply (e.g., generators replenishing stored fuels) or to reduce demand (e.g., public appeals to reduce the use of nonessential lighting or other electrical appliances).

The ISO has no authority to retain the Everett Marine Terminal beyond the FERC-approved cost-of-service agreement with the Mystic generating units, which expires on June 1, 2024. Our probabilistic studies with the Electric Power Research Institute (EPRI) have not shown a definitive need for the facility to maintain electric system reliability. Nevertheless, considering the significant challenges of developing new energy infrastructure, and the longer term uncertainty with regard to the aforementioned variables (demand, new supply, and retirements) we do see a benefit to the region to maintaining the EMT facility. The EPRI study and the new Probabilistic Energy Adequacy Tool (PEAT) provide a mechanism for the region to evaluate the risks associated with retirements (or additions) of energy infrastructure.

The retirement of a gas-fired generator (whether supplied by pipeline gas or LNG) would result in a shift to other resources, which could include oil-fired generators, or gas-fired generators that can switch to oil as a back-up fuel. During cold weather, the region typically would already be burning oil for power generation if natural gas prices were high. The emissions from the generation fleet would change based on whatever resources are economic in the market.

The Honorable Kelly Armstrong

1. *Markets often have difficulty sending the appropriate price signals that account for reliability to support the development of new or improvement of existing dispatchable resources. Capacity markets appear to set prices below efficient levels, and some lack a demand curve that accurately represents needed capacity, leading to questions about resource adequacy.*
    a. *Has your organization evaluated the role Planning Resource Auctions play in sending price signals?*
    b. *Does the current demand curve establish clearing prices that are alienated from the worth of capacity and reliability?*
    c. *If your organization is in the process of restructuring a demand curve, will it be implemented in a timeline aggressive enough to send appropriate price signals to dispatchable resources?*

Response:

We design the wholesale electricity markets to procure the resources needed to serve consumers' demand for electricity and to meet reliability standards. The wholesale markets signal the need for investment in existing or new resources depending on whether the market is long or short on resources. We currently have sufficient supply to meet projected demand, and we are enhancing our capacity accreditation methodology to ensure that we have sufficient capacity to meet reliability needs. In addition, we are working with our stakeholders to evaluate a potential transition to prompt, seasonal auction that should bring further reliability improvements and market efficiencies to the region. This effort is still in the early stages of consideration and will ultimately require FERC approval.

2. *Weather-dependent generation is penetrating the generation mix at an increasing rate.*
    a. *Has your organization evaluated accreditation processes for these resources?*
        i. *If so, does this accreditation consider the weather risks associated with weather-dependent generation?*
    b. *Is your organization evaluating seasonal accreditation and/or effective load carrying capability for weather-dependent generation?*
    c. *Does your organization have the same reliability standards for weather-dependent generation as it does for dispatchable resources?*
    d. *Should changes to capacity accreditation go into effect before other changes to the capacity market?*

Response:

ISO New England is evaluating accreditation for all resources participating in the capacity market, including weather-dependent resources. The proposed Resource Capacity Accreditation (RCA) changes would evaluate the contribution of each resource to meeting system demand when the power system is stressed and accredit that resource accordingly. In general, the markets are structured so that we pay resources based on the services they provide to the grid, not based on their resource type. We plan to implement the RCA changes for Forward Capacity Auction No. 19, which is scheduled to take place in 2026 and will procure capacity for the 2028–2029 timeframe. We are not planning other capacity market changes ahead of the RCA changes.

3. *Traditional load forecasting tools rely on customer history and interactions to approximate demand needs, including peak consumption.*
    a. *To what extent does your organization consider external studies or critiques of load forecasting models when acquiring capacity?*

Response:

ISO New England updates the forecasts used for system planning on an annual basis and we continuously evaluate the tools and methodology to develop the load forecasts. We do incorporate external data into this process. Each year, the ISO receives economic forecast information from Moody's Analytics as an input to our forecasting process and we review the forecast we develop with New England stakeholders through the NEPOOL Load Forecasting Committee and the ISO New England Planning Advisory Committee. We work with the New England states and utilities to develop the discrete energy efficiency, photovoltaic, and electrification forecasts that are part of the ISO's overall forecast. In addition, each year, the ISO files information with FERC pertaining to the forecasted load and the installed capacity requirement for each Forward Capacity Auction.