UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Federal and State Issues Collaborative	)	**AD24-7-000**
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Statement of Gordon van Welie, President and CEO, ISO New England

Good morning, FERC Commissioners and State Commissioners. My name is Gordon van Welie and I am the President and CEO of ISO New England. Thank you for the opportunity to speak with you about gas-electric coordination. Today, I am wearing two hats: I am here on behalf of ISO New England to provide a New England view on this issue, and I am here as the Chair of the ISO/RTO Council (IRC) to provide the perspective of the nine North American independent system operators (ISOs) and regional transmission organizations (RTOs).[1] Through wide-area infrastructure planning, as well as wide-area balancing of supply and demand, IRC members help North America's power system operate reliably, adapt to extreme weather, and maintain affordability.

ISO New England is the independent, nonprofit corporation responsible for operating a competitive wholesale electricity market across the six New England states and we plan the transmission system to ensure that it can meet the future demand for electricity in the region. Our job is to reliably plan and operate the power system to meet reliability standards set by the North

[1] The IRC comprises the Alberta Electric System Operator (AESO), the California Independent System Operator Corporation (California ISO), Electric Reliability Council of Texas, Inc. (ERCOT), the Independent Electricity System Operator (IESO) of Ontario, ISO New England, Inc. (ISO-NE), Midcontinent Independent System Operator, Inc., (MISO), New York Independent System Operator, Inc. (NYISO), PJM Interconnection, L.L.C. (PJM), and Southwest Power Pool, Inc. (SPP).

American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC).

I would like to make a few points about gas-electric coordination that cut across virtually all ISOs/RTOs. As we have observed most notably in several recent winter events (*i.e.*, winter storms Uri and Elliott), the natural gas and electric systems are highly interdependent, and we expect that this will become even more apparent as the electric system continues to shift toward higher penetrations of intermittent resources. This interdependency exists as the gas system relies on the electric system for power supplies, while the electric system relies on the gas system for electric power generation; over time, the two systems have effectively become one system. Additionally, the effectiveness of winterization efforts (both on the gas side and the electric side) will be a significant factor in reliability of both systems in the future as evidenced by the recent winter storms.

Further, the changing electric demand profiles, the growth of electric demand, and the evolution of the resource mix to more weather dependent resources, directly impact the operation of the gas system. For example, the increasing number of intermittent resources on the electric grid (both behind and in front of the meter) means that the instantaneous loading of the gas system, and the overall average capacity factor, becomes more volatile as the gas system needs to respond to help balance the electric grid. Finally, the gas and electric markets have fundamental differences that require acknowledgement and specific actions to mitigate and/or account for those differences. For example, the electric system is planned and built on forecast load, while the gas system is designed and constructed based on long-term contracts from customers. This makes it difficult for the gas and the electric systems to function efficiently as interdependent systems.

Both the IRC and the ISO New England comments fall under the issues I have outlined above. I would now like to comment on behalf of the IRC, recognizing that some issues may vary by jurisdiction.

ISOs and RTOs have established strong working relationships with interstate pipeline operators, fostering close gas-electric coordination and developing tools to enhance gas system situational awareness. However, several areas warrant improvement. I will note that many of these issues were addressed in a whitepaper entitled "Strategies for Enhanced Gas-Electric Coordination: A Blueprint for National Progress" that was produced by ISO-NE, PJM, MISO, and SPP in February of 2024.

- **Address Co-Dependency Vulnerabilities and the Linkage to Differences in Planning Standards and Economic Recovery Mechanisms**: The bulk electric system (BES) and the gas system increasingly rely on each other to operate reliably. Unlike the BES, critical gas infrastructure often depends on single gas system elements or sources, and failures of these elements or sources can result in gas system reliability issues that may impact gas supplies to end use customers, including gas-fired generators connected to the BES. The BES is explicitly planned to meet mandatory reliability standards and financed through a variety of regulatory mechanisms to meet forecast demand from all consumers, whereas the gas system is not planned to meet forecast demand from all users and is financed through voluntary contracts that are approved by regulators. The different regulatory models have resulted in inefficiencies and reliability risks. Growth in the demand for electricity, coupled with the changing electric system resource mix, is increasing operational volatility and risks for both systems, particularly for high impact tail risk events in the winter. Pipeline operators, gas suppliers, ISOs/RTOs, and electric distribution utilities must collaborate to ensure redundant power for critical gas facilities. Given that electrification mandates have contributed to this dependency, coordination with environmental regulators at both state and federal levels is essential to ensure adequate redundancy for critical infrastructure.

- **Enhance Scheduling Flexibility:** Generators experience inconsistent scheduling flexibility when responding to RTO dispatch, particularly under constrained conditions. Most often, the cause is the lack of sufficient gas system pressure due to a combination of insufficient gas supply and the high demand on a gas system that has not been built to supply the demand of both gas and electric users. This problem is exacerbated by multi-day natural gas trading limitations during weekends and holidays.

- **Enhance Gas Trading Liquidity:** Current multi-day natural gas trading limitations during weekends and holidays hinder responsiveness to demand fluctuations, impacting grid reliability and efficiency. While no single entity has complete jurisdiction, FERC and NARUC can leverage their convening and regulatory authority to facilitate proactive solutions, such as enhanced liquidity in gas markets during critical winter periods.

- **Reform Force Majeure:** The current North American Standards Board (NAESB) base contract language allows for the declaration of a Force Majeure by gas producers when well head freeze offs occur and result in significant production losses. The IRC recommends narrowing force majeure definitions to incentivize proactive wellhead winterization. FERC and the states should issue a policy statement supporting enhanced force majeure provisions in commodity contracts and allowing review of whether reasonable mitigation measures (*e.g.*, weatherization) were implemented during force majeure events.

- **Gas Production Weatherization:** The jurisdictional gap in the oversight of the operations of the upstream natural gas sector wellhead regulation presents a reliability challenge. States should leverage their existing safety oversight to encompass well head reliability. A national forum could establish regional weatherization guidelines for wellhead operations, ensuring consistent reliability standards and a level playing field across all jurisdictions. Of note, there has been recent positive movement by gas producers in the area of facility winterization including the December 2024 Recommended Practices initiative developed by the Marcellus Shale Coalition, which is designed to provide consistent winterization guidance for its members.
- **Enhance Real-time Communication**: Direct communication between RTO/ISO control rooms and gas pipeline control rooms should be prioritized and encouraged to allow for real-time information sharing and coordination of planned outages, thereby enhancing situational awareness and supporting system reliability by ensuring free and open lines of communication between operators of the electric system and operators of the gas system.

With respect to ISO New England, the region is energy-constrained and has grappled with gas-electric infrastructure challenges for over two decades. ISO New England has significant operational experience with gas-electric interdependencies, building strong relationships with the operators of the interstate gas pipeline system and developing tools to enhance our situational awareness of the gas system. ISO New England is now a leader in gas-electric coordination.

Natural gas generators supply about half of New England's electricity needs on an annual basis, yet the interstate pipelines serving the region are not designed to serve peak demand from both home heating and power generation. During periods of extended cold weather, New England has long been challenged by our location at the end of the pipeline and limited gas infrastructure to meet the combined peak demand from heating customers and power generation. This physical constraint drives up gas prices, forcing the region to rely on more expensive oil and liquefied natural gas (LNG). Furthermore, the Jones Act restricts access to domestically sourced LNG, increasing the region's dependence on global LNG markets and exacerbating price volatility in both natural gas and wholesale electricity markets.

The electricity markets in New England are set up as short-term spot markets to price prevailing supply and demand conditions in each of the core markets, *i.e.* the energy, ancillary and capacity markets. They are required to be resource neutral, and the primary market design objective is to compensate resources for the electrical energy provided, and in proportion to their timely contribution to the reliability of the BES (as illustrated in multi-settlement energy market design, the Pay-for-Performance penalties and planned marginal accreditation improvements in the capacity market). The wholesale market design creates strong financial incentives for timely electric energy production, and in turn strong financial incentives for generators to firm up fuel supplies, but it does not mandate firm fuel, and if it did, it would likely result in over-investment in fuel infrastructure. This issue was litigated at FERC over a decade ago between the New England Power Generators Association and ISO New England with FERC ruling that, beyond their day-ahead commitment, generators may be considered physically unavailable if they cannot obtain fuel at any price.

FERC re-affirmed the primacy of the "resource neutrality" principle in wholesale market design. To illustrate this point further, a gas generator that utilizes a constrained gas system that cannot always supply gas is treated comparably with a wind generator that does not always have wind available, a pumped-hydro generator that has limited pondage, or a short duration lithium-ion battery. The consequence was that ISO New England moved in the direction of sharpening performance incentives for electric energy outputs without specifying the means (or the energy inputs) by which generators produce those outputs.

As mentioned earlier, gas pipeline investments are based on voluntary long-term contracts with customers. Electricity markets operate on shorter timescales and cannot provide economic certainty and cost recovery for merchant generators to commit to 20 plus year pipeline contracts, particularly in the context of regional policies that will gradually displace electricity production from gas generators and increase the cost of emissions. Therefore, it is not economically rational for merchant gas generators in restructured regions to invest in expensive new firm gas transportation or for that matter, new gas storage facilities. There are less capital-intensive options available, *e.g*. dual fueling (assuming it can be permitted and sited), or utilization of existing LNG terminals to import LNG, or foregoing electricity market revenues and accepting the penalties when fuel is not available. Consequently, gas generators either don't run during periods when the pipelines are constrained, or they switch to more expensive fuels to produce electricity. These generators are typically the marginal units during these periods and set the clearing price, causing wholesale electricity prices to increase substantially. This price effect causes wholesale load to consider how best to hedge itself from this intermittent volatility, driving discussions amongst regional policy makers about whether to invest in new gas pipeline infrastructure, or alternative resources (*e.g*. offshore wind). Importantly, while these price signals produce information about the constraints on the gas system, they cannot reveal the latent resilience risks embedded in a gas system that is vulnerable to single element contingencies. This can only be revealed by studies such as the one recently conducted by the NPCC (see below).

As is described in more detail below, the economic conundrum also applies to the regional LNG facilities which rely on a peaky and intermittent demand for LNG. In summary, while peak gas demand may grow over time (depending on how the energy transition is managed and whether economically viable long duration energy storage alternatives can be developed), average gas demand is likely to drop, resulting in a cost recovery problem for both existing and new investments in gas infrastructure.

As mentioned previously, wholesale market incentives will not directly drive long-term investments in new gas infrastructure, but they can incentivize generators to firm up their fuel supplies. For example, in New England, approximately 43% of the region's natural gas fleet also has dual fuel capability. Current market incentives include pay-for-performance, and ancillary services like the recently implemented Day-Ahead Ancillary Services Initiative. In addition, ISO New England's on-going effort to enhance its resource accreditation methods seeks to model the region's gas constraints in a manner that aims to incentivize short-term firm gas contracting (primarily through the purchase of LNG options from existing LNG facilities, which will help their economic viability) and/or additional dual fuel capability which could serve to bolster the readiness of gas fired generation during the winter when gas supplies are tightest.

As we look ahead, changing patterns of electricity generation and consumption mean these resources and services play an increasingly important role in progressively complex system operations. Most natural-gas-fired plants can change output quickly. This helps to balance variations in output from increasing levels of intermittent power resources, effectively transferring production volatility from the electric system to the gas system. Yet, unlike the electric transmission system, the gas system lacks centralized planning and cost recovery mechanisms for peak demand, including electric generation needs. This lack of coordinated planning, despite the increasing interdependence of gas and electricity, is a significant vulnerability. This presents a complex, unaddressed reliability problem to federal and state policy makers and regulators, that was not contemplated when the Federal Power Act and the Natural Gas Act were promulgated, or when the electric industry was unbundled and restructured in the late 1990s.

While the New England region has three LNG facilities (one in Everett, Massachusetts; one in St. John, New Brunswick, Canada; and the Northeast Gateway buoy system located 13 miles off the coast of Massachusetts) to help balance the system, their economic viability remains challenging because of the peaky and intermittent demand for LNG. For example, the Everett facility faced closure before securing contracts with local distribution companies and the Northeast Gateway has only received 5 cargoes over the past 15 years. Ensuring cost recovery for gas infrastructure is critical and requires ongoing dialogue between the natural gas and electric industries, in coordination with state and federal regulators.

In New England, state officials and policy makers are seeking to balance three objectives that will shape regional infrastructure outcomes at both the wholesale and retail levels. These objectives are reliability, cost/affordability and environmental considerations (including reducing carbon emissions). ISO New England is only responsible for executing its mission to operate the bulk power system reliably, plan the electric transmission system to meet reliability standards, and design/administer the spot wholesale electricity markets to ensure efficient pricing and in accordance with NPCC/NERC reliability criteria. This means that ISO New England is not the right entity to manage the tradeoffs resulting from the three objectives which may be in tension with one another.

Further, our role in maintaining bulk power system reliability means that we must instantaneously balance demand and supply for electricity and that includes reducing bulk power system demand when supply cannot meet demand in real-time (*i.e.*, load shedding). This can cause severe knock-on effects to the retail electricity and gas systems. These reliability risks may be outside of the current reliability standards (*i.e.*, high impact low probability risks) and policy makers/regulators will need to evaluate whether more stringent reliability standards may be warranted. ISO New England has developed sophisticated tools to both quantify and forewarn the region and federal/state officials of evolving energy adequacy risks and is in the process of developing a new energy adequacy metric, the Regional Energy Shortfall Threshold (REST), to measure energy adequacy risks.

Emergency preparedness exercises initiated by ISO New England with New England electric and gas distribution companies after Winter Storm Uri, highlighted that widespread bulk electric system load shedding, while manageable on the electric grid, can trigger catastrophic "flameouts" on gas distribution systems due to mass furnace restarts after the rotation of the electric load shedding from one set of distribution feeders to the next. This underscores the urgent need for improved coordination and planning of gas and electric infrastructure, to ensure that the overall energy system remains resilient.

Finally, the Northeast Power Coordinating Council in January released a study of the reliability of the Northeast (New England and New York) gas system.[2] In that study, the NPCC points to the vulnerability of the Northeast gas system during severe cold weather events to single element gas system contingencies (*e.g.,* the loss of a large pipeline, compressor stations or storage facility), and by inference, the vulnerability of the interdependent gas and electric systems to those contingencies. This underscores the asymmetric nature of planning on the electric system and the gas system. The electric system is planned and operated to survive single contingencies

[2] https://www.npcc.org/news/npcc-northeast-gas-electric-system-study

(*e.g.*, the loss of the largest generator or the largest transmission line). This is not the case for the gas system, in part because of the lack of comparable reliability standards.

The IRC and ISO New England appreciate FERC and NARUC's focus on this important issue. ISOs and RTOs have observed a high degree of interdependency between the natural gas and electric systems in several recent winter weather events, and this trend is expected to continue as the electric system continues to shift toward higher penetrations of intermittent and limited-duration resources. The gas system relies on the electric system to power gas production, processing, transmission and distribution equipment while the electric system relies on the gas system to fuel gas-fired electric power generation; over time, the two systems have effectively become one system.

With respect to ISO New England, gas is likely to remain the primary "balancing fuel" for the foreseeable future, and as long as there are constraints on the supply of gas, the region will need workarounds to those constraints. Large scale deployment of weather dependent renewables will help reduce the gas constraint, but the region will always be dependent on some form of long duration energy storage. Therefore, the region needs to make sure there is a plan in place to ensure energy adequacy – including retaining sufficient infrastructure, long duration energy or fuel storage, and stabilizing fuel supply chains. These challenges will continue until a robust regional solution is determined to address the co-dependency vulnerabilities in the electric and gas systems and associated supply chains.