# NPCC Northeast Gas/Electric System Study

# Summary Report

***(January 3, 2025*)**

## INTRODUCTION

In November 2023, the Northeast Power Coordinating Council (NPCC) announced the launch of the NPCC Northeast Gas/Electric System Study. The study focused on the New York and New England areas. Levitan & Associates (LAI) was selected to conduct the analysis. Three winter periods were evaluated: 2024/25 (short-term), 2027/28 (mid-term) and 2032/33 (long-term).

A Steering Committee, consisting of NPCC, the New York Independent System Operator (NYISO), Independent System Operator of New England (ISO-NE), the North American Electric Reliability Corporation (NERC), and the Northeast Gas Association (NGA) was formed to support the evaluation. Natural gas supply and pipeline constraints were evaluated during extreme and protracted winter weather events during the peak heating season, from December through February.

The Full Report will be posted by January 21, 2025 at: https://www.npcc.org/resources.

## STUDY GOALS

1. Quantify the physical capability of the consolidated network of pipeline and natural gas storage infrastructure to serve gas-fired generation under cold weather conditions over the study horizon;
2. Assess the resilience of gas infrastructure to withstand postulated gas and electric contingencies while continuing to serve Local Distribution Company (LDC) customers and scheduled gas-fired generation under cold and milder weather conditions;
3. Assess mitigation potential ascribable to dual fuel generation, electric storage, and/or other dispatchable thermal units when contingencies occur; and,
4. Identify key uncertainty variables and risk factors affecting gas/electric interdependencies.

## KEY FINDINGS

- ❑ Hydraulic modeling confirms that the New York and New England natural gas infrastructure is fully utilized during the modeled extreme cold weather period. However, as with any system, there are constraints. Should any of the modeled gas-side contingencies occur, the constraints on the system would be exacerbated, thereby increasing reliance on oil-fired generation to ensure electric grid reliability.

- ❑ Most gas-fired generators operating in New York and New England do not hold firm transportation entitlements. The absence of firm entitlements can expose those generators to gas supply curtailment or interruption when pipeline congestion materializes during the peak heating season. Maintaining dual fuel capability, coupled with liquid fuel storage and resupply arrangements, is a viable way to satisfy fuel assurance objectives for electric system reliability during the modeled hydraulic periods.

- Events resulting in the near or total cessation of natural gas throughput, for example, a pipeline line break or the loss of a strategically located compressor station, while having a low probability of occurrence, may potentially cause catastrophic impacts for downstream customers.

- Extreme cold weather conditions lasting longer than the three-day periods modeled in this study could add additional stress to the network of gas pipeline and storage and oil storage infrastructure in New York and New England, thereby heightening electric reliability challenges if oil inventory cannot be replenished on a timely basis.

- Across the breadth of gas contingencies evaluated in this study, the hydraulic results show that electric system operators would have adequate time to safely shut a generating unit down, except for a line break immediately upstream of an online generator. Contingency events that limit the flow of gas supplies into New York and New England or cause a diminution of compression within the Study Region are rare, but more likely to occur than a line break. With few exceptions, the loss of strategically located compression could generally be mitigated through increased horsepower utilization or increased flows through interconnections with other pipelines. The pressure decay following a compressor station outage would not likely cause damage to downstream turbines, and would allow continued gas flow, giving plant operators sufficient time to ramp down gas intake for the avoidance of harm.

- In both New England and New York, incremental renewable generation and electric storage capacity was assumed in the mid-term and long-term cases in accordance with the various states' environmental goals. Intermittent renewable resources require additional load-following from dispatchable resources such as electric storage and gas and oil-fired generation.
    - In New England, the buildout of renewables through 2032 leads to as much as 4.6 GW to 7.1 GW of gas-fired generation ramping required over two to eight hours, respectively.
    - In New York, the buildout of renewables leads to as much as a 7.1 GW ramping need over two hours for gas-fired generation.

  Ramping of gas-fired generation has historically been far lower than revealed in the long-term electric sector modeling. Transient hydraulic modeling indicates that higher ramps in the long-term can generally be accommodated.

- The constrained baseline operating conditions on the gas systems in New England and New York during cold weather periods mean that limited gas-fired generation options are expected to be available to respond to electric contingencies, which could take the form of a sudden nuclear plant or HVDC transmission outage.

**New England**

- Both Liquified Natural Gas (LNG) importers - the Constellation Everett Marine Terminal (EMT) and Repsol Saint John – are an integral part of the gas-fired generators' ability to satisfy fuel assurance objectives.

- In New England, operating flexibility throughout the peak heating season is supported by the scheduling of displacement services associated with gas supplies from Repsol Saint John and/or Constellation EMT, which bolster deliverability at the eastern end of the system pipelines. These deliveries give pipeline operators valuable scheduling flexibility since they displace the need for conventional flows west-to-east into New England. In modeling New England's commodity balance, about 1.2 Bcf/d of LNG is available on a coincident basis: two-thirds from Repsol Saint John (0.8 Bcf/d) and one-third from Constellation EMT (0.4 Bcf/d). This incremental gas supply can be used to fuel approximately 8,000 MW of gas-fired generation. Almost one-half of ISO-NE's gas capable generation is gas-only. Absent Constellation EMT, Repsol Saint John could be used to fuel about 5,400 MW of gas-fired generation. Absent Repsol Saint John, about 2,600 MW could be served by Constellation EMT, including gas-fired generation in southern New England.
    - Removing Constellation EMT from the gas supply mix reduces the deliverability of the gas system by 400 MDth/d. Under cold weather conditions, when Repsol Saint John is sending out approximately 800 MDth/d and the west-to-east pipeline segments are fully utilized, no additional supply can be sourced from either of these paths. As a result, if Constellation EMT is not available, generators will have to replace up to 400 MDth/d of gas generation with an equivalent amount of oil generation during the modeled cold weather conditions. With the scheduled retirements of oil plants and the absence of Constellation EMT in the modeled long-term scenario, capacity deficiency actions might be needed to maintain electric system reliability.

    - If, for whatever reason, Constellation EMT is not available, gas sendout from Repsol Saint John would still be deliverable into the eastern ends of the system. However, Repsol Saint John is an imperfect substitute for Constellation EMT because it does not deliver gas into the eastern ends of the system at the same points. Constellation EMT is located on Algonquin's J System in Cambridge, MA, which is downstream of the constraint point at the lateral header. Constellation EMT's location is ideal because it provides both pressure support and flow on an instantaneous basis whereas Repsol Saint John cannot.

    - Deliverability benefits related to counterflow at the back end of the Tennessee and Algonquin systems are predicated on Repsol's ability to pack the M&N pipeline during cold snaps, thereby ensuring instantaneous delivery each morning. Under less extreme weather conditions, when the need for line pack is not anticipated the next gas day, it could be many hours before supplies from Repsol could be available to the heart of the market center in New England in the event of a gas contingency event. In contrast, Constellation EMT's location would provide both pressure and flow benefits in an instant.

**New York**

- The consolidated pipeline network in upstate New York is constrained during cold snaps, limiting the availability of gas for generation in the Hudson Valley and the Capital District.

- In the downstate market on the New York Facilities System – New York City and Long Island - the existing gas infrastructure is unable to meet demand for nearly all generators during a cold snap. Operating risk in New York City and Long Island is already mitigated because scheduled generation mostly operates on oil. Recent experience with Winter Storm Elliott reveals the fragility of the New York Facilities System when upstream supply is materially reduced.

- During more temperate weather conditions, when more gas-fired generation is scheduled on the New York Facilities System, the loss of compression or mainline deliverability on any one pipeline serving Con Edison and/or National Grid would likely result in the loss of significant gas-fired generation. Under the most disruptive perturbations, about 3,600 MW of gas-fired generation in New York City and about 1,000 MW of gas-fired generation on Long Island would have gas service interrupted. Nearly all of these generators are dual fuel capable. The New York State Reliability Council has local reliability rules in place to ensure that oil auto-swap capabilities or minimum oil burn is in place for baseload facilities to mitigate the impacts of a gas contingency on electric reliability.

**KEY RISK FACTORS**

1. The structure of wholesale energy markets in regard to the financial and market incentives underlying a generator's willingness to pay for firm transportation entitlements, or firm gas supply contracts for either LNG or pipeline gas continues to evolve but may require continued refinement to meet electric grid reliability objectives over the long term. LNG importers have been unwilling to tolerate scheduling and LNG procurement risk that they would need to bear in order to arbitrage price spreads between global LNG prices and gas and electric prices in New England. There are valid reasons for LNG importers to avoid speculative cargoes. For gas-fired generators to rely on LNG for deliverability during the peak heating season, expensive call options will likely be needed to ensure adequate compensation. What is physically possible and commercially reasonable are likely distinctly different.
2. Since most generators do not have firm transportation entitlements, the ability of pipelines to provide intra-day scheduling flexibility to accommodate the twice daily ramp during cold snaps should be questioned.
3. Additional retirements of oil-fired generation could further limit ISO-NE's and NYISO's options during cold weather or contingency events. Aging residual oil-fired steam turbine

generators cannot respond quickly to contingencies when offline, but they have expansive liquid storage capability that provides secure fuel supply during cold weather conditions. Conversely, aging fast-start generation, particularly in downstate New York, represents the fossil resource best equipped to respond to large and unexpected losses in electric supply. Fast-start generation may also be necessary to replace gas-only plants that trip offline under a gas supply contingency.

4. The contingency analysis focus has been on the physical capability of the pipeline network to continue to deliver scheduled gas to generators after an adverse event. The contingency analysis performed in the hydraulic modeling suite does not explicitly contemplate the array of pipeline operator actions that could be implemented to reduce deliveries to protect system integrity and maximize the ability to meet contractual obligations. Instead, the contingency analysis incorporates an estimation of what may be physically possible.
5. Assumed load growth over the long term reflects aggressive heating and transportation electrification and that will cause winter peak demand to grow substantially by the long-term forecast period. The pace of heating and transportation electrification may be reduced relative to ISO-NE, NYISO, and their respective states' expectations due to changes in federal and state policies as well as customer choices. Reduced electricity demand growth would lessen the burden that gas-fired generation places on gas infrastructure in the Study Region. On the other hand, renewable energy additions, in particular, offshore wind along the New England coastline and the New York Bight has the potential to materially lessen reliance on oil and gas during the peak heating season. The pace of electrifying the heating and transportation sectors relative to decarbonizing electric supply will affect the operational stresses on the gas infrastructure available to serve gas-fired generation over the long term. Uncertainty about the pace, amount and inevitability of electrification, electric vehicles and offshore wind in the years ahead may intensify operational stresses on the gas infrastructure available to serve gas-fired generation over the medium and long term.