ANALYSIS GROUP

Fuel and Energy Security In New York State

An Assessment of Winter Operational Risks for a Power System in Transition

DRAFT REPORT

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Acknowledgments

This report has been prepared at the request of the New York Independent System Operator, Inc. (NYISO), to conduct a forward-looking assessment of the fuel and energy security of the New York electric grid during winter operations.

This is an independent report by Paul J. Hibbard, Joe Cavicchi, Grace Howland, Jack Graham and Marios Vafiadis of Analysis Group, Inc. (Analysis Group, or AG), and reflects the judgment of the authors alone. They wish to express their sincere appreciation for the assistance and input from the NYISO and its market participants and stakeholders.

About the Authors

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About Analysis Group

Analysis Group is one of the largest international economic consulting firms, with more than 1,000 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, health care analytics, and strategy to top law firms, Fortune Global 500 companies, government agencies, and other clients worldwide.

Analysis Group's energy and environment practice area is distinguished by expertise in economics, finance, market modeling and analysis, regulatory issues, and public policy, as well as deep experience in environmental economics and energy infrastructure development. Analysis Group has worked for a wide variety of clients including (among others) energy producers, suppliers and consumers, utilities, regulatory commissions and other federal and state agencies, tribal governments, power-system operators, foundations, financial institutions, and start-up companies.

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I. Executive Summary

A. Background and Study Context

The NYISO is responsible for the reliable planning and operation of the state's bulk power system and the design and administration of the state's competitive wholesale markets. For more than twenty years, the NYISO has maintained system reliability and improved its competitive market designs, while addressing - from both planning and operational perspectives - continuous changes in the infrastructure, fuels, and policies that drive evolution of the power grid. Two key factors have dominated this evolution in recent years. The first is the emergence of low cost natural gas - with the arrival of shale gas - as the fuel of choice for new generating infrastructure development. The second is the transition underway to decarbonize the state's economy, through energy, environmental and climate-related policies together with economic considerations associated with the relative costs of certain renewable resource options.

These changes have significantly impacted the resource fleet in New York and have driven a greater dependence on natural gas and renewable resources for power system operations.[1] Reliance on gas fired or dual-fuel units with gas as their primary fuel has increased significantly. In terms of annual generating capability, since 2000, the production capability of units with natural gas as the primary fuel has increased from 47 percent to over 60 percent (Figure ES-1). Over the same period, the generating capacity from renewable resources (wind and solar) has increased from being negligible to over 5% today and is expected to grow significantly by 2040.

Over this period the increased reliance on natural gas and renewable resources in New York has contributed to meaningful benefits, as both the price of electricity and the emissions associated with power system operations have generally declined.[2] These benefits have been largely driven by the displacement of older, less efficient and more polluting fossil fueled generation with newer, more efficient and less polluting resource options.

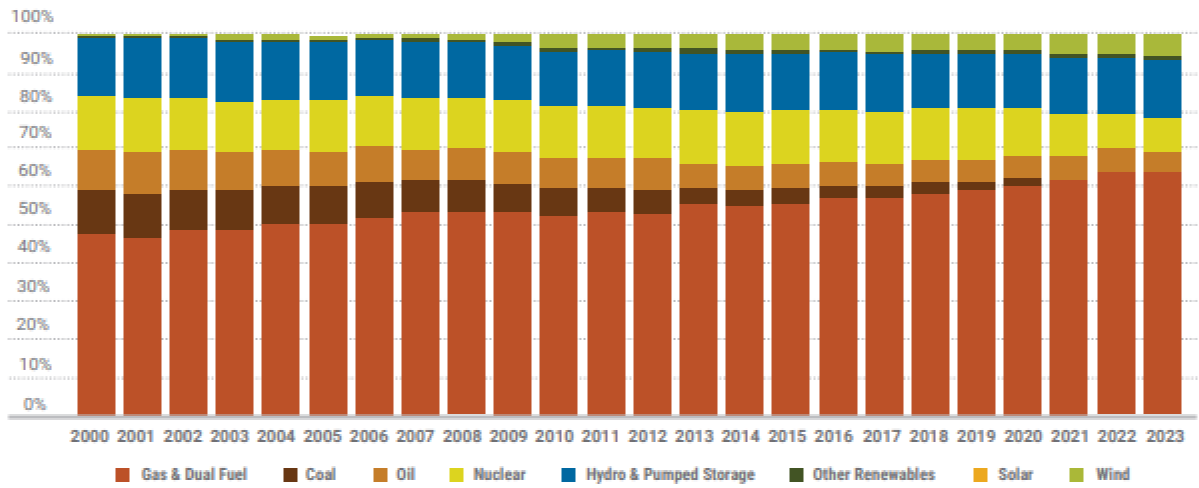
The increasing reliance on natural gas (most of which is contracted for on a non-firm basis and in some cases backed up by oil-fired capability) and weather-dependent renewables can be expected to increase the challenges associated with reliable system operations. Moreover, growing winter electricity demand, potential fossil (including dual fuel) generation resource retirements and significant changes in generation fleet (both in terms of resource locations and operating characteristics) present challenges that require careful evaluation. Recognizing the ongoing pace of change and unique winter weather operational demands, the NYISO asked Analysis Group to update and expand its 2019 fuel and energy security risk assessment (FESA).[3] This 2023 analysis evaluates the NYISO's system projected supply/demand balance for three future winters—2023/2024, 2026/2027 and 2030/2031— under conditions that include a seventeen-day period of extended cold weather, including an extreme cold snap during three of those days.

[1] New York Independent System Operator, "2023 Power Trends A Balanced Approach to a Clean and Reliable Grid," p. 39 (hereafter "NYISO Power Trends 2023"), available at https://www.nyiso.com/documents/20142/2223020/2023-Power-Trends.pdf/7f7111e6-8883-7b10-f313-d11418f12fbf?t=1686132123808.

[2] New York Independent System Operator, "Reliability and Greener Grid, Power Trends 2019," p. 33 (hereafter "NYISO Power Trends 2019"), available at https://www.nyiso.com/documents/20142/2223020/2019-Power-Trends-Report.pdf/0e8d65ee-820c-a718-452c-6c59b2d4818b?t=1556800999122.

[3] Hibbard, Paul and Wu, Charles, Fuel and Energy Security In New York State, "An Assessment of Winter Operational Risks for a Power System in Transition," Final Report, Analysis Group, November 2019, (hereafter, "Analysis Group 2019 FESA" or "2019 FESA").

Figure ES-1: New York State Fuel Mix Trends: Capacity 2000-2023



Source: NYISO Power Trends 2023, page 39.

Several factors confirm the finding from the 2019 FESA that continued monitoring and analysis of the ongoing transition of the resource fleet and its potential impact on the reliable operation of the NYISO power grid remain important.

1. In general, increased dependence on any one fuel has the potential to decrease the diversity of power generation, increase the risks of disruption, and reduce the reliability benefits that flow from greater diversity (in the fuel source, location, size, and operational modes of power system generating resources).
2. In particular, the growth in reliance on natural gas and renewables has coincided with the retirement of coal and oil resources (fuels which are which are typically stored on-site), and the potential - or likely - continued retirement of fossil-fuel resources reducing overall system-wide fuel diversity.
3. The state's continued efforts to reduce emissions of harmful pollutants and decarbonize all sectors of the economy - most significantly through the Climate Leadership and Community Protection Act (CLCPA)[4] - have potentially two significant outcomes: 1) a continued decline in oil-fired and other fossil-fired generation capacity that is currently critical for reliable winter system operations (especially downstate), and 2) a potentially significant increase in (and change in the shape of) demand for electricity, due to electrification of the building, transportation, and other sectors of the economy that will create additional system reliability and operational challenges.[5]
4. Finally, despite the need to reduce fossil fuel combustion in total across all sectors to meet the state's GHG emission reduction targets, fossil-fired generation (including natural gas) and/or other dispatchable emission free resources with similar operating capabilities will be needed for reliable power system operations

[4] Chapter 106 of the Law of the State of New York of 2019.

[5] Some of the standards established by the CLCPA include: (1) a goal to reduce GHG emissions 85% over 1990 levels by 2050, with an incremental target of at least a 40% reduction by 2030; (2) producing 70% of electricity from renewable resources by 2030 and 100% from zero-carbon resources by 2040; (3) increasing energy efficiency by 23% over 2012 levels; (4) building 6 GW of distributed solar by 2025, 3 GW of energy storage by 2035, and 9 GW of offshore wind by 2035; (5) electrification of the transportation sector, as well as water and space heating in buildings.

throughout this transition, to support electrification of other sectors, and help manage the greater variability of increasing quantities of weather-dependent renewable generating resources.

The state of New York has witnessed significant changes over the last two decades, driven primarily by public policies and the emergence of natural gas as the fuel of choice for electricity generation. The state is now entering an ambitious and challenging period of transition - one that may require an unprecedented level and pace of change in power system infrastructure and operations to achieve the GHG reductions in all sectors of the economy required by the CLCPA. In this context, it is a good time for the NYISO, electricity market participants, and stakeholders to –carefully evaluate potential impacts- associated with winter system operations, and to explore the key factors that will likely drive how these impacts may change over time.

B. Study Purpose and Method

1. Purpose

The mix of fuels used to generate electricity affects both the reliability and resilience of the bulk electric system. A balanced array of resources enables the system to better address issues such as price volatility, fuel availability and stressed/abnormal operating conditions. New York's electric generation fleet has historically been comprised of a relatively diverse mix of fuel types.

The confluence of technological advancements, environmental and economic considerations, and public policies are driving significant changes to the portfolio of supply resources in New York. These conditions highlight the potential for future challenges to arise in meeting electric system demands under certain stressed conditions such as prolonged cold weather events and/or fuel supply or transportation availability constraints or disruptions.

In response, the NYISO engaged Analysis Group to assist in conducting a forward-looking assessment over three future winter periods to examine the fuel and energy security of the New York electric grid. Analysis Group was tasked with assessing winter fuel and energy security risks and identifying key factors that will affect the likelihood and potential severity of any risks.

The analysis was not designed to focus on the questions of economics or consumer costs, and does not involve the use of production cost modeling. Instead, the assessment is a deterministic, scenario-based winter reliability assessment.[6] It represents an evaluation of potential reliability risks and impacts under *severe* winter conditions and *adverse* circumstances regarding system resources, various potential disruptive conditions, and fuel availability. The objective is to better understand under what combinations of severe winter weather and adverse system conditions the reliability of the power system might be vulnerable, and what the potential impacts could be under such conditions.

2. Fuel and Energy Security Model

Analysis Group developed and applied its fuel and energy security model to comprehensively assess the risks of wintertime operation under adverse conditions, with specific application to the NYISO power system. The starting point for the analysis is expected system conditions for the upcoming winter season - the winter of 2023/2024. The analysis then considers two future winter periods - the 2026/2027 and 2030/2031 winter seasons. System demand, supply resources, and transfer capabilities are based on previously-vetted NYISO study assumptions,

[6] The deterministic analysis stack-orders the operation of generating unit and fuel types based on fuel availability and relative efficiencies, and compares available output to demand for each case analyzed. The model is described in full in [[Section III]].

including the most recently completed 2021-2040 System & Resource Outlook (2021-2040 Outlook).[7] The extended period of cold weather used in the assessment was based on analysis of 30 years of historical weather data. The cold weather period used spans seventeen consecutive days of frigid winter conditions, including a three-day severe cold weather event (occurring on days six through eight of the event).[8] The fuel and energy security analysis included the following data and modeling steps, conducted where appropriate for specific locations (load zones or combination of load zones) within New York (see Figure 12):[9]

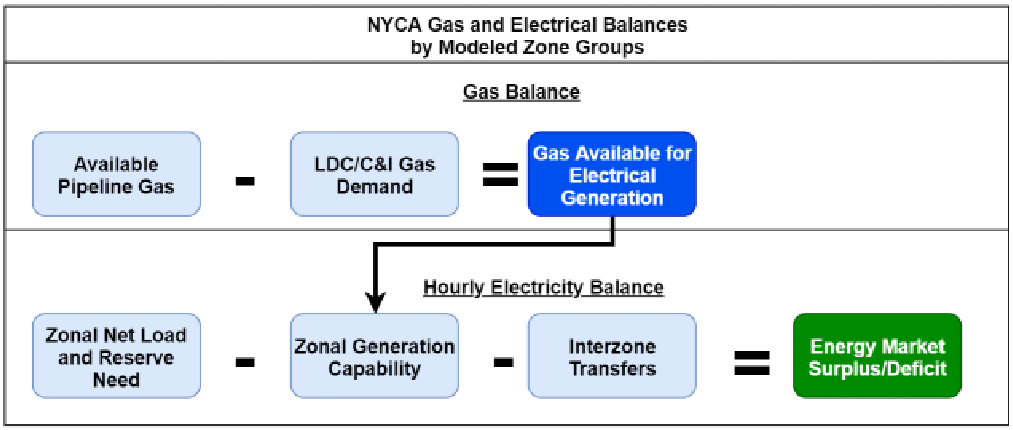
1. Weather: Identify severe winter conditions based on historical winter weather data, and use this to identify an appropriate extended "severe cold weather event" in terms of length, daily heating degree days, and including a short period of very severe weather within the duration of the extended event.
2. Electric and Gas Demand: Using historical data, establish locational relationships between temperature (heating degree days) and two factors affecting natural gas use and availability: (a) local gas distribution company (LDC) retail gas demand, and (b) electric load.
3. Fuel: Using current and historical fuel survey data reported by generation resources to the NYISO, evaluate the likely inventories and refill capabilities for oil-fired (including dual fuel) units.
4. Pipeline Capacity: Using public data from the U.S. Energy Information Administration (EIA), interstate pipelines, and other sources, estimate the capacity of natural gas infrastructure in New York to deliver natural gas for meeting both LDC retail gas demands and power system needs, net of what is known/forecasted to be committed to export to surrounding states/regions.
5. Natural Gas System Balance: Use items #2 and #4 above to determine a *natural gas system balance*, approximating the availability of non-firm natural gas for power generation on a daily basis over the extended severe cold weather period modeled.
6. Power System Resources: Combining estimates from item #5 and data on non-gas resource availability/production, identify the resources expected to be available for electricity generation under the modeled winter conditions, and stack order them based on likely output, availability of fuel, and operational efficiency, to determine total potential generation and transfers between locations in New York on an hourly basis over the modeled cold weather period.
7. NYISO Actions: Identify hours where actions to reduce energy-only exports to New England or activate wholesale demand response resources (specifically, Special Case Resources [SCRs] and/or the Emergency Demand Response Program [EDRP]) are necessary to meet load or maintain reserves, and model the effect of such actions.
8. Electric System Balance: Compare the hourly zonal demand for energy with the available electric generation (and inter-zonal transfer capability) to identify the *electrical supply/demand balance* on an hourly basis.

[7] New York Independent System Operator, "2021-2040 System and Resource Outlook (The Outlook)," September 22, 2022, available at https://www.nyiso.com/documents/20142/33384099/2021-2040-Outlook-Report.pdf.

[8] In effect, the modeled severe cold weather event represents a worst-case string of temperatures over a fourteen-day period and three-day cold snap, based on data over the past two and a half decades.

[9] Each component of the fuel security model and analysis, and the data and assumptions applied, are further described in more detail in [[Section III]] and the Appendices.

Figure ES-2: Gas and Electrical Balance Model



Using the aforementioned assumptions and model logic, the analysis evaluated a wide range of cases that vary along two dimensions: "scenarios" represent potential variations in the configuration of resources, fuel availability and power transfers, and "disruptions" (evaluated singularly or in combination) primarily identify episodic conditions that do not necessarily reflect permanent system changes. In total, the analysis assessed system performance across over two hundred "cases," each representing some combination of the identified scenarios and disruptions.[10]

The primary scenarios assessed are summarized in Table ES-1, with each scenario representing different combinations of (a) capacity imports from neighboring regions; (b) onsite oil inventory level for generation resources that can burn oil; and (c) timeframe for the development of new renewable resources.

Each scenario described above was also run against 11 disruptions, which involve various events or contingencies with respect to unit performance/availability, oil inventories, oil refill rates, and disruptions of natural gas delivery. The disruptions are summarized in Table ES-2.[11]

[10] The cases reviewed are described in more detail in [[Section IV]], and full case results are presented in detail in [[Appendix E]].

[11] Scenarios and disruptions are described in more detail in [[Section IV]].

Table ES-1: System Scenarios

	Imports	Oil	Infrastructure
Scenario Description	**IM All:** 1,200 MW capacity imports / minimum 300 MW capacity exports **IM Net0:** 300 MW capacity imports / minimum 300 MW capacity exports	**HFS:** Higher starting oil tank levels, 50% increase in starting storage levels	**REN:** Delayed construction of renewables as follows: *Winter 26/27:* 33% decrease of utility solar and land-based wind capacity from 2021-2040 Outlook "Contract Case" additions *Winter 30/31:* 20% decrease of utility solar, land-based wind, and offshore wind capacity 2021-2040 Outlook "Policy Case 1" additions
Scenario 1	IM All		
Scenario 2	IM Net0		
Scenario 3	IM All	HFS	
Scenario 4	IM Net0	HFS	
Scenario 5	IM All		REN
Scenario 6	IM Net0		REN
Scenario 7	IM All	HFS	REN
Scenario 8	IM Net0	HFS	REN

Table ES-2: Disruptions

Disruption Name	Description
1. Starting Conditions	No physical disruptions
2. High Outage	Double unit forced outage rate compared to historical averages
3. SENY Deactivation	Loss of significant capability (1,000 MW) in SENY (specifically, load zones G-I)
4. Nuclear Station Outage	Loss of major nuclear facility upstate (i.e., Nine Mile Point 1 and 2)
5. No Truck Refill	Unavailability of truck oil fuel delivery based on historical events such as snow storms
6. No Barge Refill	Unavailability of barge oil fuel delivery based on historical events such as NYC rivers freezing
7. No Refill	Unavailability of any oil fuel delivery due to severe fuel limitations affecting both barge and truck refueling
8. Non-Firm Gas Unavailable F-K	No non-firm gas-fired generation capability available in load zones F-K
9. Non-Firm Gas Unavailable NYCA	No non-firm gas-fired generation capability available anywhere in NYCA
10. Non-Firm Gas Unavailable 4 days	No non-firm gas-fired generation capability available anywhere in NYCA over the cold snap weekend, model days 6-9
11. Combination Disruption	50% firm gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2

3. Evaluation Method and Metrics

The purpose of the analysis was to identify any cases involving a potential loss of load event in any load zone, or where conditions triggered leading indicators of potential reliability challenges - that is, where conditions were tight enough to require operational steps to preserve system reliability (such as a reduction in energy-only exports, activating SCRs/EDRP, or reducing required reserves). Outputs of the various case runs were created to capture these conditions and quantify them in terms of (a) magnitude of a potential load deficiency (in megawatts (MW)), (b) duration of deficiency (in hours or days), and (c) frequency of the occurrence of deficiencies over the course of the modeled cold weather period.[12] Results for each case were synthesized in tabular and graphical forms to provide a comprehensive representation of the nature and magnitude of the fuel/energy security reliability risks (if any) under the range of system scenarios and disruptions analyzed.[13]

An additional step of the review involved an evaluation of the likelihood of case outcomes for the closest period studied, the upcoming winter 2023/2024 period.[14] This evaluation of likelihood was intended, in combination with the model's consequence analysis, to focus the review on a subset of cases that are both consequential and whose likelihood is at least on a par with system conditions and events that might typically be considered in system operational analyses. The final step of the analysis involved careful review of case outcomes, with a particular focus on cases that - based on the reliability impacts of the case identified by the modeling and the likelihood of

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[12] In addition to a complete representation of events or cases where there was a potential loss of load event, the metrics also quantify occurrences where the leading indicators are triggered (reduction in energy-only exports, activation of SCRs/EDRP, and/or violation of reserve requirements).

[13] A complete description of model output metrics and illustrative tables and charts is presented in [[Section V]].

[14] A full description of our evaluation is presented in [[Sections V and VI]].

realization - involved (a) potential conditions or system circumstances that could or should be evaluated in more detail, or (b) potential risks that warrant consideration of mitigating action.

C. Key Findings and Observations

1. The Changing Context for Fuel and Energy Security in New York State

Over the period studied, the New York power grid will undergo rapid and nearly continuous change as demand increases and shifts with electrification of the building and transportation sectors, the reliance on fossil fuels declines, the reliance on renewable and other clean energy resources grows, and major transmission capacity is added to the system. As with the 2019 FESA, the findings presented in this report continue to highlight the importance of continued evaluation of and monitoring, and preparedness for the possibility of fuel and generation resource unavailability during a prolonged period of cold winter weather. The results of these analyses demonstrate that the NYISO will need to rely significantly on dual-fuel (gas/oil) generation resources to support winter system reliability into the next decade, and should carefully and continuously monitor the evolution of supply and demand conditions and how these changes impact system operations during multi-day cold snap conditions.

Below is a summary of the assessment and key findings from the analysis based on existing resource expectations and conditions reflective of winter 2023/2024, as well as results for winters 2026/2027 and 2030/2031 based on projected generation resource mixture and electricity demand changes. In the context of fuel and energy security, the biggest challenge for New York State, the NYISO, and stakeholders over time will likely be in navigating the state's power system transition towards decarbonization in a way that does not jeopardize or compromise the resources, performance capability and infrastructure needed to support reliable winter operations.

The transition of the power grid - as evidenced by the requirements set forth in the CLCPA and other policies established by the state legislature and regulatory agencies - involves rapidly declining reliance on fossil fuels, and increasing reliance on weather-dependent renewables, energy storage, and other low-/no-carbon resources. Electricity demand is forecasted to substantially increase (and the timing of its use will change significantly) over the next two decades, with the expectation that electrification represents an efficient and least-cost path to decarbonization of transportation, building, and other sectors of New York's economy. Yet at the same time, the CLCPA requires that 70 percent of the state's electricity be provided by renewable generation by 2030, and 100 percent of the state's electricity be provided by zero-emitting generation by 2040.

The ongoing transition of the power system is an important consideration, particularly in light of the findings in this report (summarized below). This review is focused on a "snapshot" of future system conditions in the winters of 2023/2024, 2026/2027 and 2030/2031. Putting the analysis into the context of the continued evolution of the power system, one thing stands out: the availability and consistent contributions of adequate amounts of natural gas-fired and oil-fired (or dual fuel) generating resources is necessary to maintain power system reliability in cold winter conditions throughout the ongoing transition of the power system toward a zero-emission system. This is particularly true for meeting the energy needs of New York City. Simply put, avoidance of potential loss of load events in New York City, under plausible adverse winter conditions, requires operation of natural gas and oil-fired units during this transition. Reduction in the generation available from such resources - whether through, for example, low initial oil inventories, reduction in natural gas availability for power generation, or interruptions in the ability to refuel oil tanks throughout the winter- represents the most challenging circumstances for reliable winter system operations in New York over the coming years, as the transition envisioned by the CLCPA continues.

Major increases in renewable generation and other clean energy resources (such as energy storage) in these load zones – whether through offshore wind, additional transmission to accommodate incremental power flows from upstate renewables and other resources located outside these constrained regions, or both, can provide significant relief to and reduction in reliance on oil and natural gas for winter operations. The additional gigawatt-hours of intermittent generation from renewable resources – particularly offshore wind (injected into Long Island and New York City) – can potentially help to meet some portion of peak demands, and can help preserve oil and gas for continued operation over an extended cold weather event. Yet the timing for the integration of these resources in the system and to what degree they may be relied on under severe winter conditions is not well known at this time. It will be critically important over the next decade to fully understand and actively manage the impact of the evolving resource mix in New York.

2. Results

As described previously, the analysis begins with a supply and demand snapshot of the winters 2023/2024, 2026/2027 and 2030/2031 subject to severe winter conditions over the seventeen-day cold-weather modeling period. Over these winter periods, the system is depicted through various combinations of system scenarios and disruptions, representing over two hundred cases in aggregate. Each case is run through the fuel and energy security model, which generates a detailed set of case diagnostics.[15]

The key results for each case are depicted in Figure ES-3to Figure ES-5. These figures represent the occurrence of potential hourly loss of load events across the seventeen-day modeling period as a line chart within each case box, showing the relative magnitude, frequency, and duration of potential loss of load events for each case. No line within the box indicates no potential loss of load event associated with the case at issue. The most significant potential loss of load events are seen in cases involving disruptions to oil supply, gas supply, or combinations of disruption events.

For winter 2023/2024, the cases are also categorized with respect to magnitude and probability of impact.[16] Specifically, in Figure ES-6, cases are color coded based on their level of risk, taking into account both the severity of potential loss of load event impacts and an assessment of the likelihood of the conditions postulated in each case coming to fruition. With respect to the color coding, each case is categorized as follows:

- **White:** The case leads to few or no potential loss of load events, and none greater than 100 MW, and/or the probability of the combined scenario/disruption being realized is *extremely low, well outside* the types of system conditions and contingencies typically considered in operational assessments.
- **Yellow**: The case leads to potential loss of load events greater than 100 MW but none greater than 1,500 MW with such events generally being of moderate duration or frequency, and the probability of the combined scenario/disruption being realized is *low* or *on the order of* (or similar to) the types of system conditions and contingencies typically considered in operational assessments.[17]
- **Orange**: The case leads to potential loss of load events greater than 1,500 MW, but the probability of the combined scenario/disruption being realized is *low, likely less probable* than the types of system conditions and contingencies typically considered in operational assessments.

[15] The detailed results across all cases are further described in [[Section VI]], with the detailed diagnostics for each case presented in [[Appendix E]].

[16] See Section VI for a detailed description of the method for assessing case probabilities where applicable, and for the results for winter 2026/2027.

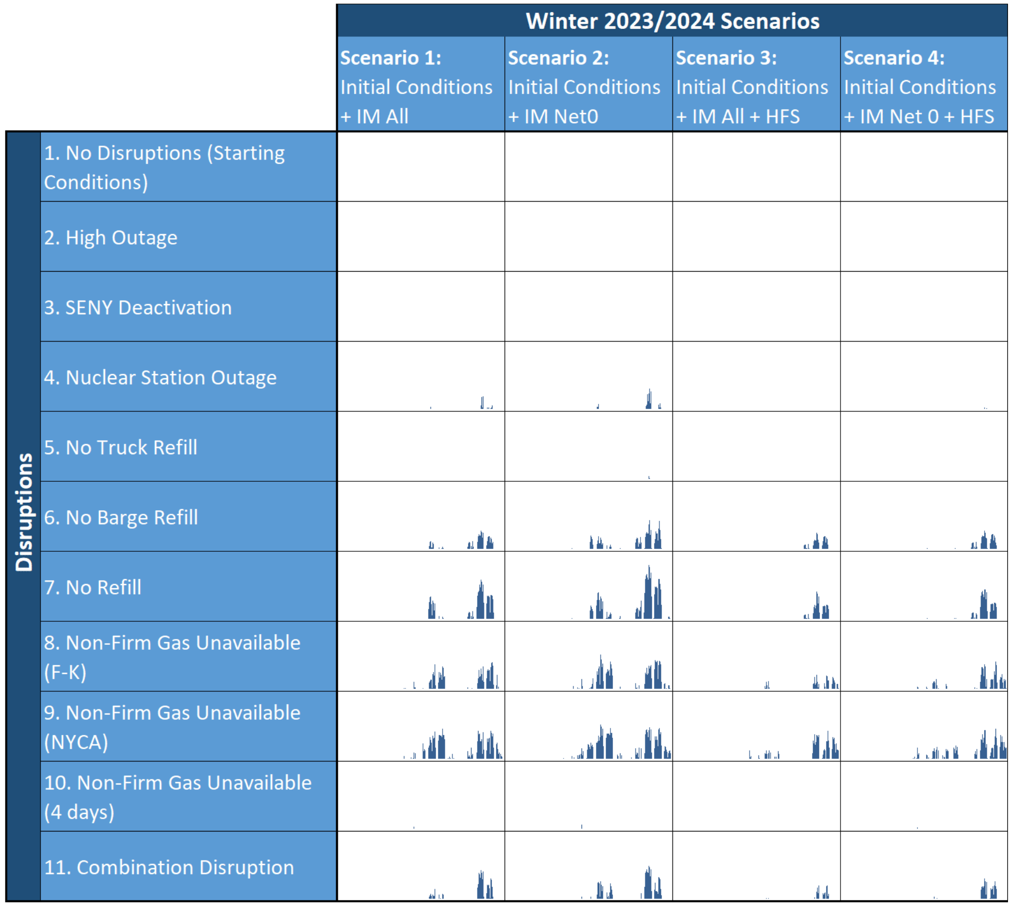
[17] The yellow color code has been updated relative to the 2019 FESA to reflect recent winter events that are now more probable under system conditions and contingencies akin to those typically considered in operational assessments and that could result in moderate loss of load events.

- **Red**: The case leads to potential loss of load events greater than 1,500 MW, and the probability of the combined scenario/disruption being realized is *on the order of* (or similar to) the types of system conditions and contingencies typically considered in operational assessments.

The purpose of combining assessments of both probability and consequence in this way is to focus in on a subset of cases that (a) have the potential for significant reliability risks, and (b) are probable enough to merit further attention and consideration of whether additional mitigating action is warranted (e.g., enhancements to operational procedures and/or market designs). While this process necessarily involves the application of professional judgment and the use of assumed metrics of impact, the transparent nature of the analysis and comprehensive set of diagnostics allows entities to develop their own interpretation of results, to the extent they differ from those contained herein.

It is useful to observe the results across modeled disruptions for a given scenario, and *vice versa*. In this way it is possible to see the specific impact of a given set of system conditions or disruptive event on reliability risks, or to gauge the magnitude of impact from one case to another, all else equal. For example, in all three winters modeled, scenario 1 contains a cross section of results that vary in probability and impact across the assumed disruptions. Figure ES-7 to Figure ES-9 show for each winter how both the severity of potential loss of load events (in MW, the y -axis) and duration across the 17-day cold weather event period (in hours, the x- axis) vary as the case steps from no disruptions through the various assumed disruption events. A full set of potential loss of load duration curves for each winter by both scenario and disruption are included in Appendix D.

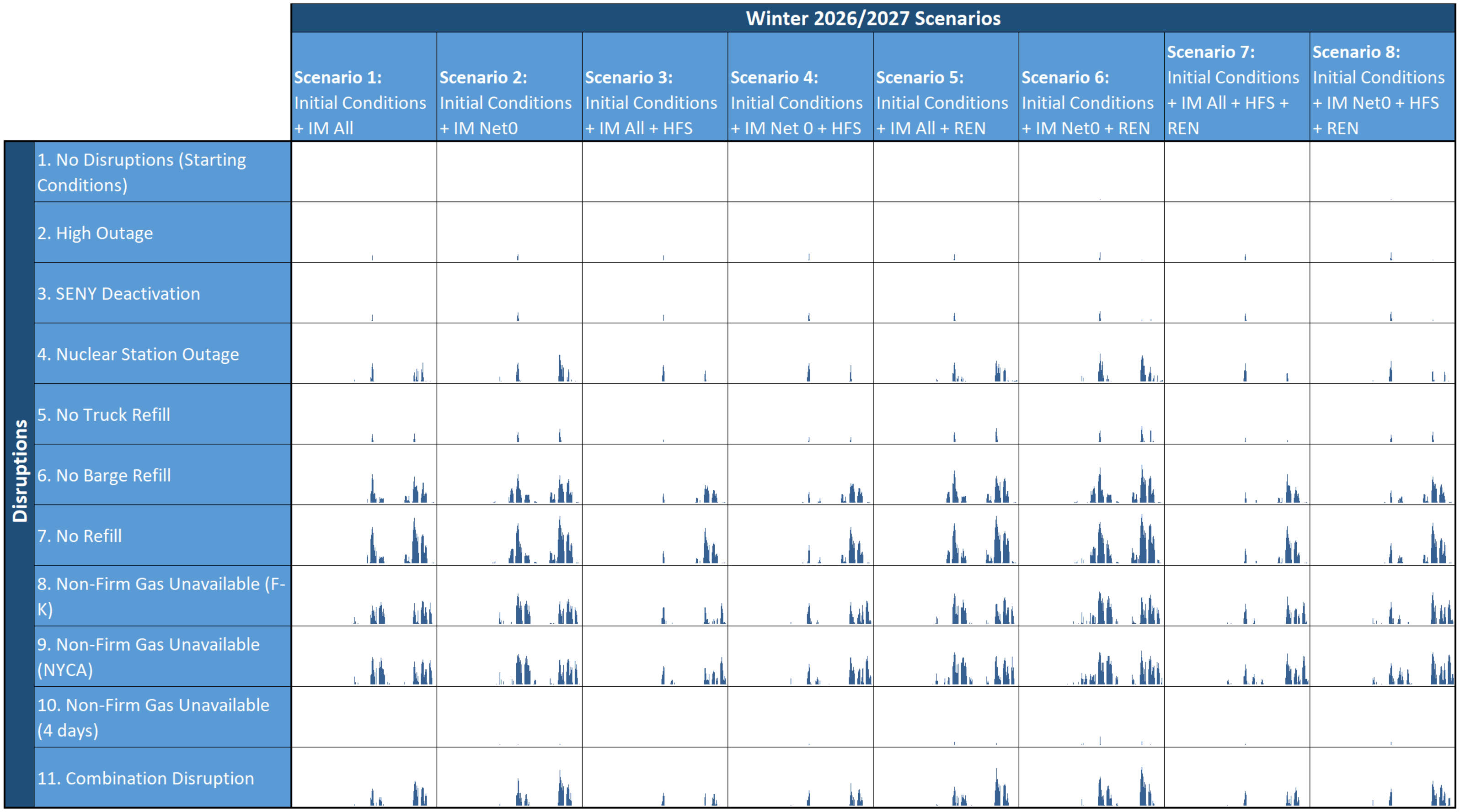
Figure ES-3: Potential Loss of Load Events by Case, Winter 2023/2024



Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

<u>**Scenario Key**</u>
IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

Figure ES-4: Potential Loss of Load Events by Case, Winter 2026/2027

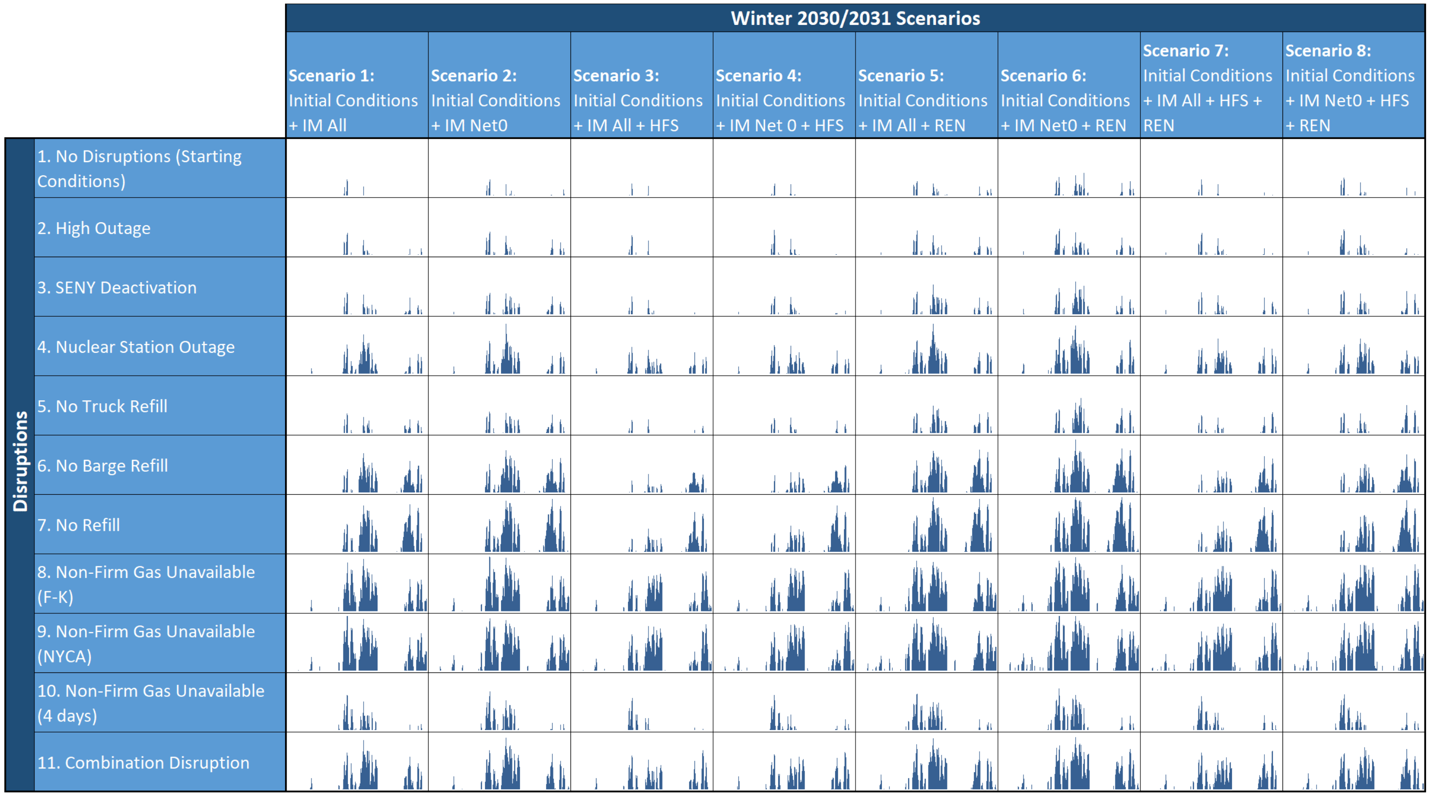


Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

Scenario Key

IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
REN = 33% decrease of utility solar and land-based wind capacity 2021-2040 Outlook Contract Case additions.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

Figure ES-5: Potential Loss of Load Events by Case, Winter 2030/2031[18]



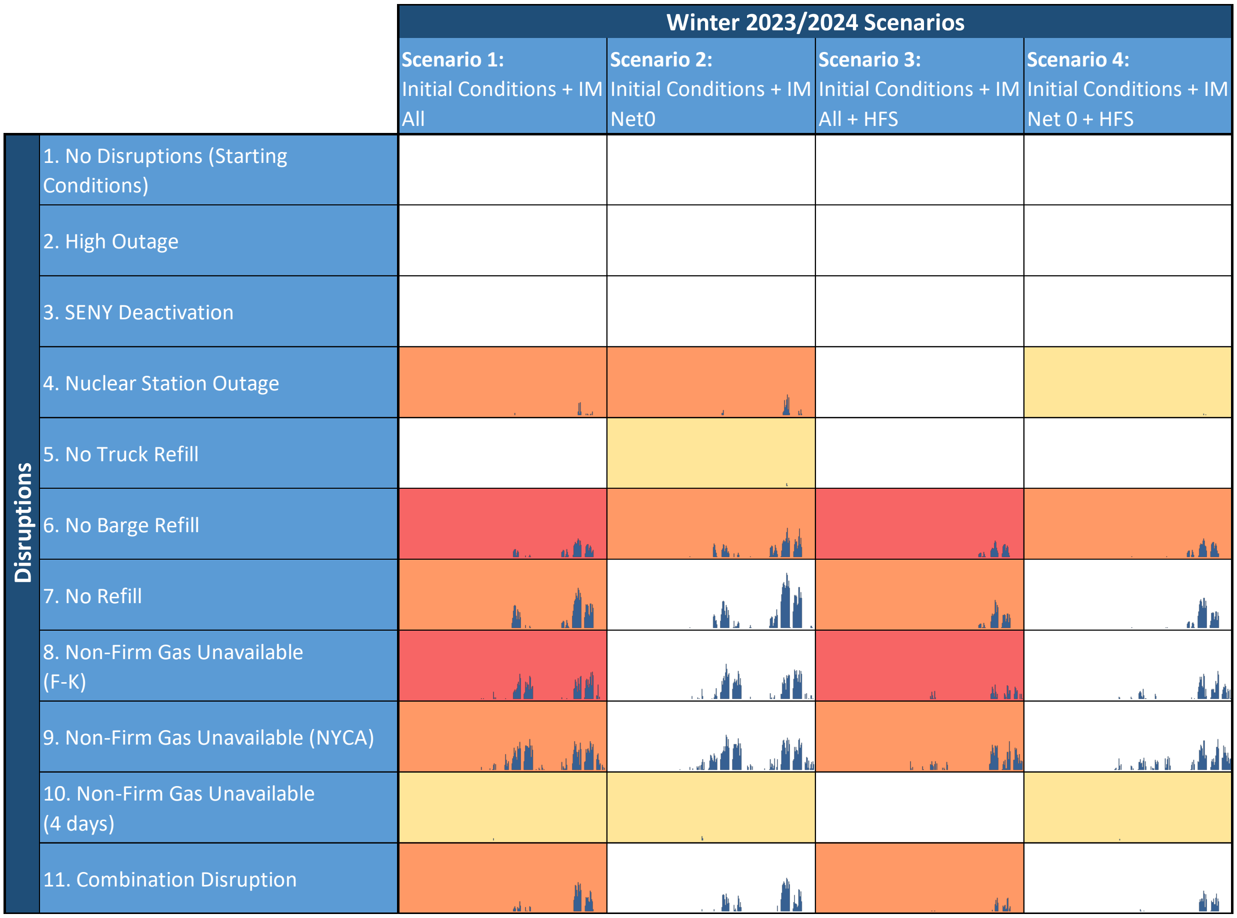
Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

Scenario Key

IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
REN = 20% decrease of utility solar, land-based wind, and offshore wind capacity 2021-2040 Outlook Policy Case 1 additions.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

[18] In the winter 2030/2031 only, there are instances where potential loss of load exceeds 10,000 MW in a given hour. The following five cases exhibit potential maximum hourly loss of load that exceeds 10,000 MW, falling between 10,000 MW to 11,500 MW: Scenario 1 – PD 9, Scenario 2 – PD 8, Scenario 5 – PD 7, Scenario 6 – PD 7, Scenario 6 – PD 9.

Figure ES-6: Heat Map of Potential Reliability Risks, Winter 2023/2024



Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

- Consequence 0-100 MW or probability extremely low (far outside normal operational assessments)
- Consequence 100 - 1,500 MW, of moderate duration/frequency, and probability low or on the order of normal operational assessments
- Consequence greater than 1,500 MW, and probability low (meaningfully less likely than normal operational assessments)
- Consequence greater than 1,500 MW, and probability on the order of normal operational assessments

Scenario Key

IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

Figure ES-7: Loss of Load Duration Curves for Scenario 1, All Disruptions, Winter 2023/2024

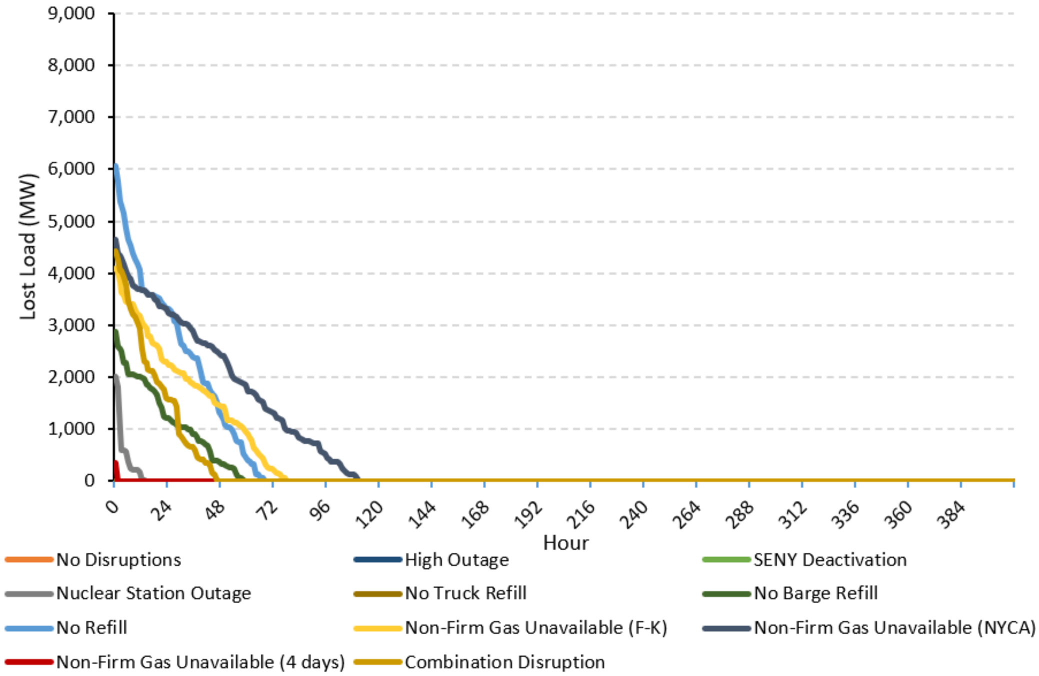


Figure ES-8: Loss of Load Duration Curves for Scenario 1, All Disruptions, Winter 2026/2027

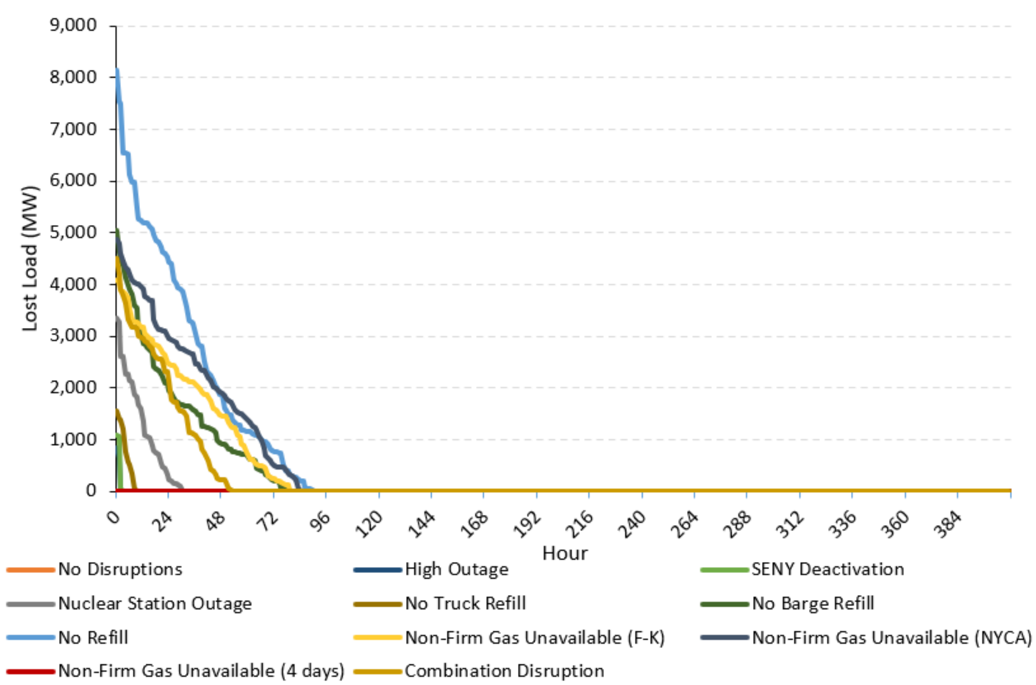
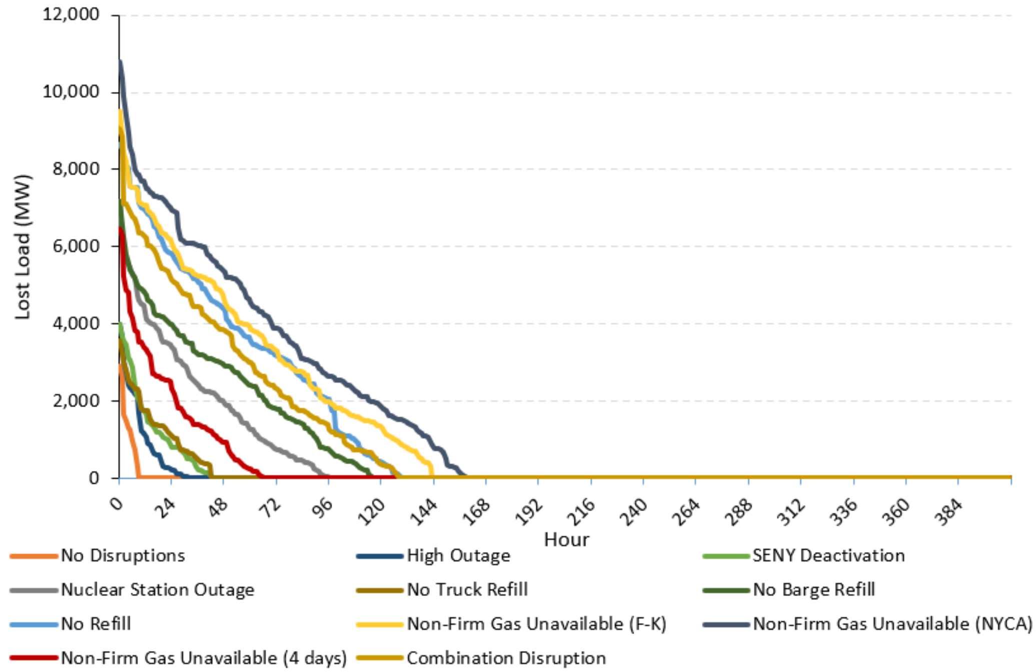


Figure ES-9: Loss of Load Duration Curves for Scenario 1, All Disruptions, Winter 2030/2031



3. Observations

Based upon the review of detailed case diagnostics, the following observations with respect to fuel and energy security in New York have been identified:

The modeling results show the potential for operational challenges and loss of load events across all three winters studied. The frequency and severity of projected potential loss of load events grow over the modeling time horizon. For the upcoming winter 2023/2024 period, fuel supply disruptions are the most prominent concern. In the future two winters modeled (i.e., 2026/2027 and 2030/2031), as the system resource mixture evolves, lulls in production from intermittent generation resources (particularly offshore wind) also become an important consideration. Finally, in 2030/2031 winter period, in which modeling input assumptions are subject to the greatest uncertainty, the results portend a growing frequency in operational challenges and potential for loss of load events across all assumed disruptions.

The availability of oil and gas generation resources is critical to alleviate potential loss of load events. The overall risk associated with disruptions to fuel and energy availability during winter months grows as the resource mixture changes and electricity demand increases to meet the state's decarbonization objectives. For the upcoming winter 2023/2024 period, the cases reviewed that *do not* involve significantly adverse assumptions about system configurations or major disruptive events exhibit little or no risk to power system reliability. However, in the winter 2026/2027 period, the overall risk associated with less adverse disruptions rises. The winter 2030/2031 modeling results reinforce the results observed in the winter 2023/2024 and 2026/2027 analyses. The potential for loss of load events substantially increase for the winter 2030/2031 period, including in those instances with no assumed disruptions. The results underscore the scope of the NYISO's operational challenges that can result when fuel and energy supplies are disrupted/limited during the ongoing transition of the power system in response to the requirements of the CLCPA.

In comparison with the 2019 FESA, the results show that the NYISO power system has grown more sensitive to fuel disruptions in recent years. In particular, the following updated model inputs (relative to the 2019 FESA) drive the increase in the potential for system reliability risks: (1) the estimated gas available for electricity generation is reduced based on updated data and information from New York's LDCs; (2) fewer renewable and other clean energy resources have come online relative to the projections in 2019; (3) fossil unit retirements (especially peaking facilities downstate) proceeded at the fastest pace assumed in the 2019 FESA, and are included in all modelling scenarios; (4) certain generators have reported increased oil refill lead times and/or lower oil inventories to start the winter in the NYISO fuel surveys; and (5) energy imports from ISO-NE to Long Island are assumed in all cases. Collectively, the initial conditions for this updated study more closely resemble scenarios in the 2019 FESA that had more potential for loss of load events.

Higher starting oil tank inventory levels help alleviate operational challenges and potential loss of load events. As the generation mixture evolves and electricity demand increases during the ongoing transition to a decarbonized electric grid, the importance of ensuring that generation resources have sufficient oil storage during a multi-day cold weather period grows during the ongoing transition of the grid toward decarbonization. The results of the analyses show that higher starting oil inventory levels and timely oil tank replenishment reduce or eliminate potential loss of load events. For example, an assumed 50% increase in starting oil inventory levels resulted in an average decrease in modeled loss of load MWh of 58% for winter 2023/2024 cases, all else equal. Consideration of a 96-hour oil inventory, as is being evaluated and discussed in certain ongoing market design initiatives, is appropriate, as such a requirement could help ensure better preparedness for cold weather events.

Ensuring oil inventories that allow for even longer than 96-hour operations would provide even greater fuel security during prolonged cold weather.

Significant interruptions in the availability of natural gas for power generation can introduce challenges for reliable operations. Disruptions involving the loss of (or reductions in) non-firm natural gas for power generation NYCA wide, or only in load zones F-K, lead to potential loss of load events under all scenarios.

Recent winter weather events reinforce the importance of ensuring that New York's power system will be able to operate reliably during extreme winter weather. The impacts of recent events, such as Winter Storms Uri and Elliott, revealed unexpected operational challenges for system operators. Large numbers of electric generation resources could not be operated because of both equipment failures and inability to obtain fuel supply. The presence of potential loss of load events in the modeling results show that severe winter weather conditions could have a similar effect in New York. Moreover, operational challenges in other regions during severe winter weather conditions could lead to decreased electric imports into New York, which the modeling results indicate would exacerbate the potential for loss of load events.

Significant potential for loss of load events appear in cases involving reduced operation of oil-fired generating assets, particularly in New York City. New York encounters meaningful reliability challenges when little natural gas is available and/or the ability to rely on stored fuel for energy (e.g. replenish oil supplies) is constrained by weather or other factors. In fact, the vast majority of potential loss of load events occur in cases subject to disruptions associated with lower initial fuel oil inventories at oil and dual fuel power plants (i.e., consistent with recent observations), and/or reductions in or elimination of oil refill capability. In these cases, potential loss of load events tend to arise later in the seventeen-day modeling period as inventories are used up and are unable to be replenished.

Dual fuel capability – with oil as a backup fuel to natural gas – is vital for maintaining reliability during the ongoing system transition. Taking into consideration the demand for natural gas by LDCs for serving retail needs, there simply is not enough gas available for power generation downstate under prolonged, severe cold winter conditions to ensure reliable operations, absent the ability of dual-fuel units to operate on alternative fuel options. While these resources may operate economically – and to the advantage of electricity consumers – most of the year on available non-firm supplies of natural gas, under severe cold weather conditions LDC retail gas demand and other firm natural gas transportation commitments (including for deliveries to neighboring regions) reduce available natural gas for power generation to levels below that needed for reliable system operations. Maintaining adequate firm fuel resources such as firm gas only units, dual fuel and other oil-fired operating capability is critical to reliable operations during adverse winter conditions, especially in the downstate region, during the ongoing transition of the power system.

A number of circumstances leading to potential loss of load events are observed for New York City. Many cases with potential loss of load events greater than 1,500 MW and probability of occurrence conceptually similar to normal operational assessments were observed in New York City. New York City's vulnerability stems primarily from a particular reliance on oil-fired capacity, energy transfers from upstate, and a growing reliance on offshore wind generation resources whose energy production can be significantly reduced for long periods of time ("wind lulls"). Maintaining dual fuel (and other oil-fired) operating capability throughout the ongoing transition toward a decarbonized grid, ensuring available imports from upstate, and accounting for offshore wind energy production intermittency, are critically important to reliable winter operations for New York City.

Upstate generation resource availability is critical to provide energy to New York City. Generation resource unavailability in southeastern New York and/or an extended nuclear station outage result in increased potential loss of load events. The NYISO's reliance on the availability of its existing generation resource mixture upstate – and the transmission to deliver it downstate – grows along with projected electricity demand growth in response to system changes in response to requirements of the CLCPA.

The NYISO continues to take many steps to address potential risks associated with fuel and energy security concerns. The NYISO monitors, evaluates, and prepares to address potential risks associated with the availability of fuel and performance of generating assets. This includes a variety of practices and requirements intended to ensure continuous monitoring of assets and fuel inventories, and visibility into the operations, capacities and constraints of interstate pipelines and local natural gas LDC systems; the relative coordination of the timing of natural gas and electricity markets and the ability of generators to account for fuel opportunity costs in offers; the existence of requirements on certain downstate generators related to the capacity to operate on multiple fuels and switching fuels if and as needed based on prevailing temperature conditions; the incorporation of dual-fuel requirements for peaking plant technologies in the setting of the ICAP Demand Curves for downstate capacity regions (load zones G-K); and the establishment of reserve requirements statewide and downstate to reflect locational reserve needs. The set of steps already taken through changes in market rules and/or operating procedures have the effect of both increasing situational awareness of the risks and instituting requirements and incentives supporting the availability of fuel and the operation of assets important for reliable winter operations.

The state's renewable and clean energy resources can provide valuable reliability support. While the potential reliability challenges associated with wind lulls are significant and increase as the state's dependence on weather-dependent resources (especially offshore wind in the downstate region) increases, these resources can also support reliable operations over the modeled winter period by reducing the drawdown of oil inventories. The injection of a large quantity of offshore wind energy directly into New York City and Long Island at times throughout the modeled seventeen day cold weather event helps preserve limited oil and natural gas for supporting reliable operations later in the modeled severe cold weather period. Similarly, a review of certain cases with limited magnitude and duration of potential loss of load events could be eliminated through the operation of additional energy storage capacity in targeted locations.

Over the longer term, the projected magnitude and pace of change to the resource fleet stemming from requirements under the CLCPA grows in importance. The fundamental changes envisioned by the CLCPA suggest that the power system will play a critical role in decarbonization of the state's economy, with at least two fundamental shifts that will affect fuel and energy security during winter months. The first involves the potential electrification of transportation, heating and other sectors to achieve the required GHG reductions in those sectors at the lowest possible cost to consumers. This is projected to significantly increase and change the demand for electricity within New York State, and particularly in the downstate load centers that the analysis demonstrates may be most susceptible to winter energy security risks. The second is the contemporaneous decarbonization of the electric sector itself – requiring that 70 percent of all electricity be met through renewable generation within roughly ten years (by 2030), and that all electricity be provided by zero emissions resources within approximately twenty years (by 2040).

The potential for rapidly expanding demand for electricity combined with dramatic reductions in fossil-fired generation – including presumably the oil- and gas-fired generation that is currently critical for winter system reliability in the downstate region – warrants careful consideration around how to manage this transition from the perspective of reliable winter operations.

The results of this fuel and energy security assessment reinforce the importance of the NYISO's continued evaluation, monitoring, and preparedness for the possibility of fuel and generation resource unavailability over

a prolonged period of cold winter weather. The NYISO's ongoing assessments of fuel and energy security risk are critical to plan and prepare for system operations during prolonged cold weather events. The purpose of this report is not to point to a specific set of recommended actions based on the fuel and energy security analysis described in this report. However, the results of the modeling analyses demonstrate the critical importance of continued and careful monitoring of the evolution of supply and demand conditions and how these changes may complicate system operations during multi-day cold snap conditions. Moreover, with the potential for growing electricity demand in the state, in part due to electrification of the vehicle and building sectors, there will be increased importance in planning to reduce the risk of potential disruptions in fuel and energy supply.

4. Options

There is a wide range of potential options to consider that flow from the results of the analysis and the key conditions driving circumstances that lead to potential loss of load events, the experience with winter fuel and energy security efforts in other regions (*e.g.*, ISO-NE and PJM), and the specific circumstances in New York. Potential options include:

Continued monitoring and analysis. The impact of severe winter conditions on power system operations in New York is highly dependent not only on the availability of fuel for generating resources, but on the portfolio of resources available, transmission capability to accommodate transfers throughout the state, the level and shape of demand under winter peaks, and the various disruptions or contingencies that may occur during cold weather conditions. Continued monitoring of these conditions represents a clearly valuable endeavor for reliable system operations. The NYISO and its stakeholders should ensure that system and resource planning efforts continue to account for the possibility of disruptive events on both the electric and gas systems and the possibility of winter fuel and energy security-related reliability challenges. For example, the reliance in New York on the flexibility afforded by dual fuel capability, particularly downstate, suggests continued or expanded vigilance in monitoring the practices of generating asset owners with respect to establishing initial winter fuel oil inventories and executing pre-season or in-season contracts with fuel oil suppliers for the reliable delivery (by barge and/or truck) of replenishment fuel on regular and as-needed bases. Moreover, a key uncertainty in the analysis is the actual expected availability of natural gas to support power generation under severe cold weather conditions. The NYISO should continue to interact with generation operators, interstate pipeline operators and the state's natural gas LDCs, and conduct analysis based on available data, to maintain an up-to-date understanding of the changing circumstances of natural gas infrastructure, LDC demand, and likely contractual flows out to neighboring regions.

Assessment of the adequacy of incentives for appropriate pre-season fuel oil inventory levels and/or replenishment arrangements. The current operational capability of oil-fired capacity downstate is critical to winter power system reliability in New York. The NYISO already monitors inventories, use and replenishment for these units. Moreover, certain units in the downstate region are subject to mandatory oil-burn operations under specified temperature and/or gas system conditions. Nevertheless, given oil's importance to supporting reliable operations during the ongoing transition of the grid toward a carbon free system, if the continued monitoring of fuel availability identifies reductions in inventory levels and/or delays in replenishment in the future that may pose reliability risks to winter operations, the NYISO and its stakeholders may want to evaluate the adequacy of current incentives for establishing appropriate pre-season inventory levels and replenishment contracting arrangements. Appropriate signals for asset owners to have sufficient fuel to support continued operations throughout an extended period of cold-weather conditions are important for managing reliability risks.

Review of the potential for geographically-targeted development of new renewable and energy storage resources associated with implementation of the CLCPA. There is little doubt that there will be a major expansion of advanced low and no carbon energy technologies over the coming decades. To the extent that winter fuel and energy security risks tend to be concentrated in downstate load zones, the NYISO may consider evaluating how the interconnection or installation of new renewable and energy storage resources in specific load zones or locations on the bulk power system could provide ancillary winter reliability benefits. For example, an assessment of the magnitude, frequency and duration of potential loss of load events in specific locations/regions, and under plausible system conditions, could identify particular value associated with energy storage resources that meet certain technical specifications (size, discharge rate, and duration) that could mitigate or eliminate identified reliability risks. In a similar vein, to the extent the CLCPA warrants further expansion of transmission system infrastructure, the NYISO could consider how to best plan for and design transmission expansion in a way that mitigates potential fuel security issues.

Ongoing proactive scenario analysis of the potential impacts of the CLCPA. As noted previously, the state of New York is embarking on a period of unprecedented change in many of the critical demand and supply realities in the state; this suggests value in continuing to proactively engage in reliability-focused scenario assessment of New York's ongoing implementation of CLCPA directives, reviewing (a) potential changes in the magnitude and shape of power demand across all seasons under postulated scenarios of electrification of transportation and heating sectors; (b) the likely quantities, technical parameters, and interconnection locations of specific grid-connected and distributed renewable and energy storage resources through 2030; (c) the shape (or hourly generation profile) and effective load carrying capability of grid-connected and distributed solar, onshore wind, offshore wind resources, and energy storage resources; and (d) the impact of changing demand and supply profiles on the resources and operating capabilities needed to maintain power system reliability.

Continuous updating and refinement of fuel and energy security modeling. The results demonstrate that the flexibility afforded by dual fuel capability, particularly downstate, is of critical importance to reliable winter operations throughout the ongoing transformation of the power sector envisioned by the CLCPA. The importance of this capability is expected to persist throughout the ongoing transition of the New York's resource fleet toward a decarbonized grid. The results of the analysis also highlight the potentially significant impacts of timely development of new renewable, energy storage, and other clean energy resources. In light of the ongoing transition of the resource fleet, the NYISO should consider continuing the development, refinement, and application of the fuel and energy security model as a tool for continued assessment of winter operational risks as the system and circumstances change over time. For example, the NYISO should consider periodic refreshing of the analysis herein (or certain key aspects thereof) to account for changes in system conditions over time. The NYISO should also consider using the results of this analysis and the capability provided by the fuel and energy security model to identify certain key metrics that could serve as leading indicators of potential future reliability and/or fuel security concerns (e.g., identifying the magnitude of dual fuel capability that may become unavailable and/or resources such as DEFRs that may be necessary to mitigate adverse impacts to reliable winter operations arise). Such indicators could be used as part of ongoing, proactive monitoring to identify changes in system conditions that would trigger a need for engaging with stakeholders to assess whether further mitigating action is warranted, and, if so, identifying and evaluating potential remedial options.

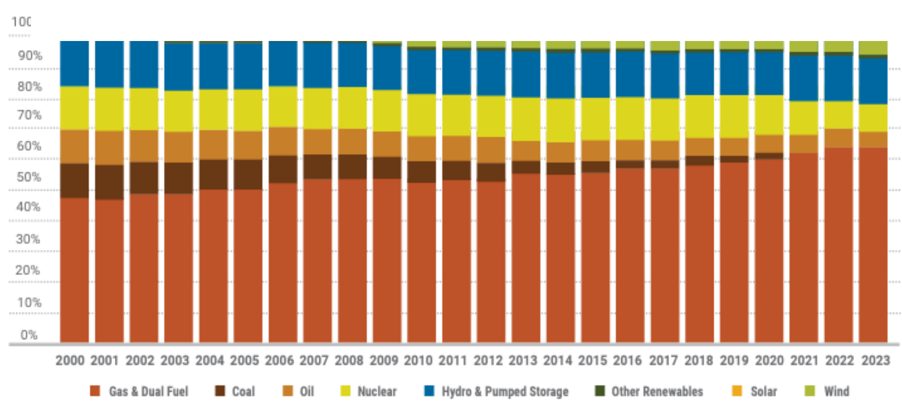
II. Introduction and Purpose

A. Overview

The NYISO is responsible for the reliable planning and operation of the state's bulk power system and the design and administration of the state's competitive wholesale markets. For more than twenty years, the NYISO has overseen constant improvements in system reliability and efficiency, power market competitiveness, and consumer costs, while addressing - from both planning and operational perspectives - continuous changes in the infrastructure, fuels, and policies that drive evolution of the power grid. Two key factors have dominated this evolution in recent years, a trend that is likely to amplify and accelerate in years to come. The first is the emergence of natural gas - with the arrival of shale gas - as the fuel of choice for new generating infrastructure development; the second is the march towards decarbonization of the state's economy driven by state policy and, in part, by the economics of certain renewable resource options.

These changes have significantly altered and affected the state's generation fleet, and have driven the state to greater dependence on natural gas and renewable resources for power system operations. As seen in Figure 1, since 2000, reliance on gas fired or dual-fuel units with gas as their primary fuel, and renewable resources (wind and solar) has increased significantly.[19] In terms of annual generating capability, since 2000, the contribution of production capability from units with natural gas as the primary fuel has increased from 47 percent to over 60 percent (Figure 1).

Figure 1: New York State Fuel Mix Trends: Capacity 2000-2023



Over this period the increased use of natural gas in New York has contributed to meaningful consumer and public health benefits, as both the price of electricity and the emissions associated with power system operations have generally declined.[20] Achievement of these benefits have been driven mostly by the displacement of older, less efficient and more polluting fossil fueled generation with newer, more efficient and less polluting natural gas-fired generation and renewable resources. Generating resource diversity of all types - in fuel source, mode of operation, geography, size, etc. - can contribute to the resilience and reliability of the power system. It is thus important to continually review a system's mix of generating resources and consider whether the collective attributes of the bulk power system introduce or mitigate reliability risks. The increased dependence on natural gas and weather-dependent renewables does not *necessarily* increase the challenges associated with reliable system operations, and does not by definition increase the risks associated with maintaining system reliability in the winter. Nevertheless, in light of the current circumstances and context - involving increased use of natural gas and a potentially rapidly-evolving power system that to-date has been strongly dependent on fossil-fired

[19] NYISO Power Trends 2023, p. 39.

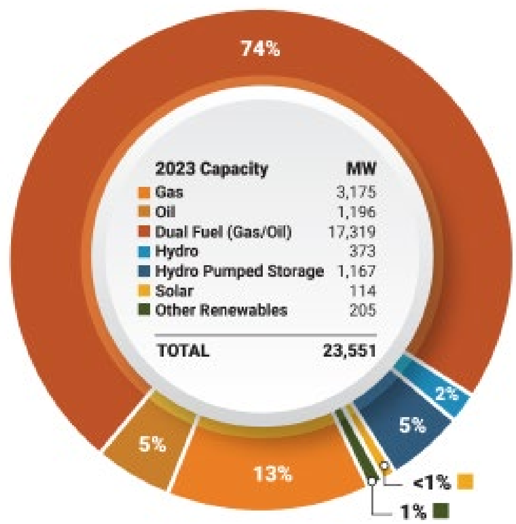
[20] NYISO Power Trends 2019, p. 33.

generation (particularly in the downstate region – see Figure 2)[21] – the NYISO engaged Analysis Group to update and expand its 2019 fuel and energy security risk assessment during winter operating conditions.[22] This 2023 analysis evaluates the NYISO's system projected supply/demand balance for three future winters—2023/2024, 2026/2027 and 2030/2031— under conditions that include a seventeen-day period of extended cold weather, including an extreme cold snap during three of those days.

Several factors suggest that increased monitoring and analysis of the impact of increasing dependence on natural gas and weather-dependent renewables on the reliable operation of the NYISO power grid are warranted:

- Increased dependence on any fuel generally has the potential to decrease the diversity of power system infrastructure, and reduce the reliability benefits that flow from greater diversity (in the fuel source, location, size, and operational modes of power system generating resources).
- The growth in use of natural gas and weather-dependent renewables has coincided with the retirement of generating capacity operating on other fuels, and the potential continued retirement of fossil-fired generation resources.
- The state's continued efforts to reduce emissions of harmful pollutants and decarbonize all sectors of the economy - most recently through the enactment of the CLCPA - have potentially two significant outcomes: (1) a continued decline in oil-fired and other fossil-fired generation that is currently critical for reliable winter system operations downstate, and (2) a potentially significant increase in (and change in the shape of) demand for electricity, due to potential electrification of the building, transportation, and other sectors in the economy. This electrification is needed to meet the CLCPA's economy-wide GHG reduction requirements. Despite the need to reduce fossil fuel combustion across all sectors to meet the state's GHG emission reduction targets, fossil-fired generation (including natural gas) will be needed for reliable power system operations throughout this transition, to support electrification of other sectors (and associated increases in electricity demand), and help manage the greater variability of increasing quantities of weather-dependent renewable generating resources.

Figure 2: Downstate Generating Capacity, Zones F-K



New York is not alone in facing these challenges or in assessing the risks to system operations associated with a changing resource mix, increased reliance on natural gas and renewable resources, and policies aimed at accelerating and amplifying the deployment of renewable and other clean energy resources. In the face of the recent extreme weather events in the U.S. (specifically, the January 2018 cold weather event, January 2021 Winter Storm Uri, and December 2022 Winter Storm Elliott), NERC and FERC have issued reports on each of these events chronicling the challenges faced by the electric grid, and laying out recommendations to mitigate the negative

[21] NYISO Power Trends 2023, p. 37.

[22] Analysis Group 2019 FESA.

impact of cold weather events on the grid in the future.[23] Following these reports, NERC has been releasing corresponding updates to NERC Reliability Standards, NERC Alerts, and NERC Reliability Guidelines, all aimed at mitigating winter bulk electric system reliability risk. Additionally, the NYISO's neighboring U.S. markets - ISO-NE and PJM - are also continually examining the issue of winter fuel security. Both regions released fuel security studies in 2018.[24] Since the 2018 report, PJM has continued monitoring winter grid reliability in the face of extreme events. After Winter Storm Elliott, PJM conducted a study on the challenges the grid faced during that event,[25] and the recommendations from that study are being acted upon through PJM's stakeholder process to reduce future reliability risk during extreme cold weather events.[26] In February 2022, ISO-NE started a probabilistic extreme weather events analysis with Electric Power Research Institute (EPRI) that is currently in progress.[27] Collectively, these reports and actions indicate the importance of studying the risks of extreme cold weather to the electric grid to help mitigate winter operational challenges. Summaries of relevant NERC and FERC reports and actions, as well as ISO-NE's and PJM's winter reliability work are described in Appendix A.

The state of New York has witnessed significant changes over the last decade and a half, driven primarily by the emergence of natural gas as the fuel of choice for electricity generation. Going forward, the state is embarking on an ambitious and challenging period of transition - one that may require an unprecedented level and pace of change in power system infrastructure and operations to achieve the CLCPA-mandated GHG emissions reductions in all sectors of the economy. In this context, it is important for the NYISO, electricity market participants, and stakeholders to consider the current risks - if any - associated with winter system operations in New York, and to again explore the key factors that will likely drive how these risks may change over time.

B. Purpose of the Study

The mix of fuels used to generate electricity affects both the reliability and resilience of the bulk electric system. A balanced array of resources enables the system to better address issues such as price volatility, fuel availability and stressed/abnormal operating conditions. New York's electric generation fleet has historically been comprised of a relatively diverse mix of fuel types.

The decline in natural gas prices, technological advancements, environmental and economic considerations, and public policies are driving significant changes to the portfolio of supply resources in New York. These conditions highlight the need for assessing the potential for future challenges to arise in meeting electric system demands

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[23] FERC and NERC Staff Report, "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018," July 2019 (hereafter, "FERC NERC January 2018 Cold Weather Report"), available at https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf; FERC - NERC Regional Entity Staff Report, "The February 2021 Cold Weather Outages in Texas and the South Central United States," November, 2021 (hereafter, "FERC NERC February 2021 Cold Weather Event Report"), available at https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and; NERC and FERC, December 2022 Winter Storm Elliott Inquiry into Bulk Power System Operations; FERC, NERC and Regional Entity Joint Team; Status Update, June 15, 2023 (hereafter, "NERC/FERC Winter Storm Elliott Inquiry Update"), available at https://www.ferc.gov/news-events/news/presentation-december-2022-winter-storm-elliott-inquiry-bulk-power-system.

[24] ISO-NE, "Operational Fuel-Security Analysis," January 17, 2018 (hereafter, "ISO-NE Operational Fuel-Security Analysis"), available at https://www.iso-ne.com/committees/key-projects/implemented/operational-fuel-security-analysis; PJM, "Fuel Security Analysis: A PJM Resilience Initiative," December 17, 2018 (hereafter, "PJM Resilience Initiative"), available at https://www.pjm.com/-/media/library/reports-notices/fuel-security/2018-fuel-security-analysis.ashx.

[25] PJM, "Winter Storm Elliott Event Analysis and Recommendation Report," July 17, 2023 (hereafter "PJM Winter Storm Elliott Report 2023"), available at https://www.pjm.com/markets-and-operations/winter-storm-elliott.

[26] PJM Winter Storm Elliott Report 2023, p. 125.

[27] ISO-NE, "Operational Impacts of Extreme Weather Events Key Project," available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events/.

under certain stressed conditions such as prolonged cold weather events and/or fuel supply or transportation availability constraints or disruptions.

In response, the NYISO engaged Analysis Group to conduct a forward-looking assessment of the potential risks to New York associated with wintertime power system operations in three future winters: 2023/2024, 2026/2027, and 2030/2031. Analysis Group was tasked with assessing winter fuel and energy security risks, and identifying key factors that will affect the likelihood and potential severity of any identified risks.

The analysis was not designed to focus on the questions of economics or consumer costs, and does not involve the use of production cost or economic modeling. Instead, this is a deterministic scenario-based winter reliability assessment. It presents an evaluation of potential reliability risks and impacts under *severe* winter conditions and *adverse* circumstances regarding system resources, disruptions, and fuel availability. The objective is to better understand under what combinations of severe winter weather and system conditions may adversely impact power system reliability, and what the potential impacts could be under such conditions.

While the model described herein is rooted in historical circumstances and current demand and resource expectations, where possible the report seeks to have an eye towards the unprecedented changes underway in New York. New York's expectations for the future transition of the power grid - as evidenced by requirements set forth in the CLCPA and many other policies established by the state legislature and regulatory agencies in recent years - involves rapidly declining reliance on fossil fuels, and increasing reliance on renewables, other low-/no-carbon resources, and energy storage. Demand for electricity may substantially increase (and potentially significantly change in shape) over the next two decades, assuming electrification represents an efficient and least-cost path to decarbonization of transportation, building, and other sectors of New York's economy. Yet at the same time, the CLCPA requires in the electric sector achievement of 70 percent renewable generation by 2030, and 100 percent zero-emission generation by 2040.

C. Overview of Analytic Method

Analysis Group developed and applied its fuel and energy security model to comprehensively assess the risks of wintertime operation under adverse conditions, with specific application to the NYISO power system. Figure 3 presents at a high level the analytic components of the fuel and energy security model, used to generate results for all cases. As the schematic shows, there are two major elements of the analysis. First, historical data are used to model a balance of the natural gas system in New York, in order to determine the availability of natural gas to support electricity generation at natural gas-fired power plants. With this data, the model then undertakes a structured, locational balance of supply and demand on the electric system on an hour-by-hour basis over the seventeen-day modeling period.

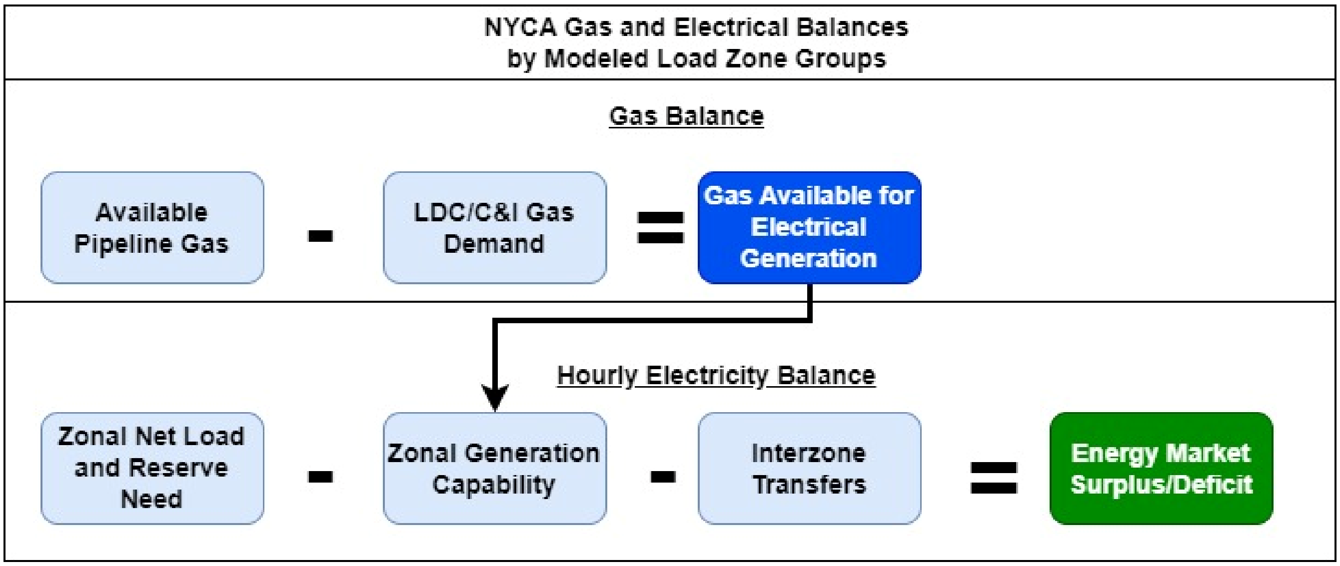
The end result of this modeling effort is a set of detailed diagnostics for each case, describing potential loss of load events (if any) in terms of magnitude (MW of potential deficiency), frequency, and duration over the modeling period.[28] These results for the first year (i.e., the upcoming winter 2023/2024 period) are combined with an assessment of the likely probability of these consequences being realized, based on a qualitative review of the various system conditions and disruptions included in each case. The purpose of combining assessments of both probability and consequence in this way is to focus in on the subset of cases that (a) have the potential for

[28] The model also identifies circumstances where there is no loss of load, but conditions are tight enough to lead to a reduction in energy-only exports, activation of SCR/EDRP, reduced reserves, or all of the above. See [[Sections III and V]].

significant reliability risks, and (b) are probable enough to merit further attention and consideration of whether mitigating action is warranted.

The next section provides a more detailed description of the analytic method, model components, and data and information sources used in the analysis. This is followed by a summary of results.

Figure 3: Structure of Fuel and Energy Security Analysis



III. Analytic Method

A. Framework for Fuel and Energy Security Analysis

Analysis Group's fuel and energy security model is a deterministic, scenario-based assessment of winter system operations subject to a variety of scenarios (different assumptions regarding system topology) and disruptions (primarily episodic changes to the system affecting fuel and resource availability). An initial set of system conditions is identified that define weather, electric and gas demand, and gas and electricity transmission/transportation capacities. Scenarios and disruptions are then combined to define "cases," which are run through the fuel and energy security model to identify any risks associated with winter operations under the assumed conditions.

The starting point for the analysis is expected system conditions for three future winter seasons - the winters of 2023/2024, 2026/2027, and 2030/31. System demand, supply resources, and transfer capabilities are based on previously-vetted NYISO study assumptions, including the 2023 Load & Capacity Data report (commonly referred to as the "Gold Book") and 2021-2040 System & Resource Outlook ("2021-2040 Outlook"). Winter 2023/2024 is largely based on the 2021-2040 Outlook Baseline Case and the 2023 Gold Book, winter 2026/2027 on the 2021-2040 Outlook "Contract Case," and winter 2030/2031 on the 2021-2040 Outlook "Policy 1 Case." In each winter, the fuel and energy security model studies an extended period of cold weather based on analysis of 30 years of historical weather data. The modeled cold weather event spans seventeen days of frigid winter conditions, including a three-day severe cold weather event (occurring on days six through eight of the event). Figure 4 contains a detailed schematic of the fuel and energy security model logic and data sources.

The fuel and energy security model includes the following data and modeling steps, conducted where appropriate for specific locations (load zones or combinations of load zones) within the state:

1. <u>Weather</u>: Identify severe winter conditions based on historical winter weather data, and use this to identify an appropriate extended "severe cold weather event" period in terms of length, daily heating degree days, and including a short period of very severe weather within the duration of the extended event.
2. <u>Electric and Gas Demand</u>: Using historical data, establish locational relationships between temperature (heating degree days) and two factors affecting natural gas use and availability: (a) LDC retail gas demand and (b) electric load.
3. <u>Fuel</u>: Using historical data reported by generation resources to the NYISO, evaluate the likely inventories and refill capabilities for oil-fired (including dual fuel) units.[29]
4. <u>Pipeline Capacity</u>: Using public data from EIA, interstate pipelines, and other sources, estimate the capacity of natural gas infrastructure in New York to deliver natural gas for meeting both LDC retail gas demand and power system needs, net of what is expected to be exported to surrounding states/regions.
5. <u>Natural Gas System Balance</u>: Use items #2 and #4 to determine a *natural gas system balance*, approximating the availability of non-firm natural gas for power generation on a daily basis over the extended severe cold weather event.

[29] Firm gas supply is assumed to be available for approximately 2,500 MW of generating capacity (New York ISO, 2022-23 Winter Assessment & Winter Preparedness, Aaron Markham, NYISO Management Committee, November 30, 2022 at p. 38).

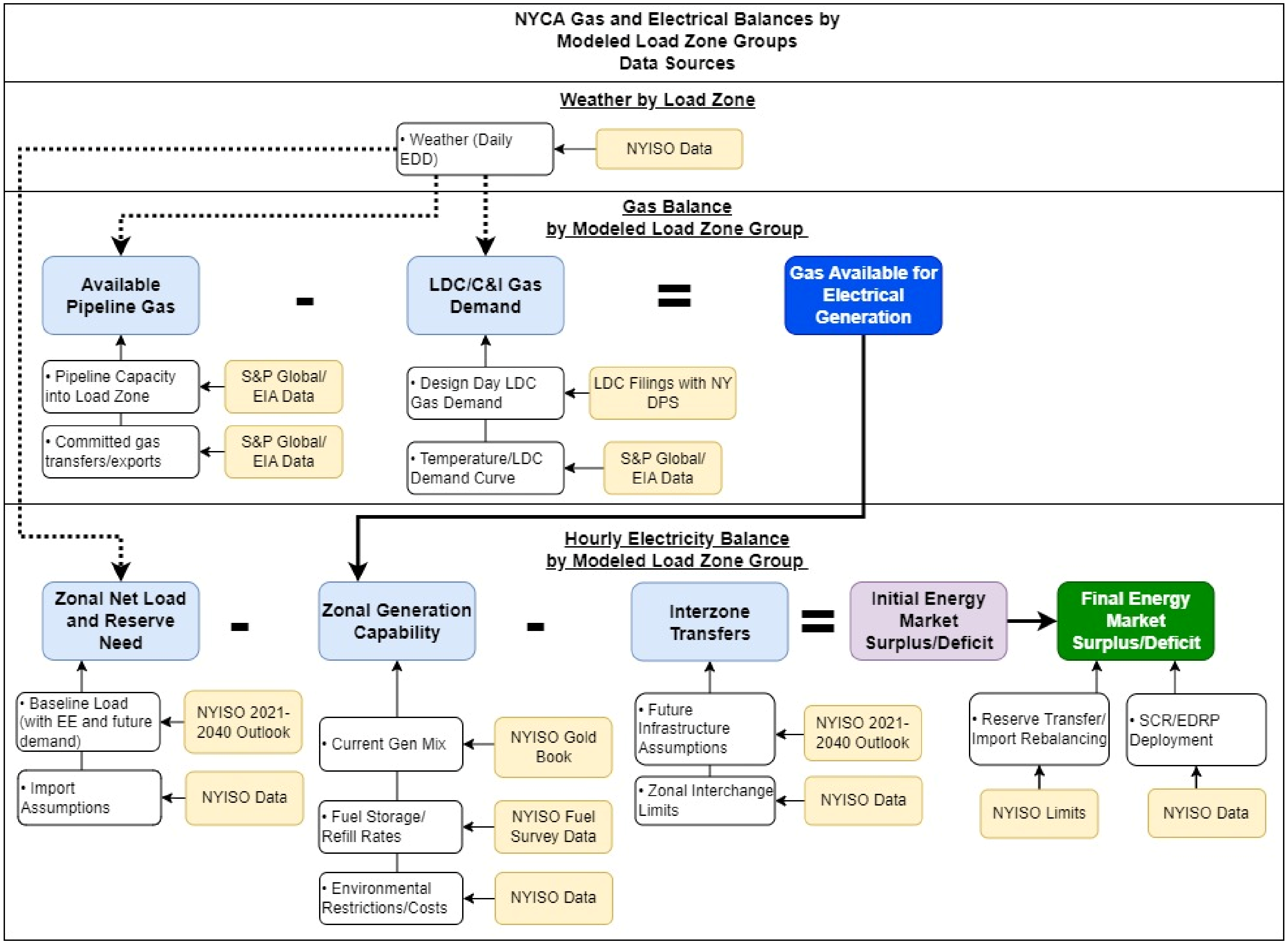
6. Power System Resources: Combining estimates from #5 and data on non-gas resource availability, identify the resources expected to be available for electricity generation under the modeled winter conditions, and stack order them based on likely output, availability of fuel, and operational efficiency, to determine total potential generation and transfers between locations in New York on an hourly basis over the extended severe cold weather event.
7. NYISO Actions: Identify hours where actions to reduce energy-only exports to New England or activate SCRs/EDRP are necessary to meet load or maintain reserves, and model the effect of such actions.
8. Electric System Balance: Compare the hourly zonal demand for energy with the available electric generation (and transfer capability between regions within New York) to identify the *electrical supply/demand balance* on an hourly basis.
9. Case Specification: Identify relevant variations in overall system and fuel infrastructure (scenarios), and potential unexpected events (disruptions), to determine a range of possible futures (cases) to analyze through the model.
10. Reliability Assessment: Run the model for each case; identify the magnitude, frequency and duration of any periods where available generation was potentially insufficient to meet demand plus reserves over the duration of the extended severe cold weather event.

As noted, for each future winter, the model was run for a wide range of cases that vary along two dimensions: "scenarios" represent potential variations in the configuration of resources, fuel availability and power transfers in the future year, and "disruptions" primarily identify episodic conditions that do not necessarily reflect permanent system changes (evaluated singularly or in combination). In total, the analysis assessed system performance under over two hundred "cases," each representing some combination of the identified scenarios and disruptions. Additional cases were also run to test the impact of issues identified by Analysis Group or raised in stakeholder discussions.

For example, starting point oil inventories were based on fuel survey data collected by the NYISO, with many facilities starting without a full inventory of fuel. However, it is possible that market opportunities during an expected period of extended cold could lead asset owners to fill their tanks. Thus, we ran cases with oil tanks full at the start of the modeled cold weather event in order to review the potential impact on resulting outage events. As expected, this "full oil tank" assumption led to a decrease in potential loss of load relative to both the historical starting fuel storage assumption and the high starting fuel storage assumption. However, because oil tanks in several regions are already modeled as full, or close to full, under the high starting fuel storage scenario assumption, the results with full oil tanks were not always notably different from the high starting fuel storage cases. For example, for one winter 2026/2027 case tested, total potential loss of load over the duration of the modeled 17-day cold weather event was 385,991 MWh under the historical fuel oil assumption, 169,563 MWh under the high fuel storage assumption, and 135,682 MWh under the full oil tank assumption.

In the sections that follow, the methods and underlying data used in the model and analyses summarized above are further described. Section B addresses the selection of an appropriate extended severe cold weather event for the modeling period, based on historical winter weather data, and the determination of relationships between the weather data and demand for LDC retail natural gas and electricity in New York State. Next, the various resource assumptions that apply across all cases with respect to generation, transmission, and fuel availability are further described. Following the review of these assumptions, the "dispatch" and intrastate power transfer logic that is applied in running cases is addressed. The final element reviews the metrics used to assess the level of risk associated with case outcomes (in terms of the magnitude, frequency and duration of potential loss of load or other emergency actions), and the assessment of the likelihood of case outcomes.

Figure 4: Fuel and Energy Security Model Steps and Data Sources



B. Construction of Modeling Period and Relationship of Temperature to Demand

The analytic model represents a severe winter weather period during the winters of 2023/2024, 2026/2027, and 2030/2031. The selection of this modeling period was designed to replicate the most severe winter conditions experienced over a sufficiently long event. With the modeling period defined, historical weather data, and corresponding natural gas and electric demand data was used to establish relationships between temperature (heating degree days) and daily/hourly demand.[30] This is the first step in the analysis because these relationships are needed to identify, during the extended severe cold weather event modeled:

1) the demand for natural gas from LDCs to serve retail gas demand on a daily basis;
2) the remaining amount of natural gas available daily for use by natural gas and/or dual-fuel power plants; and
3) the hourly demand for electricity.

This section describes the data and analyses used to (1) construct the modeling period based on historical weather data, and (2) estimate associated natural gas and electricity demand patterns.

1. Analysis of Historical Winter Weather Patterns

A critical variable in analyzing winter fuel security concerns is the weather, which drives both electrical load and retail natural gas demand by end-users. The modeling period is constructed to analyze a severe winter weather event lasting 17 days, which represents an extended 14-day cold period and an extreme 3-day "cold snap" (modeled as occurring over days six through eight of the extended event).

To establish an appropriate extended duration cold weather event, historical hourly weather data by load zone was provided by the NYISO, and analyzed for the years 1993-2023. As seen in Table 1, the period spanning December 25, 2017 through January 8, 2018 was the coldest consecutive 14-day period in the historical data where daily temperatures were in the tenth percentile of wind-adjusted temperatures or lower, with an average temperature across the NYCA of 11.4 degrees F and an average wind-adjusted temperature of -0.8 degrees F.

The fuel security risks caused by extended cold weather may be further exacerbated during short cold snap periods of a few days, when natural gas supply capacity reaches maximum utilization and when fuel oil transportation issues (such as frozen roads or waterways) may interfere with fuel replenishment. Using the NYISO historical data, the period spanning January 18, 1994 through January 21, 1994 was identified as the coldest consecutive 3-day cold snap between 1993 and 2023, with an average temperature across the NYCA of 2.9 degrees F (see Table 2 below).

The temperature profile for the modeling period was constructed by combining the temperatures of the 3-day cold snap with the 14-day cold period, with the cold snap being inserted into the sixth through eighth days of the extended cold weather period.[31] This 17-day modeling period (see Figure 5 below) thus represents an extreme cold weather event equivalent to a historically cold 17-day period from the last 30 years, including the worst-case three-day cold snap during that period. Since the purpose of the analysis is to examine fuel and energy security

[30] Temperature graphs are shown in terms of heating Effective Degree Day (EDD), which is defined as 65 degrees Fahrenheit minus temperature. See National Weather Service, "What are Heating and Cooling Degree Days," available at https://www.weather.gov/key/climate_heat_cool.

[31] The sixth day was selected day to coincide with the first cold "peak" in the historical 14-day cold weather period.

risks under severe winter conditions, this 17-day period is used in all three winters as the model baseline for estimates of LDC retail gas demand, availability of natural gas for power generation, and hourly electrical demand.

Table 1: Extreme Weather Events Lasting over 14 Days

Cold Snap Period	Number of Days	Average Wind-Adjusted Temp (F)	Average Unadjusted Temp (F)	% Increase of Avg. Daily Energy Above Winter Baseline
12/19/2000 - 01/05/2001	17	10.6	20.7	3.1%
01/10/2003 - 01/28/2003	18	3.8	15.2	6.0%
01/18/2004 - 02/01/2004	14	2.1	14.6	8.2%
01/14/2005 - 01/29/2005	15	1.2	12.4	10.1%
02/02/2007 - 02/19/2007	17	4.6	17.4	9.0%
02/07/2015 - 02/21/2015	14	3.1	14.0	10.1%
12/25/2017 - 01/08/2018	14	-0.8	11.4	13.3%

Notes:
[1] Wind-Adjusted Temperature is calculated using the Wind-chill formula from Weather.gov, valid for temperatures (T) at or below 50 degrees F and wind speeds (W) above 3 mph: WindChill = 35.74 + (0.6215 × T) - (35.75 × W^0.16) + (0.4275 × T × W^0.16).
[2] Percentage Increase of Avg. Daily Energy Above Winter Baseline is calculated using: ((Average daily system load during cold snap - 50th percentile daily system load for that winter)/50th percentile daily system winter load for that winter).
[3] Daily load calculated by first summing hourly load and then averaging over the period of the cold snap.

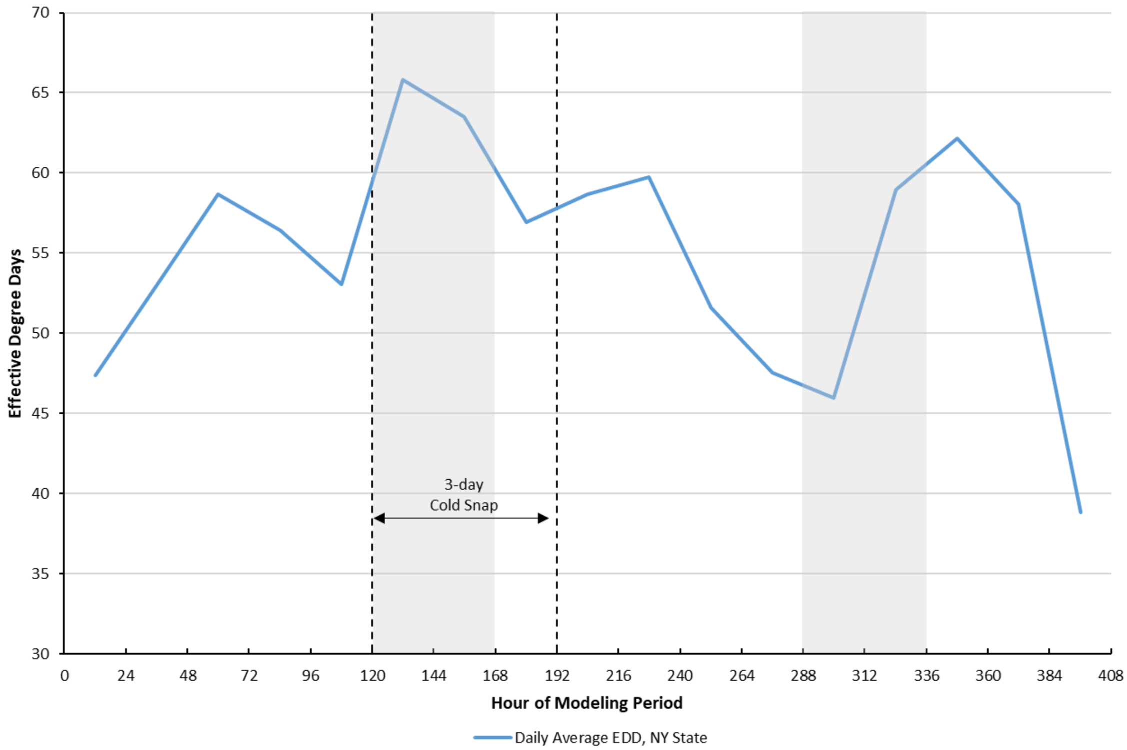
Sources:
NYISO Weather Data 1993-2023; NYISO Hourly Load Data 1993-2023.

Table 2: 3-Day Cold Snaps

Winter	3-day period w/min temperature	Average Temp during 3-day min temp period
1993 - 1994	01/18/1994 - 01/21/1994	2.9
2003 - 2004	01/13/2004 - 01/16/2004	3.4
2004 - 2005	01/20/2005 - 01/23/2005	5.2
2017 - 2018	01/04/2018 - 01/07/2018	5.3
1995 - 1996	01/04/1996 - 01/07/1996	5.8

Source:
NYISO Weather Data 1993-2023; NYISO Hourly Load Data 1993-2023.

Figure 5: Daily Temperatures During 17-Day Modeling Period



Notes:
[1] Weekends are shaded in gray.
[2] Effective degree day is defined as 65 degrees F - Temperature.
Source:
[1] NYISO Weather and Load Data 1993-2023.

2. Relationship of LDC Retail Gas Demand to Weather

A key driver in the analysis and results is the quantity of natural gas generation available to support gas-fired generation during cold winter weather. Under these conditions, New York LDC retail demand for natural gas is at its highest, and firm transportation through New York to external regions (for both LDC retail demand and power generation) is also at its highest. This can constrain the amount of non-firm natural gas available to support electricity generation in New York, having two effects critical to maintaining reliability: (1) it can potentially limit or preclude the dispatch of gas-only units, and (2) it can force dual-fuel units to operate more frequently over the modeling period on oil, drawing down oil inventories and requiring more frequent and more rapid oil inventory replenishment to maintain availability of oil production capability.

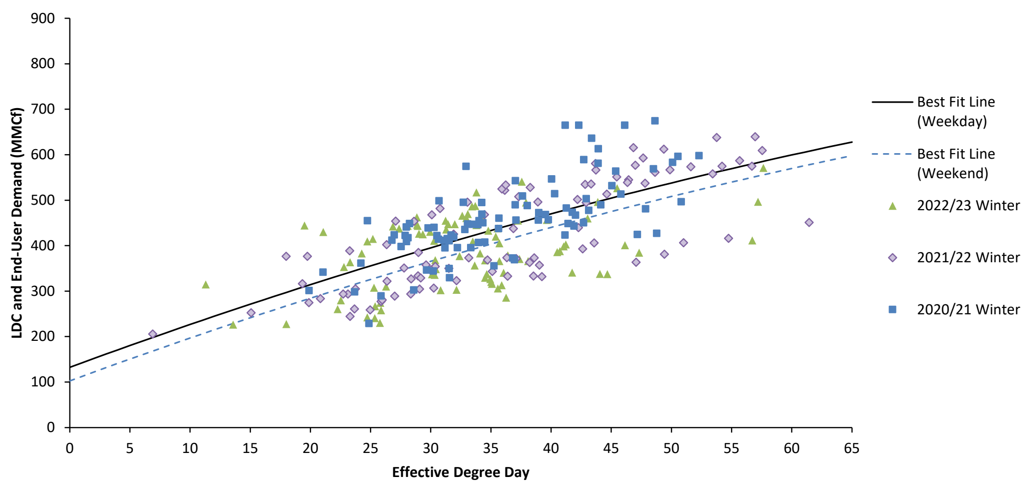
The starting point then is to estimate the amount of natural gas available to support electric generation during the modeling period by estimating the consumption by natural gas LDCs under these same winter conditions. This is done by establishing the historical relationship between LDC retail natural gas demand and temperature.[32] With

[32] Data on LDC retail gas demand is from S&P Global Market Intelligence and represents deliveries to LDCs and end-users during the intraday 3 nomination cycle. Data on historical temperatures by load zone was provided by the NYISO.

this relationship in hand, the model uses the temperature pattern defined for the extended severe cold weather event to predict daily LDC retail gas demand throughout the seventeen-day event.

Data from three winters (2020/2021, 2021/2022, and 2022/2023) are used to estimate the statistical relationship between LDC retail gas demand and temperature separately for upstate and downstate.[33] Figure 6 and Figure 7 below show these relationships. Next, this modeled relationship is calibrated to LDC retail natural gas demand during the LDC's design day.[34] A gas design day is defined as 65 EDD downstate, and 75 EDD upstate. The statistical models are calibrated to the LDCs' filed design day demand by multiplying the modeled LDC retail gas demand based on the temperature in each day of the modeling period by a scaling factor. The scaling factor is equal to the filed LDC design day capability for all upstate/downstate LDCs divided by the modeled LDC retail gas demand at the design day temperatures of 75 EDD for upstate and 65 EDD for downstate.

Figure 6: Relationship between Degree Day and LDC/C&I Demand, Upstate

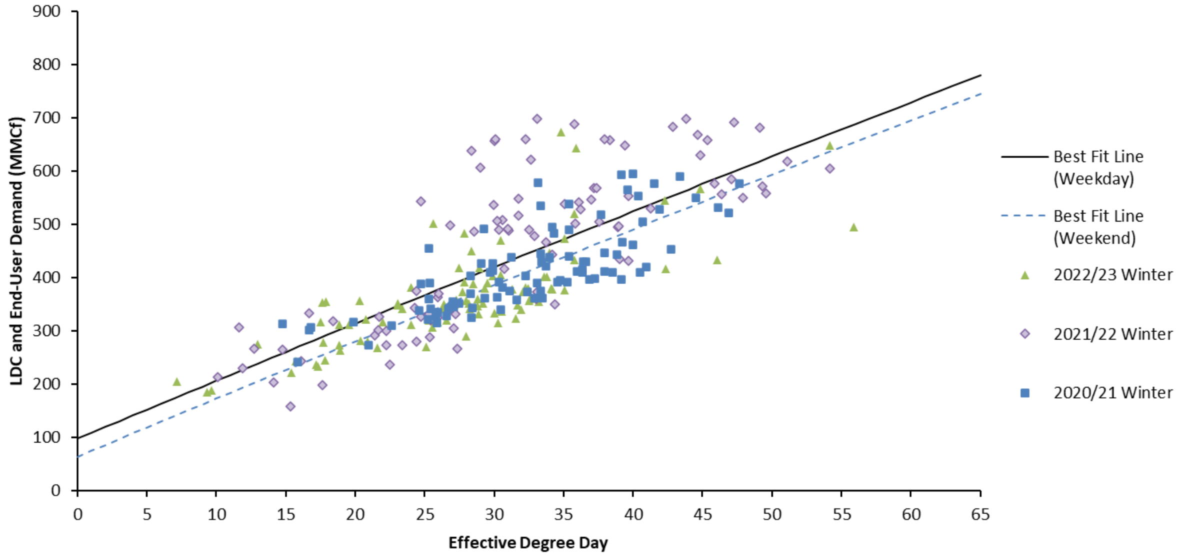


Notes:
[1] Total deliveries are the sum of scheduled capacity during the intraday 3 nomination cycle to LDCs, End Users, and select Pool points. Chart includes all Load Zone A, B, and C gas points not located right next to a gas power plant.
[2] Winter is defined as December, January, and February.
[3] Effective degree day is defined as 65 degrees - Dry Bulb Temperature, and is taken as the simple average of Load Zones A, B, and C temperature data.
Sources:
[A] LDC and End-User Demand: S&P Global Market Intelligence.
[B] Temperature: NYISO.

[33] The upstate graph includes the following data: a simple average of historical temperatures in load zones A through C and all gas delivery to LDC or delivery to end user points not located immediately next to a power plant in counties in load zones A through C. The downstate graph includes the following data for Rockland and Westchester counties: a simple average of historical temperatures in load zones H and I, and all gas delivery to LDC or delivery to end-user points not located immediately next to a power plant in Rockland and Westchester counties.

[34] "Design day" is the maximum daily retail gas demand estimated by each natural gas LDC at historically cold temperatures, and serves as the basis for LDC natural gas supply and transportation planning. Each LDC in New York State annually files a design day gas demand forecast and a supply plan to meet that demand with the NYS Department of Public Service. See, for example, Consolidated Edison Company, Inc., Case 22-M-0247 – Winter Supply Review Data Request, August 3, 2022, available at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=68031 &MNO=22-M-0247.

Figure 7: Relationship between Degree Day and LDC/C&I Demand, Downstate



Notes:
[1] Total deliveries are the sum of scheduled capacity during the intraday 3 nomination cycle to LDCs, End Users, and select Pool points. Chart includes all Westchester and Rockland county gas points not located right next to a gas power plant.
[2] Winter is defined as December, January, and February.
[3] Effective degree day is defined as 65 degrees - Dry Bulb Temperature, and is taken as the simple average of Load Zone H and Load Zone I temperature data.
Sources:
[A] LDC and End-User Demand: S&P Global Market Intelligence.
[B] Temperature: NYISO.

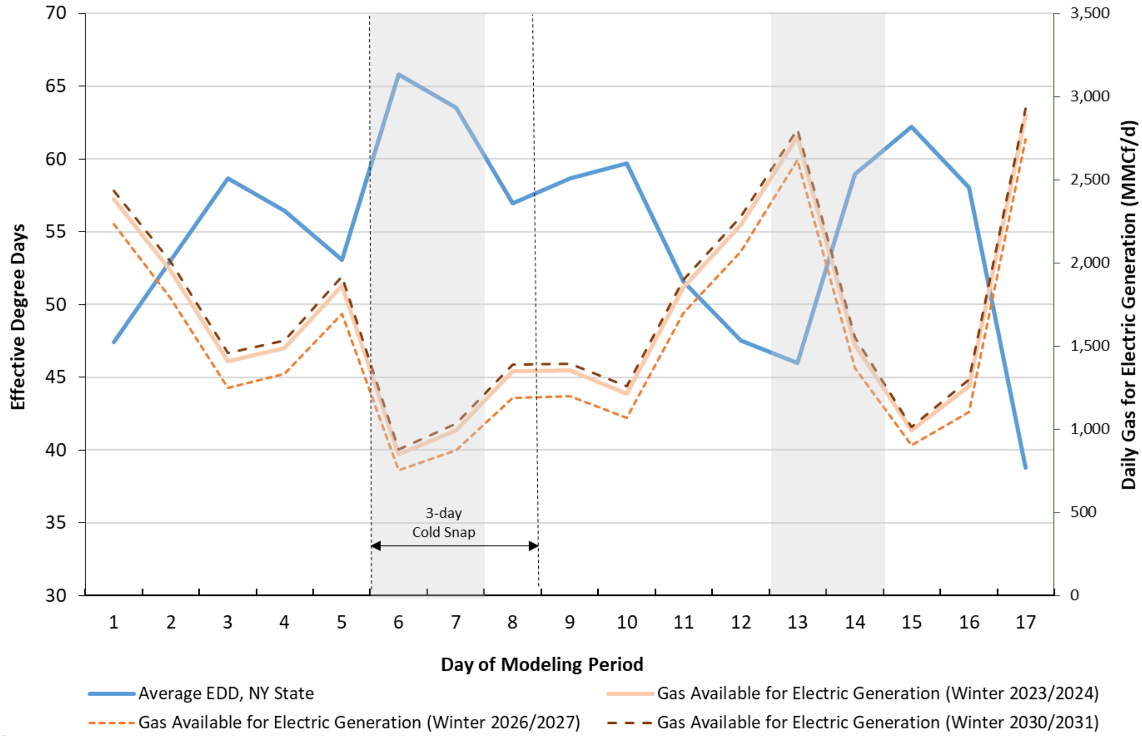
Finally, the scaled LDC retail gas demand on each day of the modeling period is subtracted from the total natural gas pipeline capacity available in New York State (net of firm transportation through New York to external areas)[35] to determine the amount of remaining natural gas on a daily basis available to support electric generation. The daily gas available for electrical generation is spread equally across all 24 hours in a day to produce an hourly amount of gas available to electric generators based on each day's average temperature. As illustrated in Figure 8 below, the amount of natural gas available for electric generation is the total available pipeline capacity minus the firm LDC gas demand.

Figure 8: Diagram of Natural Gas Model

Figure 9 below shows how gas available for electric generation varies with daily EDD during the modeling period for each future winter. The quantity of available pipeline gas is assumed to remain unchanged across each future winter. By contrast, as described in more detail in Appendix B.3, LDC retail gas demand is estimated for winters 2026/2027 and 2030/2031 based on projected peak demand growth rates in LDC filings to the NYS Department of Public Service.

[35] See Appendix B.6 for detail on New York State's natural gas supply.

Figure 9: Gas Available for Electric Generation during 17-day Modeling Period



Notes:
[1] Weekends are shaded in gray.
[2] Effective degree day is defined as 65 degrees F - Temperature.

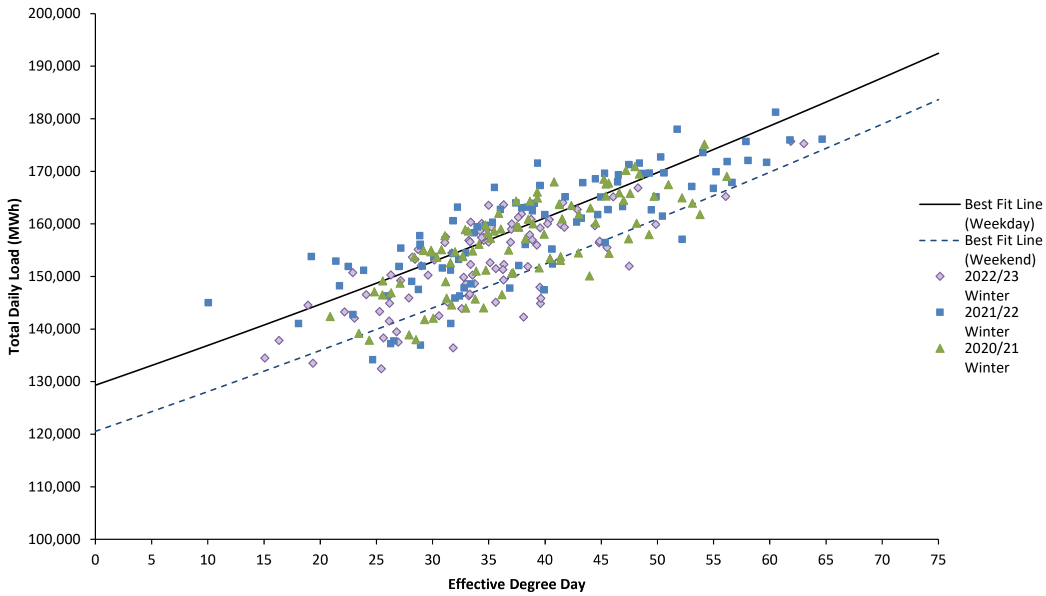
3. Relationship of Zonal Load and Weather

The next key factor in the analysis is the hourly demand for electricity under the modeled weather conditions. Hourly electricity demand during the extended severe cold weather event depends on the assumed temperature pattern, increasing during colder days and decreasing during milder days, but also observing a pronounced daily cycle. In order to specify hourly electricity demand during the modeling period, a forecast of load was established based on the historical relationship between load by load zone and temperature.[36]

Data from three winters (2020/2021, 2021/2022, and 2022/2023) are used to estimate the statistical relationship between total daily energy and temperature for each modeled load zone group/region (load zones A-E, F, G-I, J, and K). Each modeled region showed a similar pattern of daily load that increased with increasing heating degree days, along with significantly lower loads on weekends (see Figure 10 below illustrating the electric load pattern for load zones A-E).

[36] Data on historical loads and temperatures by load zone was provided by the NYISO.

Figure 10: Historical Winter Load and Best-Fit Line, Load Zones A-E 2020-2023



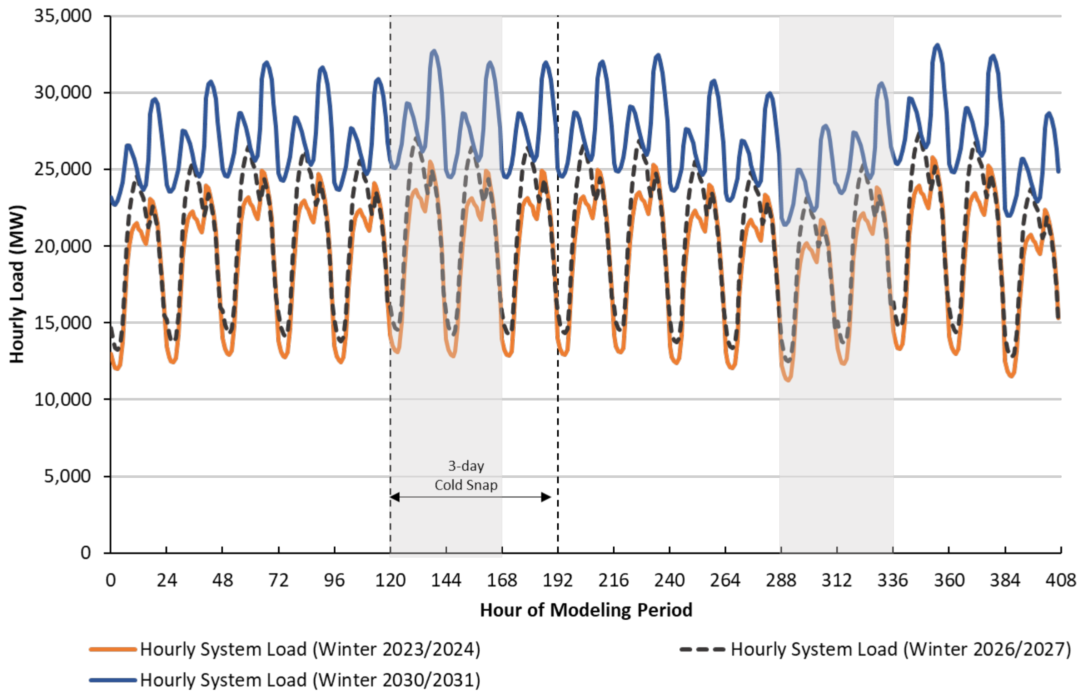
Notes:
[1] Winter is defined as December, January, and February.
[2] Effective degree day is defined as 65 degrees - Temperature.
Source:
[A] Load and Temperature: NYISO.

In order to construct a 17-day hourly load shape consistent with temperature and intraday load fluctuations, a single-day hourly load shape was scaled such that each day's modeled zonal total load matches the predicted zonal total load from the temperature/load forecast described above.[37] For each future winter, this single-day hourly load shape is based on the peak day of that winter from the 2021-2040 Outlook (more detail on these daily load shapes is provided in Appendix B.1). As a final step, winter peak loads were benchmarked to expected peak load for the relevant winter.[38] The final modeling period load shape for each future winter is shown in Figure 11, with peak load in the modeling period of 25,795 MW (for winter 2023/2024), 27,371 MW (for winter 2026/2027), and 33,096 MW (for winter 2030/2031).

[37] The load/temperature relationship for each load zone is used to model that load zone's predicted load.

[38] This benchmarking was accomplished through the application of a constant scaling factor to loads across the modeling period hours. For winter 2023/2024 and winter 2026/2027, the peak load for this calibration is based on 2023 Gold Book Table 1-7c (90th Percentile Winter Peak Demand Forecast), Table 1-7e (99th Percentile Winter Peak Demand Forecast), and Table I-20 (Peak Day Weather Distributions). The statewide average temperature on the coldest day during the modeling period falls between the 90th and 99th percentile temperatures in Table I-20. Therefore, the modeling period peak demand is calculated correspondingly as falling between the 90th and 99th percentile peak demand forecasts for the future winter. For winter 2030/2031, the peak load for this calibration is based on the hourly peak in the 2021-2040 Outlook "Policy Case 1" load forecast.

Figure 11: Hourly Loads During 17-Day Modeling Period



Note:
[1] Weekends are shaded in gray.
Source:
[1] NYISO Weather and Load Data 1993-2023.

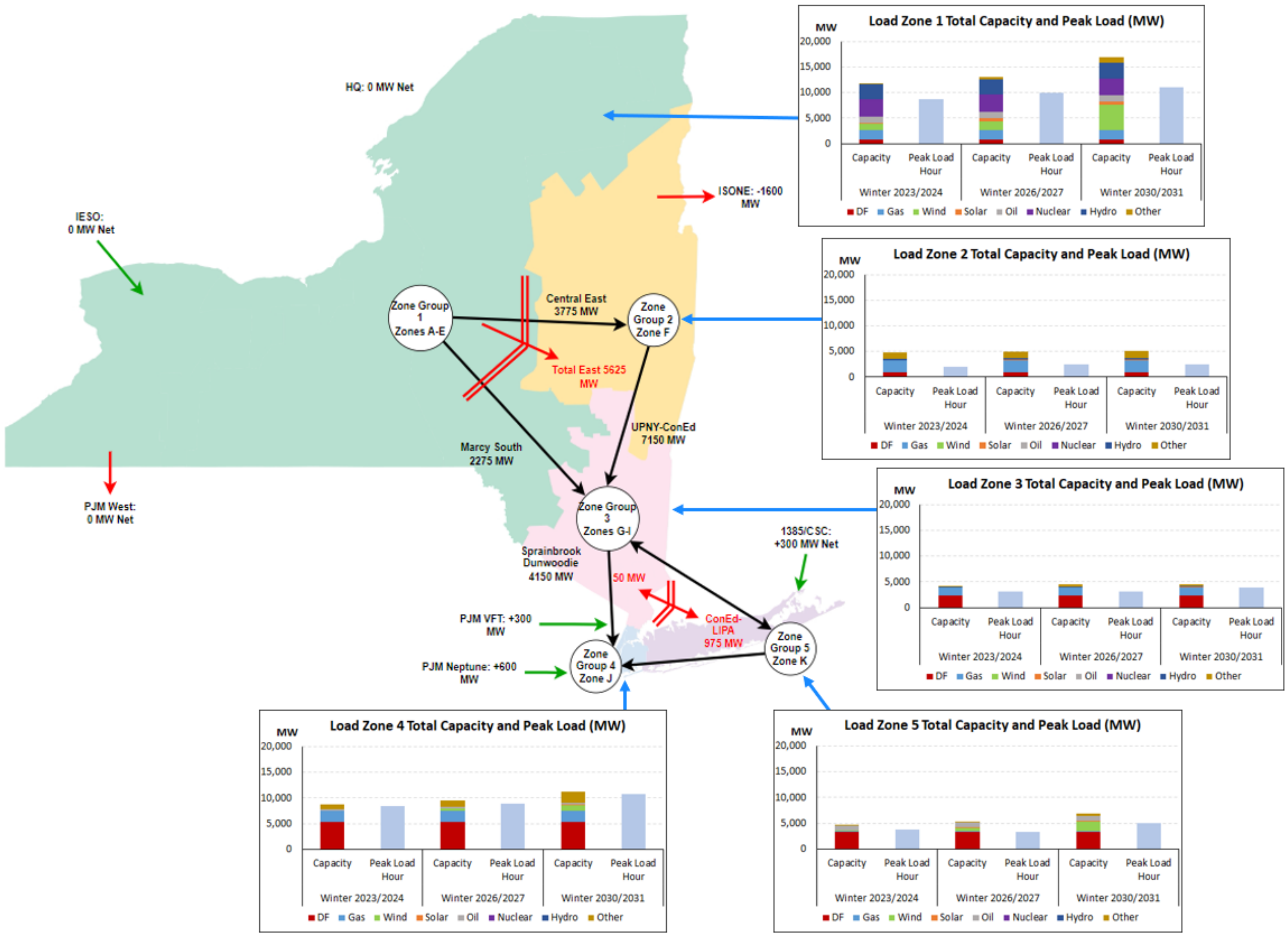
C. Common Inputs

This section describes the sources of data underlying the analytic model. The model primarily uses the 2023 Gold Book and 2021-2040 Outlook as a starting point for load and generation assumptions. Figure 12 presents a summary of key generation capacity/fuel mix, modeling period peak demand, interregional transfers, and zonal transfer capability values that are built into the model.

1. Load

The underlying hourly load profiles from the 2021-2040 Outlook, along with peak load forecasts from the 2023 Gold Book, were a main input into the load modeling as described in Section III.B.3.

Figure 12: Fuel and Energy Security Model Input Summary



Note: Other includes Pumped Storage, Battery Storage, Steam, and Other (Flywheel, Refuse, and Bio Gas). All capacity is derated.

2. Generation

The existing generation fleet used in our model is based on the units listed in-service in the 2023 Gold Book.[39] For winter 2023/2024, resource additions are based on the 2021-2040 Outlook "Baseline Case."[40] Winter 2026/2027 resource additions are largely based on the 2021-2040 Outlook "Contract Case."[41] Incremental resource additions between winter 2026/2027 and winter 2030/2031 are based on the 2021-2040 Outlook "Policy Case 1" capacity expansion additions.[42]

Generator deactivations are based on the 2023 Gold Book.[43] Units scheduled for deactivation are included in the modeling period for future winters prior to their deactivation. For example, a unit scheduled for deactivation in 2025 would be included in the winter 2023/2024 modeling period and excluded from the winter 2026/2027 and winter 2030/2031 modeling periods.

While fossil resources are dispatched according to the stacking order established in the model (as described in Section III.D.1), renewables are dispatched using hourly profiles. Wind and solar output comes directly from the 2021-2040 Outlook.[44] The underlying load shape for the 2021-2040 Outlook is based on data from 2002.[45] As such, the coldest 17-day period in the winter 2002 was identified, and the predicted renewable output from the 2021-2040 Outlook during those 17 coldest days was used as the wind and solar output in the model.[46]

The model assumes that these new battery storage facilities run on a daily charge/discharge cycle where batteries discharge at capacity between 4 PM and 8 PM, and charge during the night between 1 AM and 5 AM, using a round-trip efficiency of 85%. Moreover, to avoid expending fuel oil to charge batteries, the model only charges batteries in a load zone if excess non-thermal generation is available after meeting load in that load zone.

For other non-fossil fired resources (including hydro, pumped storage, and nuclear), the output profiles used are based on historical winter operations and average winter outages. For a detailed discussion see Appendix B.2.

3. Transmission Limits and Imports

In order to model geographic constraints on electrical generation and transmission, a simulated and simplified version of the NYISO transmission network is used in the fuel security model. New York has a concentrated geographic distribution of load downstate, but generation capacity is limited downstate, so a large amount of power must flow over transmission lines from upstate to downstate. The NYISO divides the state into 11 geographic load zones, labeled as load zones A through K, which are interconnected through transmission. In order to reduce the number of transmission lines required to be modeled, the model simplifies the network to 5 regions: "Region 1" represents load zones A-E, "Region 2" represents load zone F, "Region 3" represents load zones G-I, "Region 4" represents load zone J, and "Region 5" represents load zone K. In determining hourly electrical flows, transmission transfer limits based on an N-1-1 contingency analysis, as provided by the NYISO (see

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[39] 2023 Gold Book, Table III-2a.

[40] 2021-2040 Outlook, Data Documents, "Contract Case Renewable Projects."

[41] 2021-2040 Outlook, Data Documents, "Contract Case Renewable Projects."

[42] 2021-2040 Outlook, Data Documents, "Outlook Policy Case Additions."

[43] 2023 Gold Book, Tables IV-4, IV-5, and IV-6.

[44] 2021-2040 Outlook, Data Documents, "MMU Renewable Profiles."

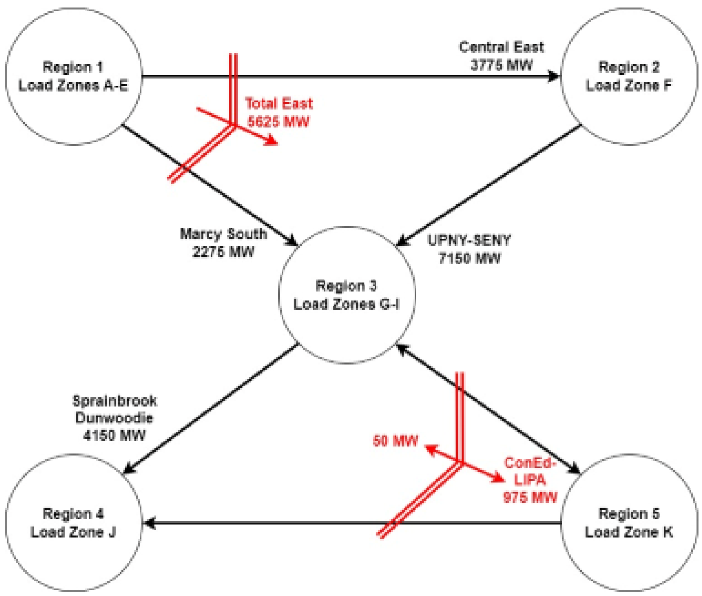
[45] 2021-2040 Outlook, Appendix C, September 22, 2022, available at https://www.nyiso.com/documents/20142/33395392/2021-2040-Outlook-Appendix-C.pdf/ca02e79f-a0e7-e0d6-cb17-5be775793e77.

[46] The coldest period during the calendar year 2002 was identified using historical weather data from the NYISO. The coldest period was between December 1- 17, 2002, so the model uses predicted wind and solar output from December 1-17 in the 2021-2040 Outlook profiles.

Figure 13), were used. Figure 13 includes the recently completed Western New York and nearly completed AC Transmission Public Policy Transmission Need upgrades.

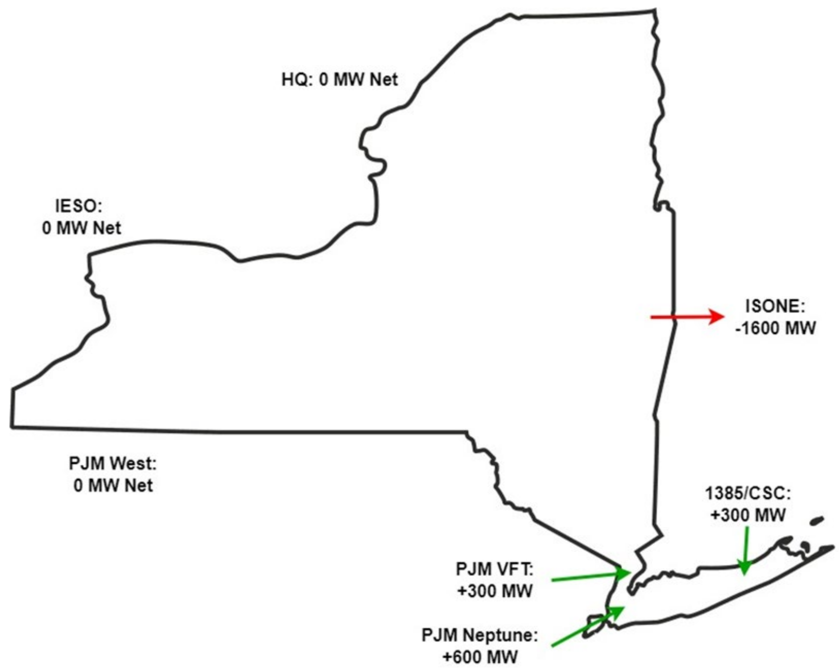
In addition, the Clean Path New York transmission project is assumed online by winter 2030/2031 and is modeled as a constant 1,200 MW transfer from load zones A-E to load zone J. The Champlain Hudson Power Express transmission project is not considered in the model; because Quebec is a winter peaking system we assume that no power would be delivered from Quebec during a cold winter period.

Figure 13: Simplified Transmission Map and Limits



In addition to interzonal transfers, a fixed quantity of capacity imports and energy-only exports to neighboring regions were assumed during the modeling period. By default, 1,600 MW of energy-only exports to ISO-NE were assumed in each hour. The level of capacity imports from PJM over the Linden VFT and Neptune transmission lines varied between either 900 MW or 0 MW depending on the scenario evaluated, and the level of capacity imports from ISO-NE over the Cross Sound Cable is 300 MW in every scenario. The assumed flows for scenarios including 900 MW of capacity imports from PJM, and 300 MW from ISO-NE are represented in Figure 14.

Figure 14: Import and Exports During Modeling Period



4. Oil Replenishment

A central component to fuel security in New York is the ability of resources with inventoried energy to replenish their fuel stock. There were two assumptions required to model oil replenishment capability: starting level of oil inventory and refill rates (that is, the rate at which a resource can refill its stored oil). Both the starting inventory and refill rates were developed using information reported by generators to the NYISO, and is discussed further in Appendix B.2.

Starting inventory was developed based on a unit's storage size, refill type, and location. There are three ways oil is replenished in New York: barge, truck, and pipeline. Storage tanks that refill by truck tend to be smaller in size than those that refill by barge. Zonally, resources downstate have historically started the winter with higher levels of storage. The average starting level as a share of max tank size was applied to each resource's tank to determine the starting level. It was assumed that a resource would not replenish above its starting storage level.

Refill rates or capabilities are based on the information provided by each resource to the NYISO, as well as a review of historical refueling patterns in weekly data collected by the NYISO. These rates were used to model resource refill level capabilities. Additionally, a refill threshold was established for each resource. Once the storage level dropped below this threshold, the resources refilled at its stated capability until it either crossed the refill threshold or reached its starting inventory level.[47]

[47] In some cases replenishment assumptions were set based on NYISO information related to specific resources.

D. Representation of Electric System Operations Under Winter Conditions

1. Transfer and Dispatch Logic

In order to determine how the electric system operates under cold winter conditions during the 17-day modeling period, electrical transfers and generation across New York were modeled using the 5-region transmission framework discussed in Section III.C.3. The electric system model is designed to meet all load needs and reserve requirements using available resources given transmission and operational constraints.[48]

In each hour, the model first prioritizes meeting load in each region (see Section III.B.3 for a full description of construction of the load profile). Next, the model attempts to meet the nested zonal reserve requirements, shown in Table 3. For the purposes of the model, all fossil units are assumed to be capable of providing reserves.

Table 3: Regional Reserve Requirements[49]

Region	Reserve Requirement (MW)
NYCA	2,620
Total East (F-K)	1,200
SENY (G-K)	1,800
NYC (J)	1,000
LI (K)	540

Source:
[1] NYISO Operations.

In the first step of the model, non-fossil generation is dispatched in each modeled region and then transferred throughout the state to maximize load served. Solar and land-based wind units are assumed to generate based on hourly profiles used in the 2021-2040 Outlook (see Section III.C.2). Hydroelectric and nuclear units are assumed to generate at fixed capacity factors based on historical winter averages and do not respond to load.[50] Load within each region is assumed to be served by non-fossil generation in that region first, followed by a modeling of inter-region electric transfers to distribute regional generation surpluses across the state. In the next step of the model, fossil units are dispatched as needed to meet load and reserve requirements. Fossil units of different fuel types are run in the following order during the modeling period:

1. Natural Gas Only (to extent non-firm gas is available excluding resources with firm gas supply)
2. Dual Fuel using natural gas as fuel (to extent non-firm gas is available)
3. Dual Fuel using oil as fuel (to the extent oil inventory is available)

[48] Note, however, that the analysis is not a production cost model which takes prices into account for unit dispatch.

[49] Note that while the SENY 30-minute reserve requirement varies from 1,300 to 1,800 MW depending on peak versus off-peak times of day, the 1,800 MW requirement is assumed to apply in all hours for the purposes of this analysis. A similar assumption is made for the Long Island 30-minute reserve requirement that varies between 270 MW and 540 MW. The 540 MW reserve requirement is assumed to apply in all hours for the purposes of this analysis. New York Independent System Operator, Locational Reserve Requirements, available at https://www.nyiso.com/documents/20142/3694424/Locational-Reserves-Requirements.pdf.

[50] The Niagara hydroelectric plant is assumed to output on a daily cycle, with greater output during the day (hours 9-20) and less output during the night.

4. Oil Only (to the extent oil inventory is available)

Within each resource/fuel type, more efficient units are dispatched before less efficient units. The dispatch order ensures that all natural gas available to support electricity generation in a given hour is used up before any oil is used for generation in that hour. Modeled inter-region electrical transfers mean that when gas is available upstate, it can support load downstate. Hourly liquid fuel inventory is tracked at a plant level, and oil is refilled as described in Section III.C.4.

2. Possible NYISO Actions

After all deliverable generation is dispatched, two types of NYISO actions are modeled as undertaken in hours when reserves would be violated or load would otherwise be unserved. First, the model can reduce energy-only exports to ISO-NE in any hours with potential reserve deficiencies. For example, the default assumed level of energy-only exports to ISO-NE (1,600 MW) can be reduced down to 300 MW, thus preserving fuel for generation within the NYCA. Second, if reserve deficiencies or load losses would still exist after exports are reduced to 300 MW, SCRs/EDRP are activated. The model assumes that SCRs/EDRP can provide up to 4 hours of load reduction capability per activation for a maximum of 5 days during the modeling period. The assumed SCR/EDRP capabilities by modeled region are listed in Table 4. While we model SCR/EDRP capabilities based on historical levels and assumptions about activation fatigue, we recognize that over time SCR/EDRP levels could increase and could reliably operate beyond our assumed limits of 4 hours/5 days, potentially reducing or – in a few cases – eliminating incidence of potential loss of load.

Table 4: Winter SCR and EDR Capacity

Region	SCR + EDRP Capacity (MW)
Load Zones A-E	454
Load Zone F	56
Load Zones G-I	52
Load Zone J	224
Load Zone K	17

Source:
[1] NYISO Gold Book 2023, Table I-17

IV. Cases Analyzed: Combinations of Scenarios and Disruptions

In order to test the operation of the electrical system against different possible system conditions during cold weather events, a number of cases were evaluated in the analysis. These cases are organized around two dimensions: First, a set of "scenarios," which are each a starting point for the electrical system during the modeling period. Second, these scenarios are assessed against a set of "disruptions," which are primarily intended to simulate possible short-term adverse events (evaluated singularly or in combination) that coincide with the modeling period. The scenarios and disruptions are combined into a series of cases, the results of which were analyzed. The sections that follow summarize the scenarios and disruptions that make up the cases reviewed.

A. Scenarios: Variations in Electric System Conditions

In winter 2023/2024, four primary scenarios were developed to represent different configurations of the following system conditions – (1) the level of assumed capacity imports from neighboring regions, and (2) the level of assumed starting oil tank levels. For winters 2026/2027 and 2030/2031, four additional scenarios were added, to make eight total primary scenarios for these model years, capturing the timing and potential delay for the buildout of new renewables. Given that there is more certainty around which renewables will be online in this coming winter 2023/2024, the scenarios capturing a potential delay in renewable resource buildout are only applicable in the two later winters (i.e., 2026/2027 and 2030/2031). The system condition variations summarized below, and Table 5 shows how they are configured for each of the eight primary scenarios.

Table 5: System Scenarios

	Imports	Oil	Infrastructure
Scenario Description	**IM All:** 1,200 MW capacity imports / minimum 300 MW capacity exports **IM Net0:** 300 MW capacity imports / minimum 300 MW capacity exports	**HFS:** Higher starting oil tank levels, 50% increase in starting storage levels	**REN:** Delayed construction of renewables as follows: *Winter 26/27:* 33% decrease of utility solar and land-based wind capacity from 2021-2040 Outlook "Contract Case" additions *Winter 30/31:* 20% decrease of utility solar, land-based wind, and offshore wind capacity 2021-2040 Outlook "Policy Case 1" additions
Scenario 1	IM All		
Scenario 2	IM Net0		
Scenario 3	IM All	HFS	
Scenario 4	IM Net0	HFS	
Scenario 5	IM All		REN
Scenario 6	IM Net0		REN
Scenario 7	IM All	HFS	REN
Scenario 8	IM Net0	HFS	REN

Note: For the upcoming winter 2023/2024 period, only scenarios one through four are applicable.

1. Capacity Imports from Neighboring Regions

In short-term periods of severe winter conditions in New York, similar conditions are likely to be affecting the NYISO's neighboring regions concurrently. Additionally, uncertainty exists as to the level of capacity imports into New York that will be attained in future years. To account for these uncertainties, two possible levels of capacity imports from PJM and ISO-NE to the downstate region are modeled across various scenarios: (1) 900 MW of imports from PJM over the Linden VFT and Neptune lines into New York City and Long Island, and 300 MW of imports from ISO-NE over the Cross Sound Cable into Long Island, for a total of 1,200 MW of imports (i.e., referred to as "IM All"), and (2) 0 MW of imports from PJM, with the 300 MW of imports from ISO-NE maintained (i.e., referred to as "IM Net0"). In both cases, a minimum of 300 MW is exported to ISO-NE.

2. Oil Inventory Starting Point

Oil inventory and storage levels are critical in periods of cold weather to retain reliability when renewable generation may be diminished or unavailable, and natural gas demand is prioritized for heating needs over electric generation. Two possible levels of oil inventory at the start of the modeling period are modeled: (1) historical oil inventory levels based on the NYISO generator fuel survey, and (2) a high fuel storage ("HFS") condition represented as a 50 percent increase in the historically observed starting oil tank storage levels.[51] If the 50 percent increase from historical levels results in the tank for any given unit being more than 100 percent full, the generator's oil inventory starting point is capped at 100 percent.

3. Renewable and Clean Energy Resource Additions

Wind and solar generation, as well as energy storage, are assumed to be built in the 2021-2040 Outlook at a rapid pace which will increase total renewable capacity in New York incrementally by each winter modeled to 2030/2031. There is a good degree of certainty around the amount of new renewables expected to be online for the upcoming 2023/2024 winter period. However, for the future winters modeled (i.e., 2026/2027 and 2030/2031), there is no guarantee that the schedule of new renewable additions assumed by the 2021-2040 Outlook will be fulfilled on time. In order to account for possible circumstances that could delay the build out of new renewable capacity, scenarios were modeled in winters 2026/2027 and 2030/2031 where the new renewables additions are delayed. For winter 2026/2027 the potential delay is modeled as a 33 percent decrease of utility solar and land-based wind resources from the 2021-2040 Outlook "Contract Case" additions. For the winter 2030/2031 period, the potential delay is modeled as a 20 percent decrease of utility solar, land-based wind, and offshore wind resources from the 2021-2040 Outlook "Policy Case 1" additions. The delay percentages in each winter were selected to simulate the potential for a one year delay in the projected renewable buildout.[52]

B. Disruptions: Episodic Interruptions of Fuel and/or Resources

In addition to the development of scenarios, a primary set of event-driven interruptions impacting system operations (one of which is no disruptions or "Disruption 1") were developed. These events are referred to as "disruptions." These primarily relate to unexpected capacity out of service, or interruptions in one form or another in the supply of natural gas or fuel oil. All eleven disruptions were modeled in all three winters analyzed. The disruptions analyzed are summarized below and presented in Table 6.

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[51] The HFS condition results in most fuel oil lank inventories being modeled as full or close to full at the beginning of the 17-day cold weather event.

[52] For winter 2026/2027, 33 percent represents a one-year delay in the 2021-2040 Outlook "Contract Case" cumulative additions assumed online in the three years between model year 2023/2024 and 2026/2027. For winter 2030/2031, the 2021-2040 Outlook "Policy Case 1" provides capacity additions data in five-year increments. 20 percent represents a one-year delay in the 2021-2040 Outlook Policy 1 Case cumulative additions assumed online in the five years between 2025 and 2030.

1. Infrastructure (Disruptions 2-4)

Disruptions related to unit outages are identical to the 2019 FESA. During the 17-day modeling period, the NYISO could lose generating capacity due to unexpected physical breakages or transmission failures. The study assessed the location and severity of these generating capacity losses using three alternatives: 1) Loss of unspecified capacity by doubling each unit's winter-specific historic equivalent forced outage rate (EFORd), which leads to a decrease of 3,219 MW in generating capacity across NYCA, as compared to the initial starting point assumptions of 1,609 MW of unavailable capacity (this is referred to in Table 6 as the "High Outage" or "Disruption 2"); 2) Loss of approximately 1,000 MW of oil-fueled (or dual fuel) capacity in the load zones G-I (this event is referred to as the "SENY Deactivation" disruption in Table 6 or "Disruption 3"); and 3) Loss of a major nuclear facility upstate representing the loss of Nine Mile 1 and 2 (referred to as the "Nuclear Station Outage" disruption in Table 6 or "Disruption 4").

2. Oil Storage and Refill Restrictions (Disruptions 5-7)

Disruptions related to oil storage and refill are identical to the 2019 FESA. Oil stocks on hand are important to the ability of the system to compensate for losses in natural gas supplies and/or other generation output. However, there are a number of possible contingencies that could cause unit refill rates to drop or prevent certain types of refill altogether. For example, during previous cold periods, the rivers around New York City have frozen solid, which made it impossible for oil units on the rivers to refuel by barge. The impact of oil disruptions was tested with four disruptive events: 1) Loss of truck refueling (referred to as the "No Truck Refill" disruption in Table 6 or "Disruption 5"); 2) Loss of barge refueling (this is referred to as the "No Barge Refill" disruption in Table 6 or "Disruption 6"); and 3) Loss of any oil refueling across NYCA (referred to as the "No Refill" disruption in Table 6 or "Disruption 7").

3. Restrictions on Natural Gas Availability for Electric Generation (Disruptions 8-10)

Possible disruptions to the natural gas supply available to electric generators are critical to model when analyzing the impact of extreme cold weather on system operations. For example, there could be physical breakages of compressor stations or pipelines that could limit natural gas deliveries. In order to model such contingencies in general, certain disruptive events were developed to represent the potential unavailability for non-firm natural gas to support electric generation: (1) throughout the entire NYCA (referred to as the "Non-Firm Gas Unavailable NYCA" disruption in Table 6 or "Disruption 8"); (2) limiting such unavailability to load zones F-K (referred to in Table 6 as the "Non-Firm Gas Unavailable F-K" disruption or "Disruption 9"); and (3) limiting non-firm gas available NYCA wide for only four days (referred to in Table 6 as the "Non-Firm Gas Unavailable 4 days" disruption or "Disruption 10"). Disruptions eight and nine are identical to the 2019 Fuel and Energy Security Study, while disruption ten was developed for this study to address shorter-term gas availability concerns that may not last for the entire model period, as noted in stakeholder discussions and in AG's review of relevant cold weather analysis literature.

4. Combination of Disruptive Events (Disruption 11)

The "Combination Disruption" referred to in Table 6 (also referred to as "Disruption 11") represents circumstances where multiple disruptive events (50% decrease in gas availability NYCA-wide, 50% increase lead time for oil refill, and loss of SENY generation [i.e., Disruption 3]) occur simultaneously. Relative to the "Extreme Disruption" modeled in the 2019 FESA that was designed to maximize the stress on the modeled electrical system (i.e., simultaneous occurrence of Disruptions 3, 7 and 8), the combined disruption event for this 2023 study is designed to be a slightly less severe, and potentially more probable confluence of events to stress the system across multiple dimensions simultaneously.

Table 6: Disruptions

Disruption Name	Description
1. Starting Conditions	No physical disruptions
2. High Outage	Double unit forced outage rate compared to historical averages
3. SENY Deactivation	Loss of significant capability (1,000 MW) in SENY (specifically, load zones G-I)
4. Nuclear Station Outage	Loss of major nuclear facility upstate (i.e., Nine Mile Point 1 and 2)
5. No Truck Refill	Unavailability of truck oil fuel delivery based on historical events such as snow storms
6. No Barge Refill	Unavailability of barge oil fuel delivery based on historical events such as NYC rivers freezing
7. No Refill	Unavailability of any oil fuel delivery due to severe fuel limitations affecting both barge and truck refueling
8. Non-Firm Gas Unavailable F-K	No non-firm gas-fired generation capability available in load zones F-K
9. Non-Firm Gas Unavailable NYCA	No non-firm gas-fired generation capability available anywhere in NYCA
10. Non-Firm Gas Unavailable 4 days	No non-firm gas-fired generation capability available anywhere in NYCA over the cold snap weekend, model days 6-9
11. Combination Disruption	50% firm gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2

C. Modeling of Scenarios and Disruptions

Finally, to test the joint impact of system condition differences and disruptive events, all combinations of the primary scenarios and disruptions were modeled for each winter period. As described above, in winter 2023/2024, these combinations apply to scenarios one through four, while winters 2026/2027 and 2030/2031 include all eight scenarios. These model runs are referred to as "cases." These cases run the gamut from mild to extreme stresses on the electrical system. The results of the analysis of these cases is presented in Section VI.

V. Output Metrics

A. Model Output

The fuel and energy security model is run for each case identified for analysis (as described in Section IV, each case is a combination of a scenario and disruption). The model proceeds through a stacking order/dispatch sequence based on the data inputs described above, including physical constraints on unit operations and the flow of power between locations within New York. Results are presented along several metrics indicating system reliability performance, including the identification of potential loss of load events. The results are assessed both individually for each case, and across all cases. In this section, the model output metrics and graphics are described, followed by the process used to distill case results into a set of reliability risk assessments.

For each model run, the fuel and energy security model estimates or tracks:

a. Natural gas demand and availability for power generation;
b. Hourly demand for electricity;
c. Hourly generation, fuel use, and stored fuel inventory by unit (battery storage energy output is reported when applicable);
d. Fuel of operation for dual-fuel units;
e. Periodic oil inventory replenishment based on inventory levels, use, and refill capabilities;
f. Total hourly zonal generation relative to electrical demand (including reserves);
g. Hourly capacity imports, energy-only exports to New England, and transfers of power between load zones;
h. Magnitude of actions taken to avoid the potential for a loss of load on an hourly basis, in each load zone, including reduction in energy-only exports to New England, activation of SCRs/EDRP, and reserve shortages (reserve shortages are measured against the modeled reserve requirements – see Section III.D.1); and
i. Magnitude of potential loss of load on an hourly basis, in each load zone, over the seventeen-day modeling period.

While the central focus of the model outputs are the magnitudes, duration and frequency of potential loss of load events, all of these metrics are considered. In order to assist in the detailed analysis of each case, and for comparison of potential loss of load event drivers across cases, the model generates a consistent set of tables and graphics for each case. For illustration of the reporting outputs on case outcomes, Figure 15 through Figure 23 present an example of the full set of metrics generated in graphical and tabular form for one case - namely the most severe case run for the upcoming winter 2023/2024 period, based on total loss of load over the duration of the 17-day modeling period (i.e., representing the case consisting of scenario 2 and disruption 9).[53]

[53] Figure 15 presents an overview of the hourly results graphically and includes simple hourly averages of the magnitudes of actions taken as measured over the entire duration of the 17-day cold weather event (i.e., 408 hours). The hourly magnitudes of the actions taken can be seen in the following figures.

Figure 15: Example of Hourly Results Summary

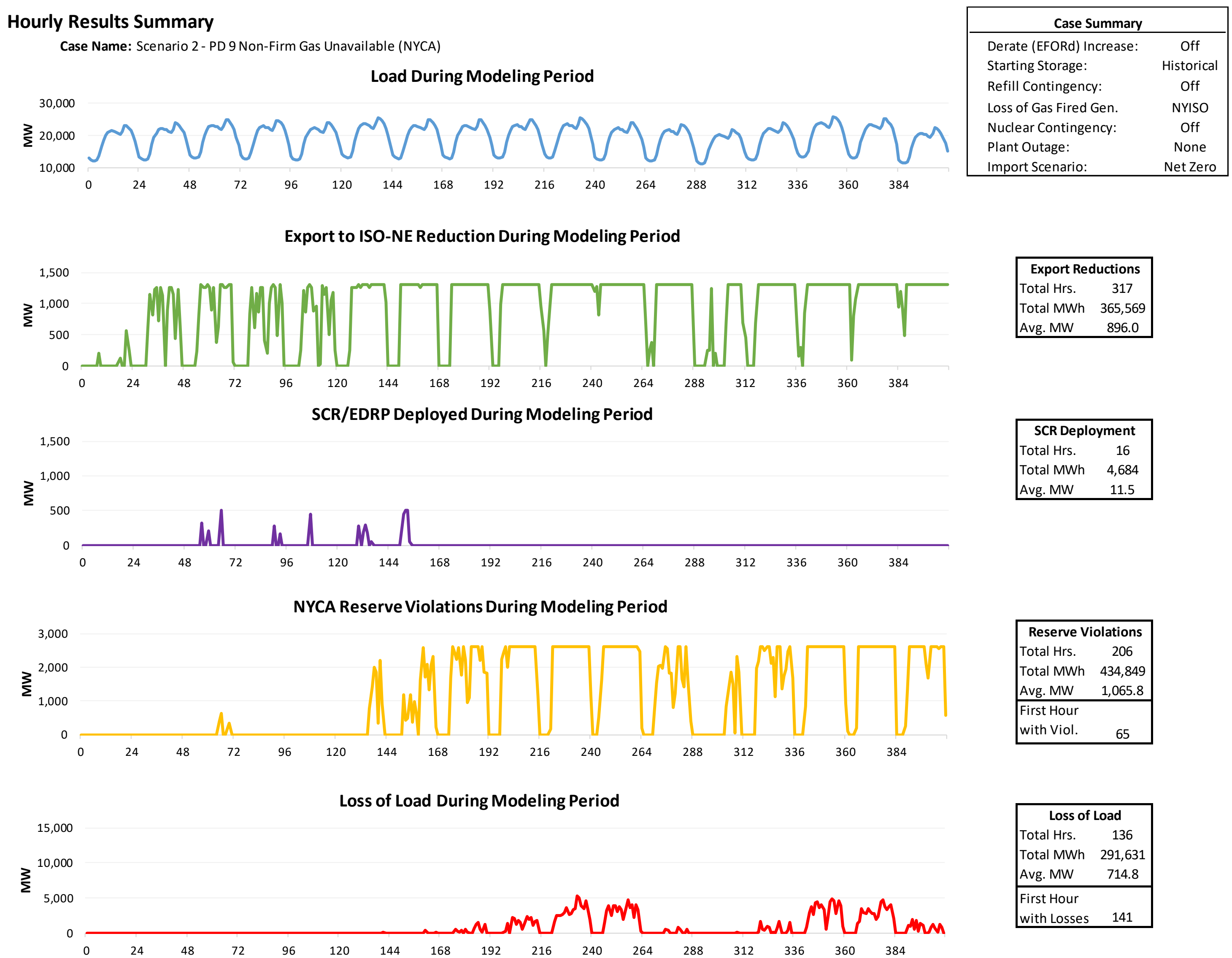


Figure 16: Example of Full Period Results Summary

Figure 17: Example of NYCA Hourly Generation by Fuel Group

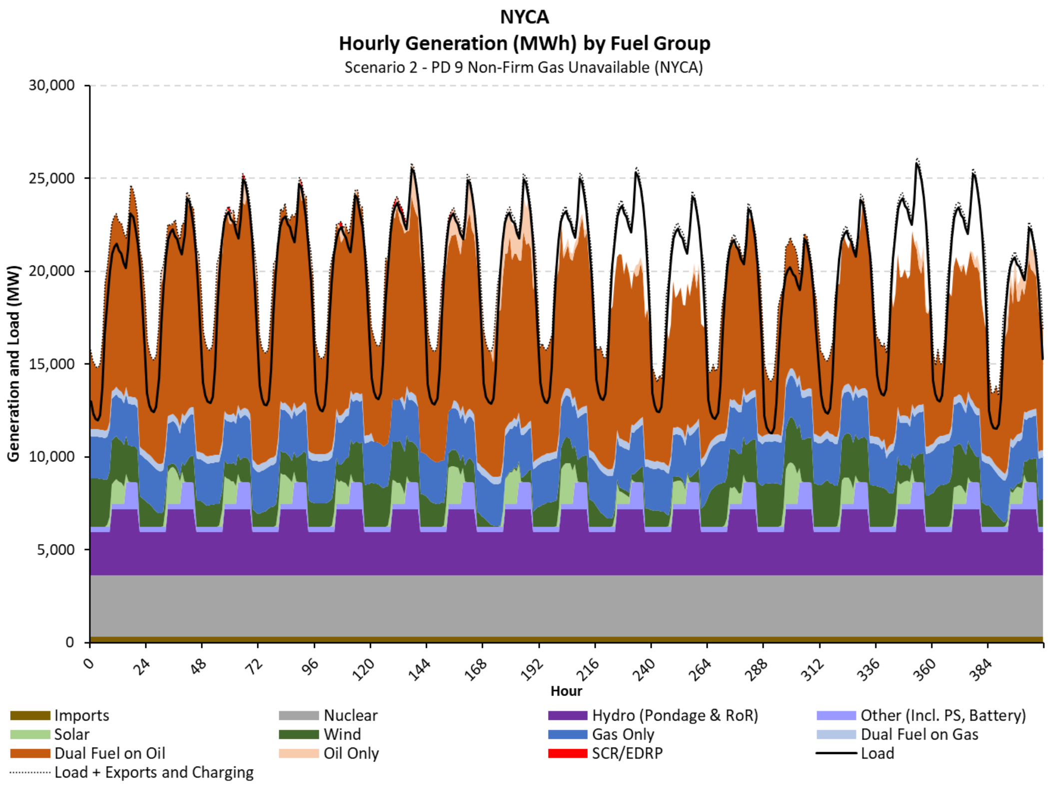


Figure 18: Example of Load Zone J Hourly Generation by Fuel Group

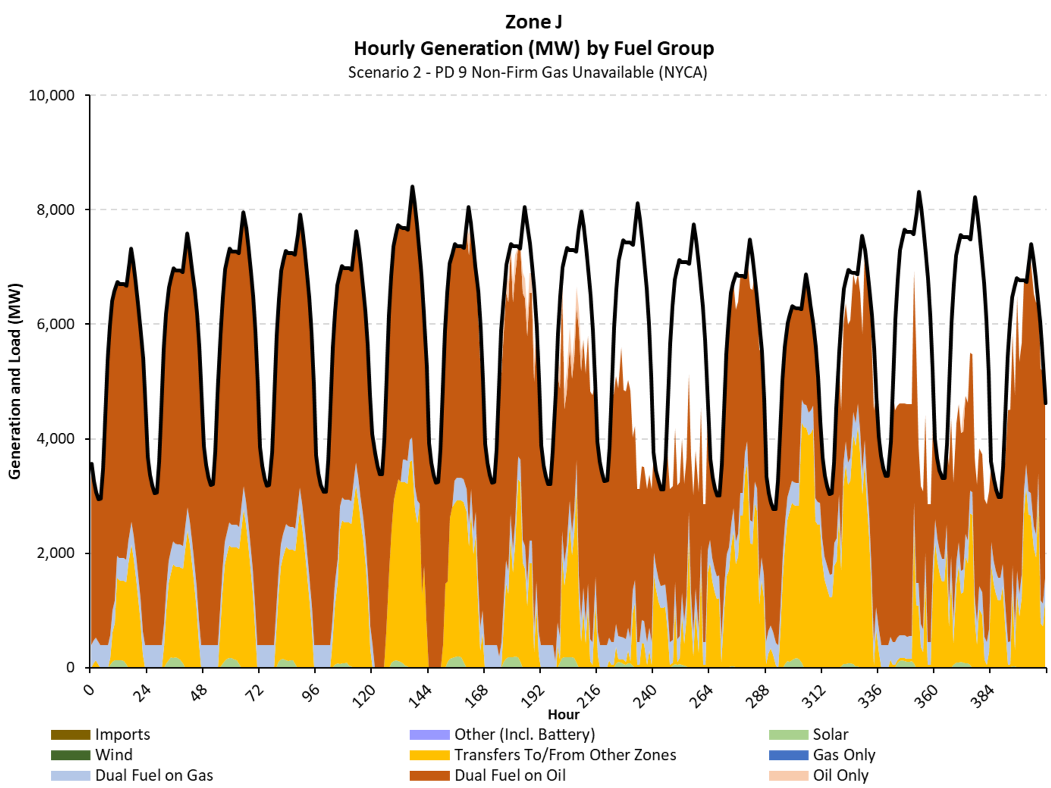


Figure 19: Example of Load Zone K Hourly Generation by Fuel Group

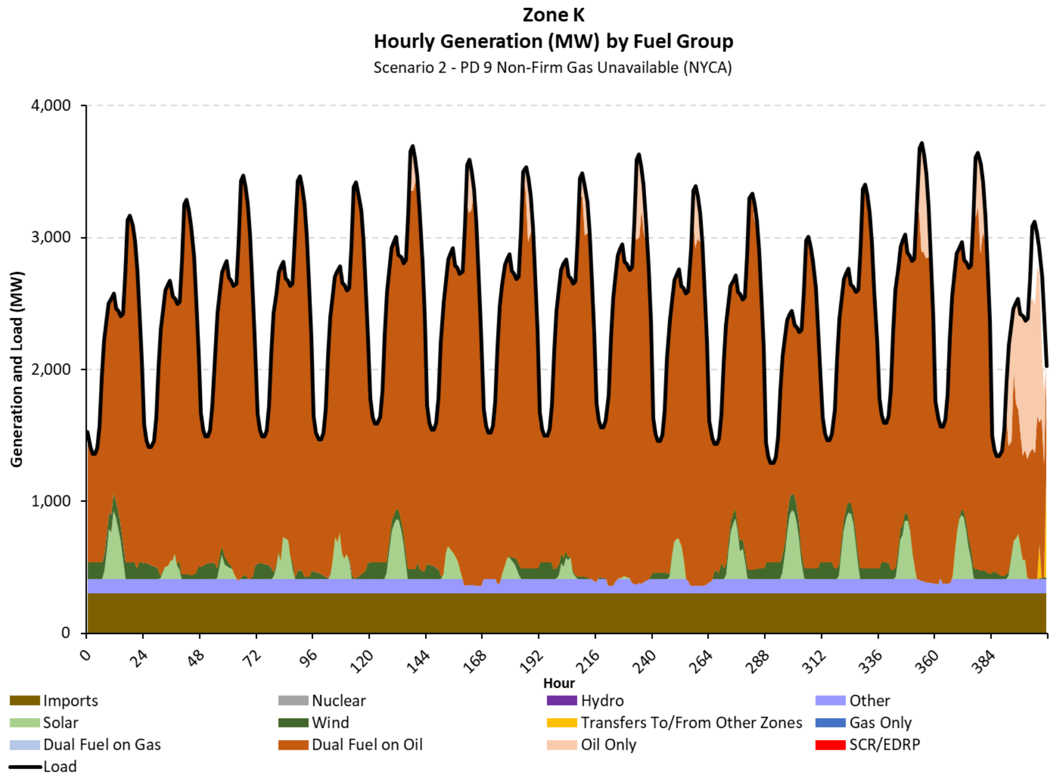


Figure 20: Example of NYCA Fuel Inventory

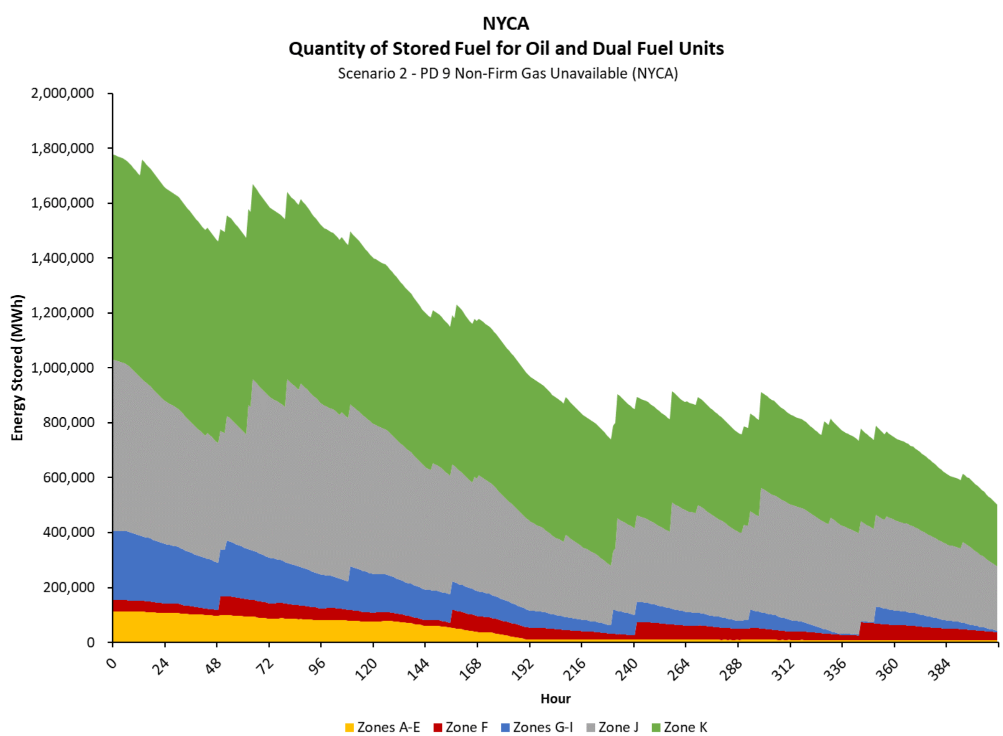
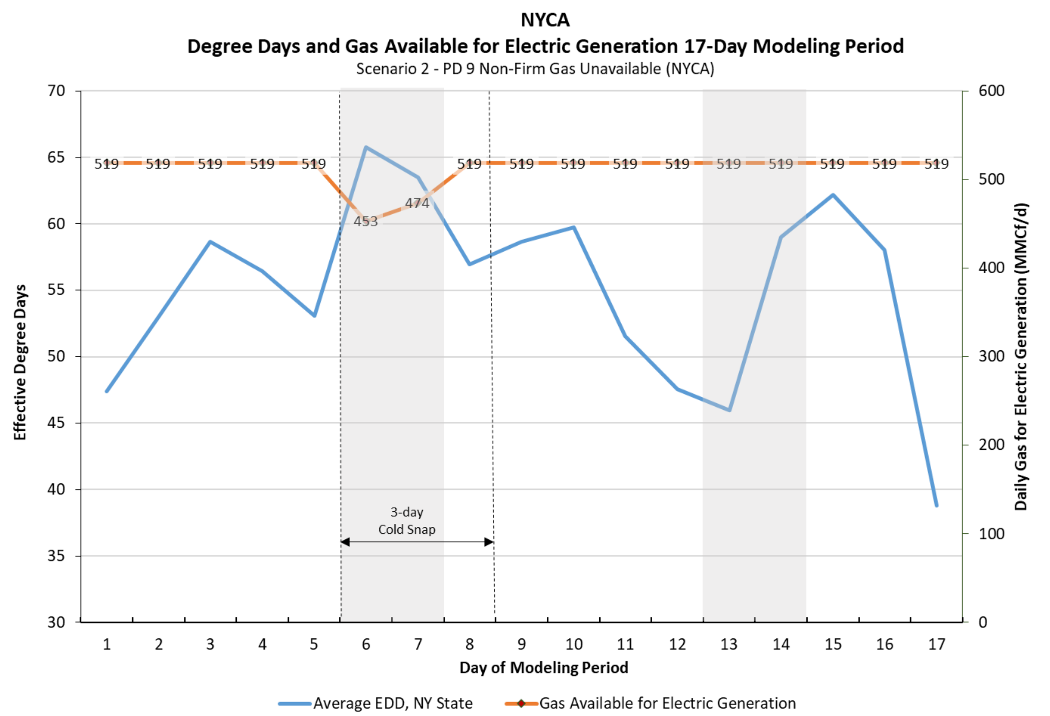


Figure 21: Example of NYCA Weather and Gas Available for Generation



Notes:
[1] Weekends are shaded in gray.
[2] Effective degree day is defined as 65 degrees F - Temperature.

Figure 22: Example of NYCA Emergency Actions and Potential for Loss of Load Summary

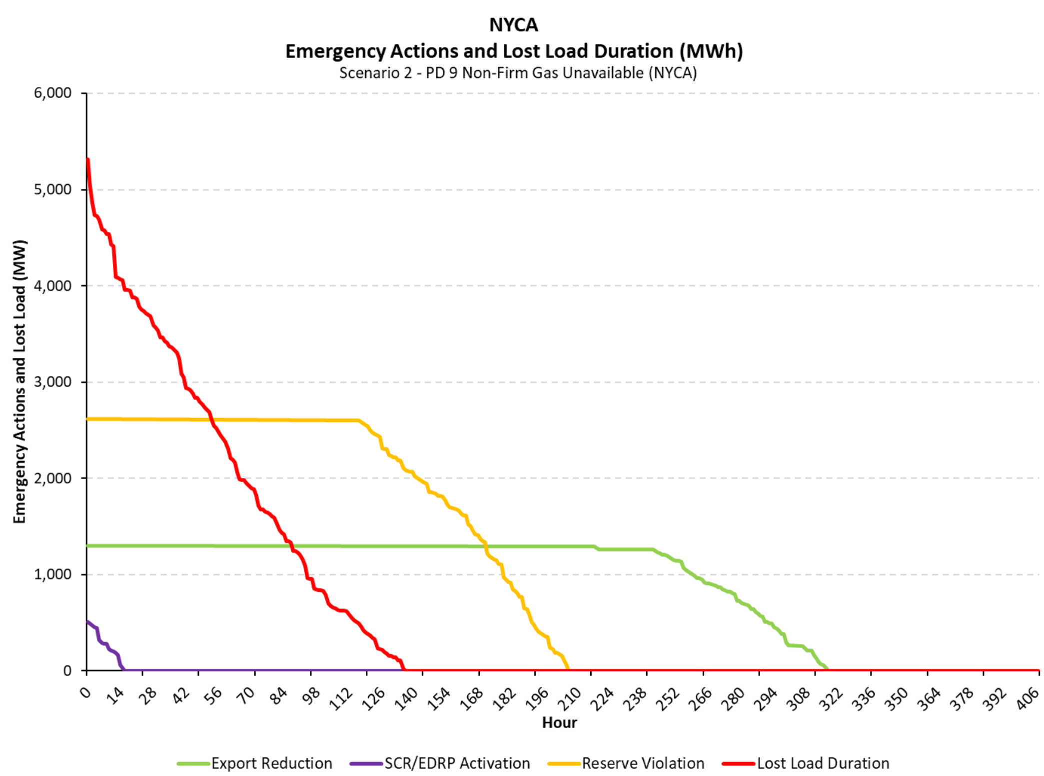
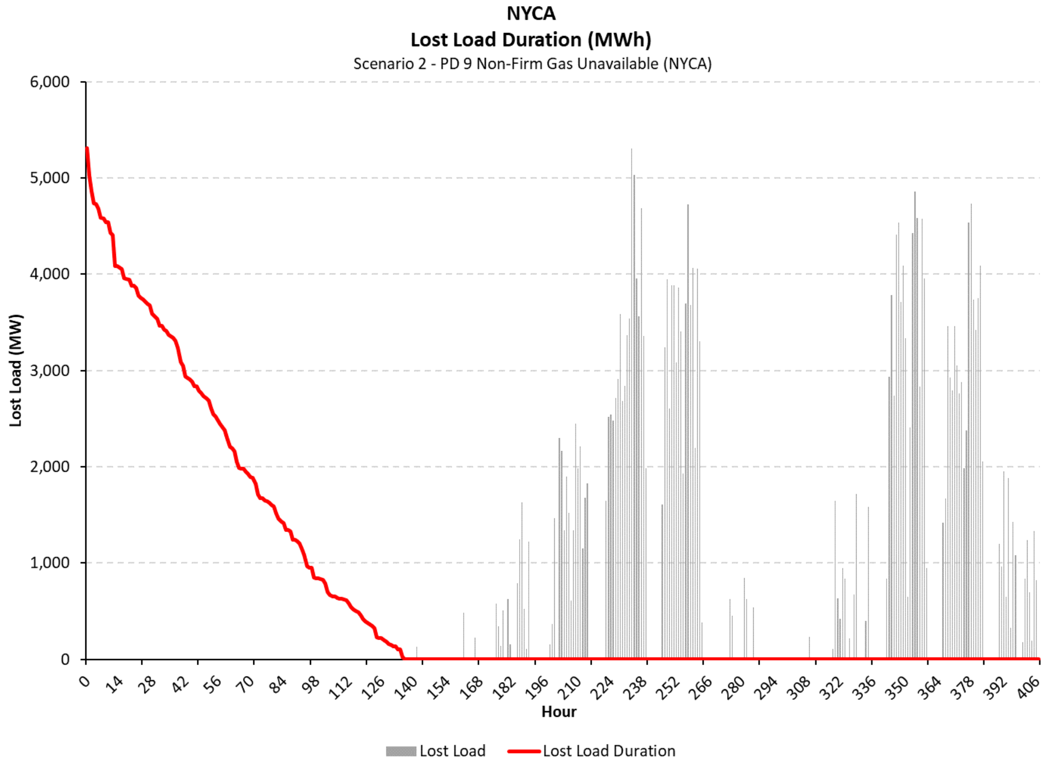


Figure 23: Example of NYCA Potential Lost Load Duration



B. Consideration of Case Probabilities for Winter 2023/2024

A key focus of the analysis is on cases where there is potential loss of load event, or where leading indicators (energy-only export reductions, SCR/EDRP activations, and/or reserve shortages) point to tight conditions and heighted reliability risks. Each case is reviewed and analyzed based on case conditions (generating resource availability, weather, unit additions/retirements) and the more dynamic factors that tend to most strongly influence system operations under cold weather conditions – including, for example, available natural gas (for power generation), initial fuel inventories, the drawing down of fuel inventories, and the ability and pace of inventory replenishment. Cases are analyzed based on number of hours with required NYISO actions (reduction of energy-only exports to New England and/or SCR/EDRP activations), hours with reserve violations after NYISO actions, and hours with potential load deficits after NYISO actions and reserve requirement violations. In addition, the severity of impact, meaning the magnitude, duration, and frequency of any identified reserve and/or potential load deficits, was also analyzed. In this first level of analysis, any case that leads to a potential loss of load event of any magnitude or duration is flagged for further review.

However, the model itself does not take into account other emergency actions such as voltage reduction, public appeals, or targeted load shedding, nor does it automatically consider that there may be other steps that could be taken to resolve any transient or minor potential outage (e.g., allowing assets to move to emergency operation ratings). In addition, the model does not take into account the probability that the combination of scenario definition and the disruptions identified in a particular case will come to fruition. In other words, the model output metrics quantify the potential reliability *consequences* of each case – that is, the magnitude and duration of potential loss of load events (or for leading indicators) under severe weather conditions and the postulated combinations of system scenarios and disruptions. Yet this is not a complete representation of the potential "risk" to the system.

"Risk" can be thought of as the product or combination of consequence and *probability*, or likelihood of occurrence. The probability of experiencing circumstances postulated for a given case can vary significantly. For example, some of the cases reviewed could involve system conditions that lead to severe potential loss of load events, yet are highly unlikely to occur and, thus, represent small operational risk. On the other hand, certain cases may be more plausible, yet represent consequences that are easily remedied (e.g., by the activation SCRs/EDRP or other actions not modeled in the analysis) or otherwise do not present meaningful concerns or risk. Therefore, it is helpful when thinking about the implications of the analytic results to consider metrics of both probability and consequence.

Consequently, in addition to analysis of the model's output metrics, the first case year (i.e., the 2023/2024 winter period) was categorized with respect to the degree of likelihood associated with the case conditions occurring. While this is necessarily a somewhat subjective exercise, the assessment is informed by the types of system conditions and circumstances generally used in power system operational studies. In other words, the system conditions presented by each case were assessed relative to the conditions imposed in other system operational analyses (e.g. a summer operational analysis that involves severe heat, the loss of generating capacity, and loss of a major transmission line).

Importantly, this analysis is not intended to replicate a probabilistic assessment of whether the conditions in question will or will not meet a standard such as loss of load no more frequent than once in ten years.[54] That type of assessment is not within the scope of this report. However, the relative likelihood of each case was qualitatively evaluated with an eye towards how the conditions might stack up against those imposed in other operational analyses. If conditions are far less likely than those typically considered, the case is given less weight. If similar or as likely, more weight is assigned to such a case.

The purpose of combining assessments of both probability and consequence in this way is to focus in on the subset of cases that (a) have the potential for significant reliability risks, and (b) are probable enough to merit further attention and consideration of whether mitigating action is warranted. While this process necessarily involves the application of judgment and the use of assumed metrics of impact, the transparent nature of the analysis and comprehensive set of diagnostics allows entities to develop their own interpretation of results, to the extent they differ from those contained herein.

Specifically, for winter 2023/2024, an additional heat map is created in which cases are color coded based on their level of risk, taking into account both the severity of potential loss of load impacts and an assessment of the likelihood of the conditions postulated in each case coming to fruition. With respect to the color coding, each case is categorized as follows:

- **White:** The case leads to few or no potential loss of load events, and none greater than 100 MW, and/or the probability of the combined scenario/disruption being realized is *extremely low, well outside* the types of system conditions and contingencies typically considered in operational assessments.
- **Yellow**: The case leads to potential loss of load events greater than 100 MW but none greater than 1,500 MW with such events generally being of moderate duration or frequency, and the probability of the combined scenario/disruption being realized is *low* or *on the order of* (or similar to) the types of system conditions and contingencies typically considered in operational assessments.[55]
- **Orange**: The case leads to potential loss of load events greater than 1,500 MW, but the probability of the combined scenario/ disruption being realized is *low, likely less probable* than the types of system conditions and contingencies typically considered in operational assessments.
- **Red**: The case leads to potential loss of load events greater than 1,500 MW, and the probability of the combined scenario/disruption being realized is *on the order of* (or similar to) the types of system conditions and contingencies typically considered in operational assessments.

The analysis of cases is summarized in Section VI below, and Appendix D provides detailed exhibits that show the results – in the form of potential loss of load duration curves – across all scenarios and all disruptions. "Heat maps" that cover results across all cases are also provided.

[54] NYISO is obligated to plan for a system that has the "probability (or risk) of disconnecting any firm load due to resource deficiencies [...], on average, not more than once in ten years." New York State Reliability Council, "Reliability Rules and Compliance Manual," February 9, 2018, p. 13, available at https://www.nysrc.org/wp-content/uploads/2023/03/RRC-Manual-V42_Final.pdf.

[55] The yellow color code has been updated relative to the 2019 FESA to reflect recent winter events that are now more probable under system conditions and contingencies akin to those typically considered in operational assessments and that could result in moderate loss of load events.

VI. Results and Observations

1. Results

As described previously, the analysis begins with a supply and demand snapshot of the winters 2023/2024, 2026/2027 and 2030/2031 subject to severe winter conditions over the seventeen-day cold-weather modeling period. Over these winter periods, the system is depicted through various combinations of system scenarios and disruptions, representing over two hundred cases in aggregate. Each case is run through the fuel and energy security model, which generates a detailed set of case diagnostics.[56]

The key results for each case are depicted in Figure 24 to Figure 26. These figures represent the occurrence of potential hourly loss of load events across the seventeen-day modeling period as a line chart within each case box, showing the relative magnitude, frequency, and duration of potential loss of load events for each case. No line within the box indicates no potential loss of load event associated with the case at issue. The most significant potential loss of load events are seen in cases involving disruptions to oil supply, gas supply, or combinations of disruption events.

For winters 2023/2024 and 2026/2027, the cases are also categorized with respect to magnitude and probability of impact. Specifically, in Figure 27 and Figure 28, cases are color coded based on their level of risk, taking into account both the severity of potential loss of load event impacts and an assessment of the likelihood of the conditions postulated in each case coming to fruition. With respect to the color coding, each case is categorized as follows:

- **White:** The case leads to few or no potential loss of load events, and none greater than 100 MW, and/or the probability of the combined scenario/disruption being realized is *extremely low, well outside* the types of system conditions and contingencies typically considered in operational assessments.
- **Yellow**: The case leads to potential loss of load events greater than 100 MW but none greater than 1,500 MW with such events generally being of moderate duration or frequency , and the probability of the combined scenario/disruption being realized is *low* or *on the order of* (or similar to) the types of system conditions and contingencies typically considered in operational assessments.[57]
- **Orange**: The case leads to potential loss of load events greater than 1,500 MW, but the probability of the combined scenario/disruption being realized is *low, likely less probable* than the types of system conditions and contingencies typically considered in operational assessments.
- **Red**: The case leads to potential loss of load events greater than 1,500 MW, and the probability of the combined scenario/disruption being realized is *on the order of* (or similar to) the types of system conditions and contingencies typically considered in operational assessments.

The purpose of combining assessments of both probability and consequence in this way is to focus in on a subset of cases that (a) have the potential for significant reliability risks, and (b) are probable enough to merit further attention and consideration of whether additional mitigating action is warranted (e.g., enhancements to operational procedures and/or market designs). While this process necessarily involves the application of

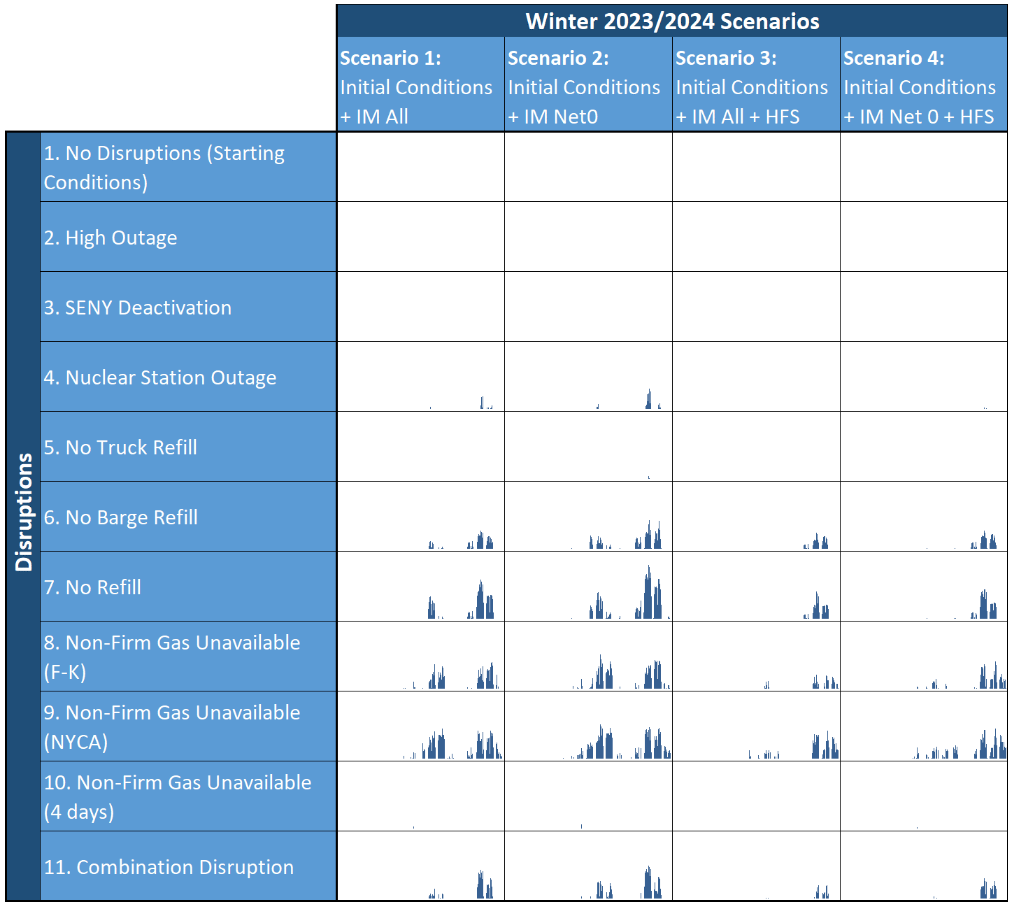
[56] The detailed results across all cases are further described in [[Section VI]], with the detailed diagnostics for each case presented in [[Appendix E]].

[57] The yellow color code has been updated relative to the 2019 FESA to reflect recent winter events that are now more probable under system conditions and contingencies akin to those typically considered in operational assessments and that could result in moderate loss of load events.

professional judgment and the use of assumed metrics of impact, the transparent nature of the analysis and comprehensive set of diagnostics allows entities to develop their own interpretation of results, to the extent they differ from those contained herein.

It is useful to observe the results across modeled disruptions for a given scenario, and *vice versa*. In this way it is possible to see the specific impact of a given set of system conditions or disruptive event on reliability risks, or to gauge the magnitude of impact from one case to another, all else equal. For example, in all three winters modeled, scenario 1 contains a cross section of results that vary in probability and impact across the assumed disruptions. Figure 29 to Figure 31 show for each winter how both the severity of potential loss of load events (in MW, the y -axis) and duration across the 17-day cold weather event period (in hours, the x- axis) vary as the scenario progresses from an assumption of no disruptions through the various assumed disruption events. A full set of potential loss of load duration curves for each winter by both scenario and disruption are included in Appendix D.

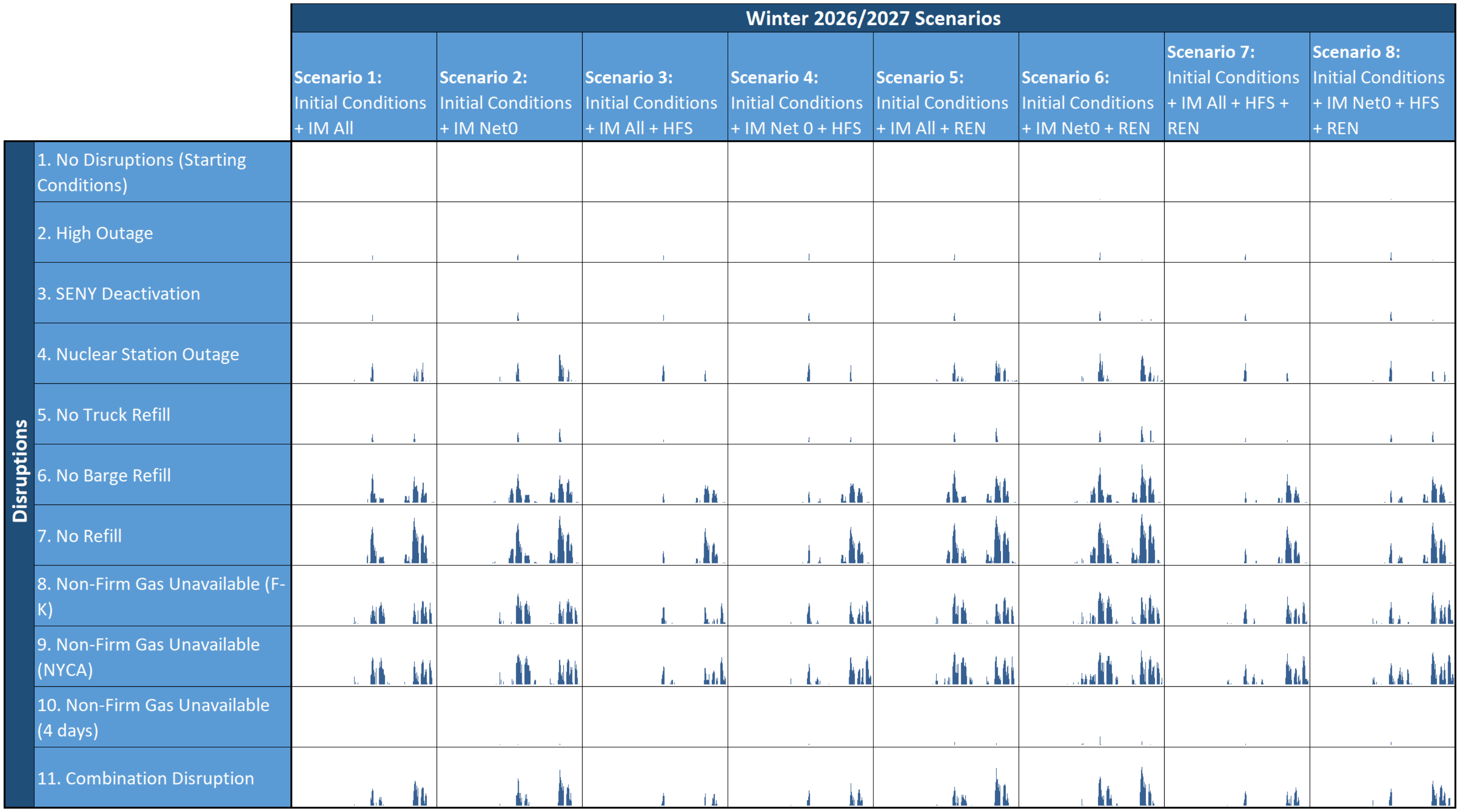
Figure 24: Potential Loss of Load Events by Case, Winter 2023/2024



Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

<u>**Scenario Key**</u>
IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

Figure 25: Potential Loss of Load Events by Case, Winter 2026/2027

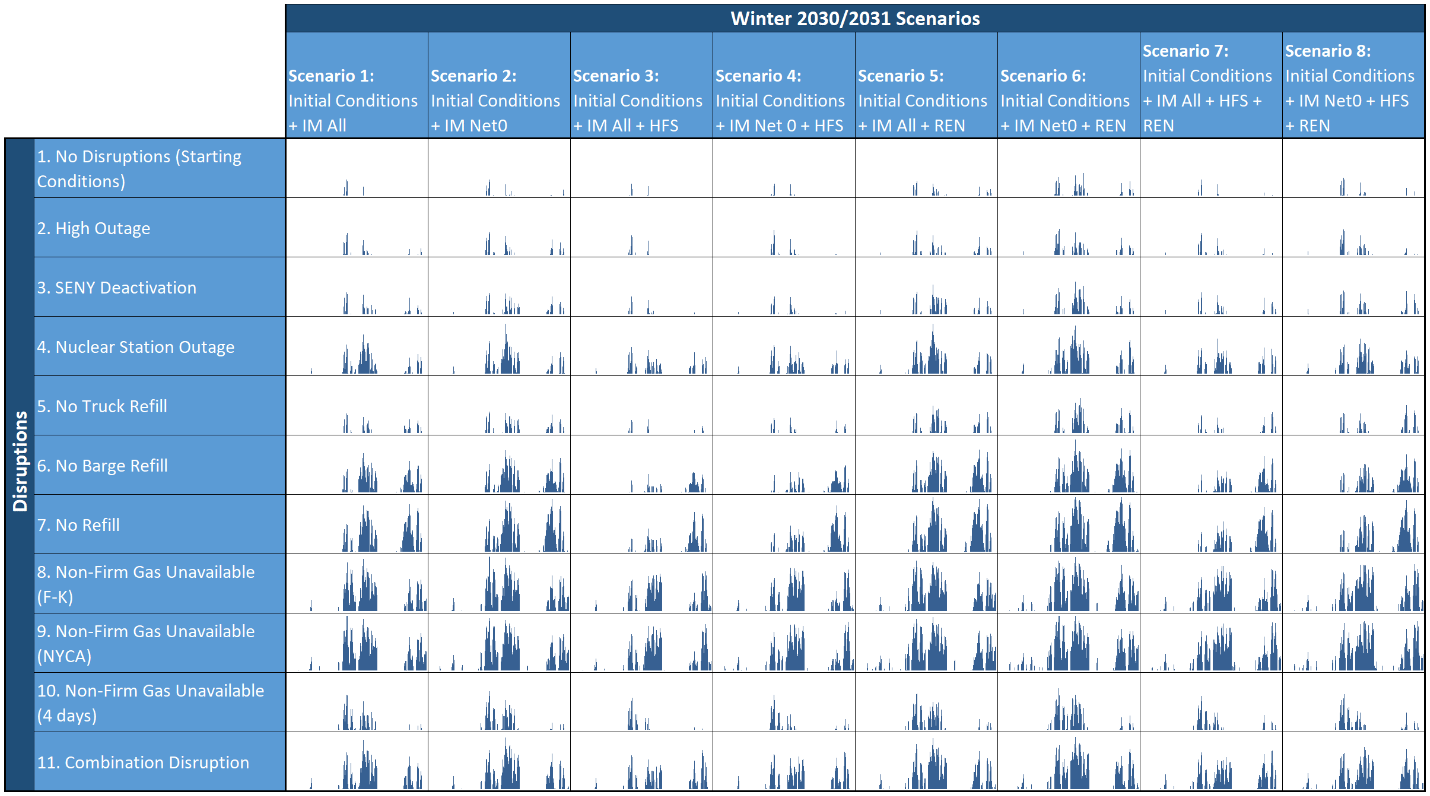


Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

Scenario Key

IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
REN = 33% decrease of utility solar and land-based wind capacity 2021-2040 Outlook Contract Case additions.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

Figure 26: Potential Loss of Load Events by Case, Winter 2030/2031[58]



Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

Scenario Key

IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
REN = 20% decrease of utility solar, land-based wind, and offshore wind capacity 2021-2040 Outlook Policy Case 1 additions.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

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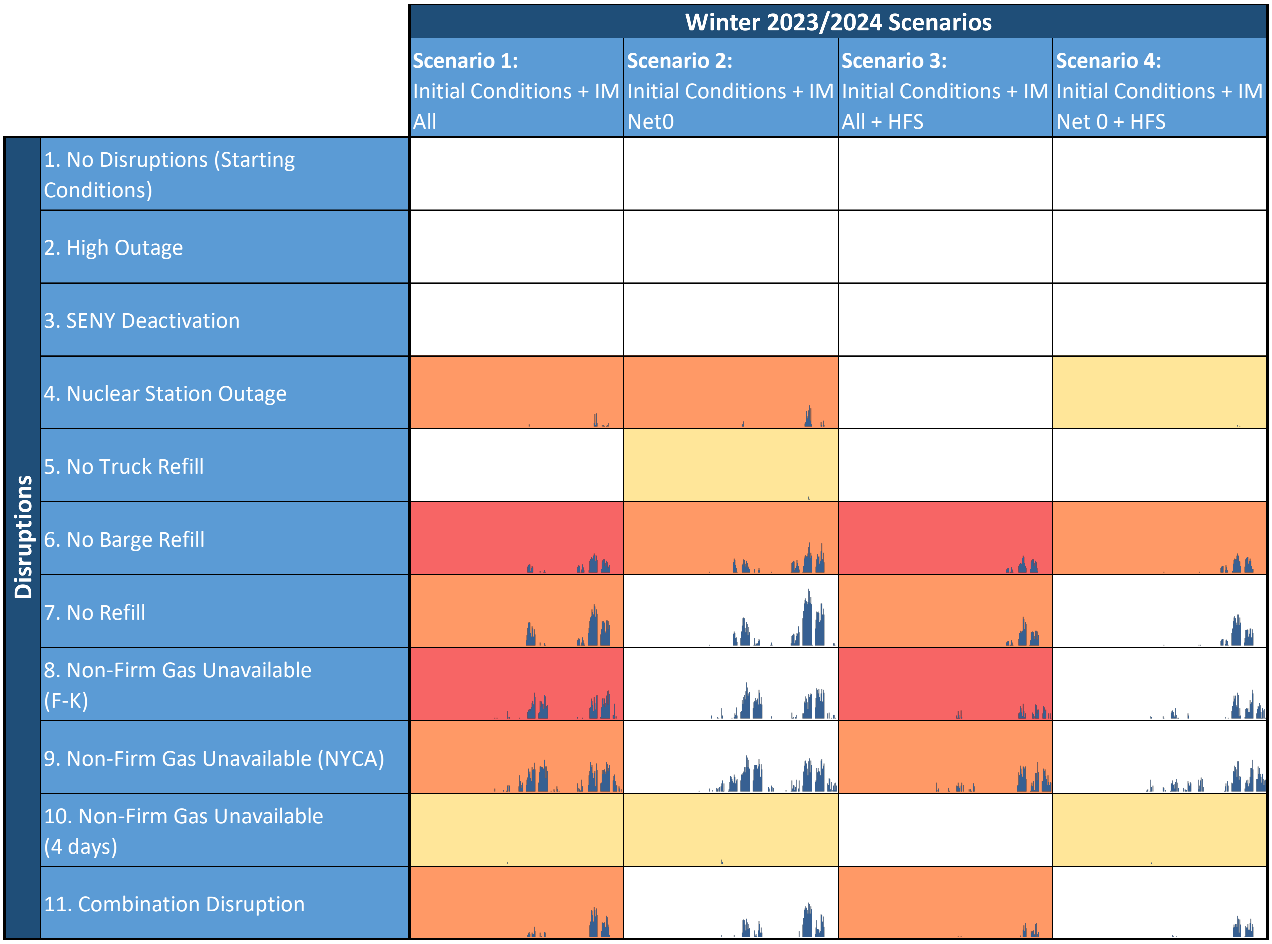
[58] In the winter 2030/2031 only, there are instances where potential loss of load exceeds 10,000 MW in a given hour. The following five cases exhibit potential maximum hourly potential loss of load events that exceed 10,000 MW, ranging from a magnitude of10,000 MW to 11,500 MW: Scenario 1 – PD 9, Scenario 2 – PD 8, Scenario 5 – PD 7, Scenario 6 – PD 7, Scenario 6 – PD 9.

Figure 27: Heat Map of Potential Reliability Risks, Winter 2023/2024



Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

- Consequence 0-100 MW or probability extremely low (far outside normal operational assessments)
- Consequence 100 - 1,500 MW, of moderate duration/frequency, and probability low or on the order of normal operational assessments
- Consequence greater than 1,500 MW, and probability low (meaningfully less likely than normal operational assessments)
- Consequence greater than 1,500 MW, and probability on the order of normal operational assessments

Scenario Key

IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

Figure 28: Heat Map of Potential Reliability Risks, Winter 2026/2027

Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

- Consequence 0-100 MW or probability extremely low (far outside normal operational assessments)
- Consequence 100 - 1,500 MW, of moderate duration/frequency, and probability low or on the order of normal operational assessments
- Consequence greater than 1,500 MW, and probability low (meaningfully less likely than normal operational assessments)
- Consequence greater than 1,500 MW, and probability on the order of normal operational assessments

<u>Scenario Key</u>

IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
REN = 33% decrease of utility solar and land-based wind capacity 2021-2040 Outlook Contract Case additions.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

Figure 29: Loss of Load Duration Curves for Scenario 1, All Disruptions, Winter 2023/2024

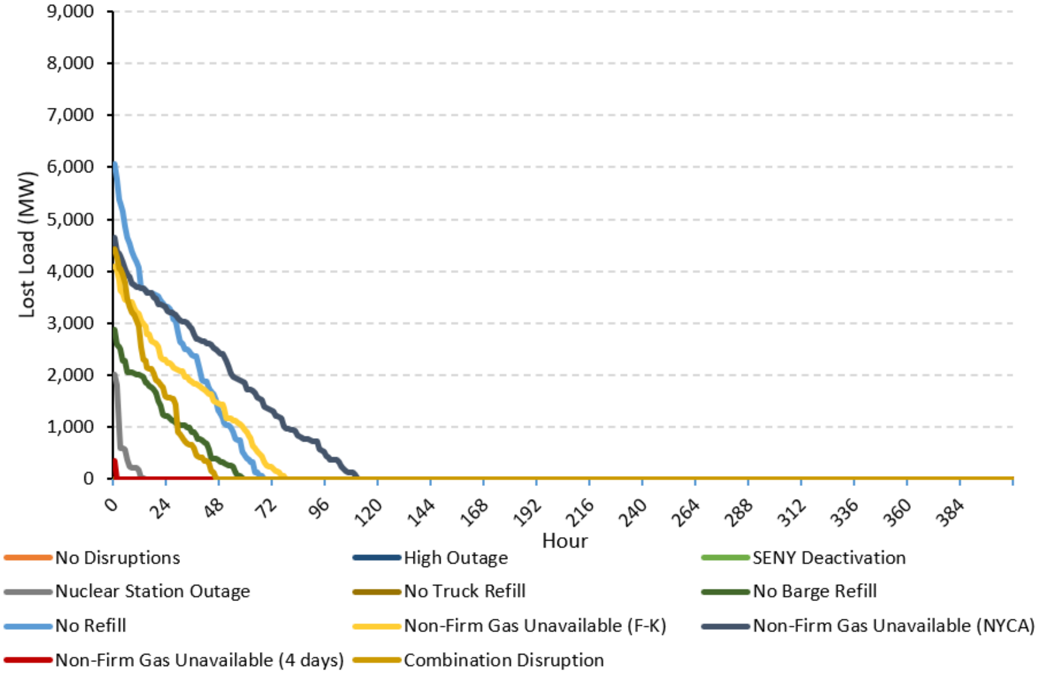


Figure 30: Loss of Load Duration Curves for Scenario 1, All Disruptions, Winter 2026/2027

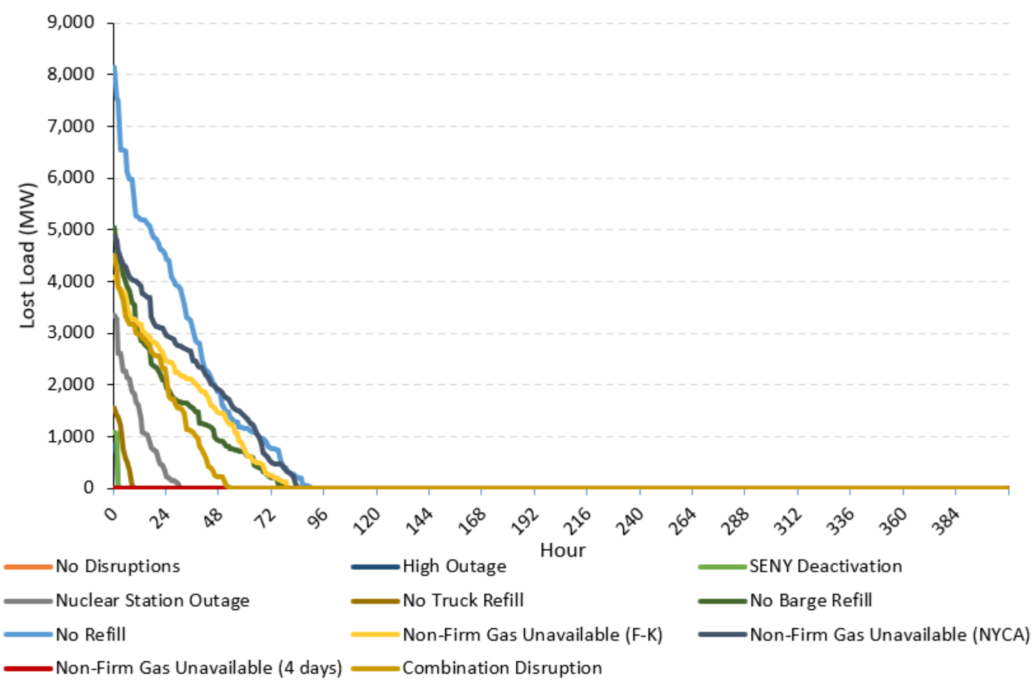
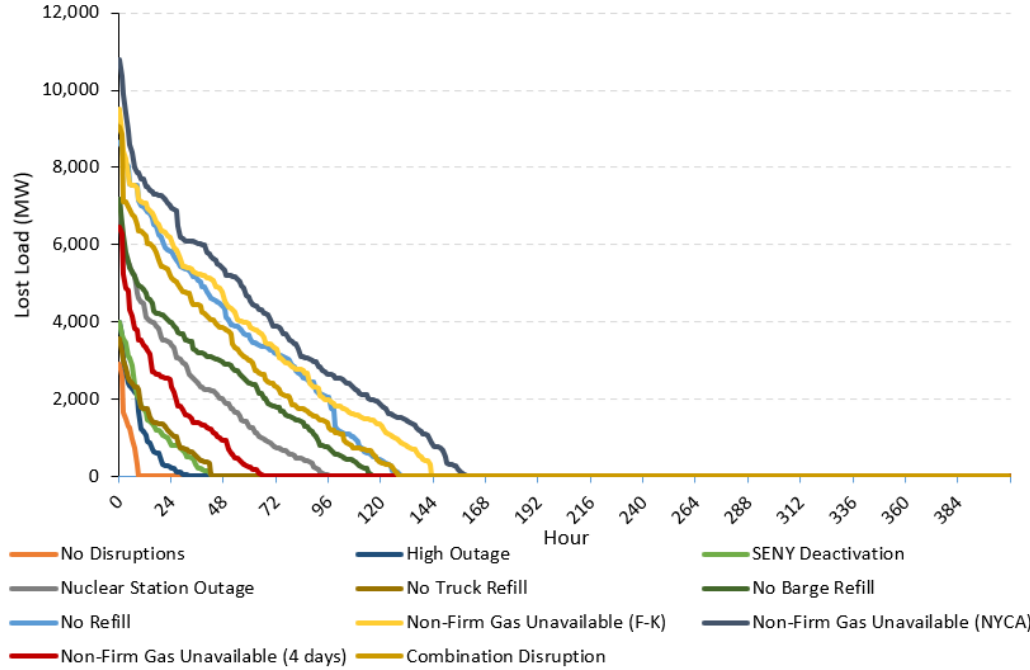


Figure 31: Loss of Load Duration Curves for Scenario 1, All Disruptions, Winter 2030/2031



2. Observations

Based upon the review of detailed case diagnostics, the following observations with respect to fuel and energy security in New York have been identified:

The modeling results show the potential for operational challenges and loss of load events across all three winters studied. The frequency and severity of projected potential loss of load events grow over the modeling time horizon. For the upcoming winter 2023/2024 period, fuel supply disruptions are the most prominent concern. In the future two winters modeled (i.e., 2026/2027 and 2030/2031), as the system resource mixture evolves, lulls in production from intermittent generation resources (particularly offshore wind) also become an important consideration. Finally, in 2030/2031 winter period, in which modeling input assumptions are subject to the greatest uncertainty, the results portend a growing frequency in operational challenges and potential for loss of load events across all assumed disruptions.

The availability of oil and gas generation resources is critical to alleviate potential loss of load events. The overall risk associated with disruptions to fuel and energy availability during winter months grows as the resource mixture changes and electricity demand increases to meet the state's decarbonization objectives. For the upcoming winter 2023/2024 period, the cases reviewed that *do not* involve significantly adverse assumptions about system configurations or major disruptive events, exhibit little or no risk to power system reliability. However, in the winter 2026/2027 period, the overall risk associated with less adverse disruptions rises. The winter 2030/2031 modeling results reinforce the results observed in the winter 2023/2024 and 2026/2027 analyses. The potential for loss of load events substantially increase for the winter 2030/2031 period, including in those instances with no assumed disruptions. The results underscore the scope of the NYISO's operational challenges that can result when fuel and energy supplies are disrupted/limited during the ongoing transition of the power system in response to the requirements of the CLCPA.

In comparison with the 2019 FESA, the results show that the NYISO power system has grown more sensitive to fuel disruptions in recent years. In particular, the following updated model inputs (relative to the 2019 FESA) drive the increase in the potential for system reliability risks: (1) the estimated gas available for electricity generation is reduced based on updated data and information from New York's LDCs; (2) fewer renewable and other clean energy resources have come online relative to the projections in 2019; (3) fossil unit retirements (especially peaking facilities downstate) proceeded at the fastest pace assumed in the 2019 FESA, and are included in all modelling scenarios; (4) certain generators have reported increased oil refill lead times and/or lower oil inventories to start the winter in the NYISO fuel surveys; and (5) energy imports from ISO-NE to Long Island are assumed in all cases. Collectively, the initial conditions for this updated study more closely resemble scenarios in the 2019 FESA that had more potential for loss of load events.

Higher starting oil tank inventory levels help alleviate operational challenges and potential loss of load events. As the generation mixture evolves and electricity demand increases during the ongoing transition to a decarbonized electric grid, the importance of ensuring that generation resources have sufficient oil storage during a multi-day cold weather period grows. The results of the analyses show that higher starting oil inventory levels and timely oil tank replenishment reduce potential loss of load events. For example, an assumed 50% increase in starting oil inventory levels resulted in an average decrease in modeled loss of load MWh of 58% for winter 2023/2024 cases, all else equal. Consideration of a 96-hour oil inventory requirement in certain ongoing market design initiatives helps ensure better preparedness for cold weather events. Ensuring oil inventories that allow for even longer than 96-hour operations where possible provides even greater fuel security during prolonged cold weather.

Significant interruptions in the availability of natural gas for power generation can introduce challenges for reliable operations. Disruptions involving the loss of (or reductions in) non-firm natural gas for power generation NYCA wide, or only in load zones F-K, lead to potential loss of load events under all scenarios.

Recent winter weather events reinforce the importance of ensuring that New York's power system will be able to operate reliably during extreme winter weather. The impacts of recent events, such as Winter storm Uri and Elliott revealed unexpected operational challenges for system operators. Large numbers of electric generation resources could not be operated because of both equipment failures and inability to obtain fuel supply. The presence of potential loss of load events in the modeling results show that severe winter weather conditions could have a similar effect in New York. Moreover, operational challenges in other regions during severe winter weather conditions could lead to decreased electric imports into New York, which the modeling results indicate would exacerbate the potential for loss of load events.

Significant potential for loss of load events appear in cases involving reduced operation of oil-fired generating assets, particularly in New York City. New York encounters meaningful reliability challenges when little natural gas is available and/or the ability to rely on stored fuel for energy (e.g. replenish oil supplies) is constrained by weather or other factors. In fact, the vast majority of potential loss of load events occur in cases subject to disruptions associated with lower initial fuel oil inventories at oil and dual fuel power plants (i.e., consistent with recent observations), and/or reductions in or elimination of oil refill capability. In these cases, potential loss of load events tend to arise later in the seventeen-day modeling period as inventories are used up and are unable to be replenished.

Dual fuel capability – with oil as a backup fuel to natural gas – is vital for maintaining reliability during the ongoing system transition. Taking into consideration the demand for natural gas by LDCs for serving retail needs, there simply is not enough gas available for power generation downstate under prolonged, severe cold winter conditions to ensure reliable operations, absent the ability of dual-fuel units to operate on alternative fuel options. While these resources may operate economically – and to the advantage of electricity consumers – most of the year on available non-firm supplies of natural gas, under severe cold weather conditions LDC retail gas demand and other firm natural gas transportation commitments (including for deliveries to neighboring regions) reduce available natural gas for power generation to levels below that needed for reliable system operations. Maintaining adequate firm fuel resources such as firm gas only units, dual fuel and other oil-fired operating capability is critical to reliable operations during adverse winter conditions, especially in the downstate region, during the ongoing transition of the power system.

A number of circumstances leading to potential loss of load events are observed for New York City. Many cases with potential loss of load events greater than 1,500 MW and probability of occurrence conceptually similar to normal operational assessments were observed in New York City. New York City's vulnerability stems primarily from a particular reliance on oil-fired capacity, energy transfers from upstate, and a growing reliance on offshore wind generation resources whose energy production can **be significantly reduced for long periods of time ("wind lulls")**. Maintaining dual fuel (and other oil-fired) operating capability throughout the ongoing transition toward a decarbonized grid, ensuring available imports from upstate, and accounting for offshore wind energy production intermittency, are critically important to reliable winter operations for New York City.

Upstate generation resource availability is critical to provide energy to New York City. Generation resource unavailability in southeastern New York and/or an extended nuclear station outage result in increased potential loss of load events. The NYISO's reliance on the availability of its existing generation resource mixture upstate – and the transmission to deliver it downstate – grows along with projected electricity demand growth in response to system changes in response to requirements of the CLCPA.

The NYISO continues to take many steps to address potential risks associated with fuel and energy security concerns. The NYISO monitors, evaluates, and prepares to address potential risks associated with the availability of fuel and performance of generating assets. This includes a variety of practices and requirements intended to ensure continuous monitoring of assets and fuel inventories, and visibility into the operations, capacities and constraints of interstate pipelines and local natural gas LDC systems; relative coordination of the timing of natural gas and electricity markets and the ability of generators to account for fuel opportunity costs in offers; the existence of requirements on certain downstate generators related to the capacity to operate on multiple fuels and switching fuels if and as needed based on prevailing temperature conditions; the incorporation of dual-fuel requirements for peaking plant technologies in the setting of the ICAP Demand Curves for downstate capacity regions (load zones G-K); and the establishment of reserve requirements statewide and downstate to reflect locational reserve needs. The set of steps already taken through changes in market rules and/or operating procedures have the effect of both increasing situational awareness of the risks and instituting requirements and incentives supporting the availability of fuel and the operation of assets important for reliable winter operations.

The state's renewable and clean energy resources can provide valuable reliability support. While the potential reliability challenges associated with wind lulls are significant and increase as the state's dependence on weather-dependent resources (especially offshore wind in the downstate region) increases, these resources can also support reliable operations over the modeled winter period by reducing the drawdown of oil inventories. The injection of a large quantity of offshore wind energy directly into New York City and Long Island at times throughout the modeled seventeen day cold weather event helps preserve limited oil and natural gas for supporting reliable operations later in the modeled severe cold weather period. Similarly, a review of certain cases with limited magnitude and duration of potential loss of load events could be eliminated through the operation of additional energy storage capacity in targeted locations.

Over the longer term, the projected magnitude and pace of change to the resource fleet stemming from requirements under the CLCPA grows in importance. The fundamental changes envisioned by the CLCPA suggest that the power system will play a critical role in decarbonization of the state's economy, with at least two fundamental shifts that will affect fuel and energy security during winter months. The first involves the potential electrification of transportation, heating and other sectors to achieve the required GHG reductions in those sectors at the lowest possible cost to consumers. This is projected to significantly increase and change the demand for electricity within New York State, and particularly in the downstate load centers that the analysis demonstrates may be most susceptible to winter energy security risks. The second is the contemporaneous decarbonization of the electric sector itself – requiring that 70 percent of all electricity be met through renewable generation within roughly ten years (by 2030), and that all electricity be provided by zero emissions resources within approximately twenty years (by 2040).

The potential for rapidly expanding demand for electricity combined with dramatic reductions in fossil-fired generation – including presumably the oil- and gas-fired generation that is currently critical for winter system reliability in the downstate region – warrants careful consideration around how to manage this transition from the perspective of reliable winter operations.

The results of this fuel and energy security assessment reinforce the importance of the NYISO's continued evaluation, monitoring, and preparedness for the possibility of fuel and generation resource unavailability over a prolonged period of cold winter weather. The NYISO's ongoing assessments of fuel and energy security risk are critical to plan and prepare for system operations during prolonged cold weather events. The purpose of this report is not to point to a specific set of recommended actions based on the fuel and energy security analysis described in this report. However, the results of the modeling analyses demonstrate the critical importance of continued and careful monitoring of the evolution of supply and demand conditions and how these changes may complicate system operations during multi-day cold snap conditions. Moreover, with the potential for growing electricity demand in the state, in part due to electrification of the vehicle and building sectors, there will be increased importance in planning to reduce the risk of potential disruptions in fuel and energy supply.

3. Options

There is a wide range of potential options to consider that flow from the results of the analysis and the key conditions driving circumstances that lead to potential loss of load events, the experience with winter fuel and energy security efforts in other regions (e.g., ISO-NE and PJM), and the specific circumstances in New York. Potential options include:

Continued monitoring and analysis. The impact of severe winter conditions on power system operations in New York is highly dependent not only on the availability of fuel for generating resources, but on the portfolio of resources available, transmission capability to accommodate transfers throughout the state, the level and shape of demand under winter peaks, and the various disruptions or contingencies that may occur during cold weather conditions. Continued monitoring of these conditions represents a clearly valuable endeavor for reliable system operations. The NYISO and its stakeholders should ensure that system and resource planning efforts continue to account for the possibility of disruptive events on both the electric and gas systems and the possibility of winter fuel and energy security-related reliability challenges. For example, the reliance in New York on the flexibility afforded by dual fuel capability, particularly downstate, suggests continued or expanded vigilance in monitoring the practices of generating asset owners with respect to establishing initial winter fuel oil inventories and executing pre-season or in-season contracts with fuel oil suppliers for the reliable delivery (by barge and/or truck) of replenishment fuel on regular and as-needed bases. Moreover, a key uncertainty in the analysis is the actual expected availability of natural gas to support power generation under severe cold weather conditions. The NYISO should continue to interact with generation operators, interstate pipeline operators and the state's natural gas LDCs, and conduct analysis based on available data, to maintain an up-to-date understanding of the changing circumstances of natural gas infrastructure, LDC demand, and likely contractual flows out to neighboring regions.

Assessment of the adequacy of incentives for appropriate pre-season fuel oil inventory levels and/or replenishment arrangements. The current operational capability of oil-fired capacity downstate is critical to winter power system reliability in New York. The NYISO already monitors inventories, use and replenishment for these units. Moreover, certain units in the downstate region are subject to mandatory oil-burn operations under specified temperature and/or gas system conditions. Nevertheless, given oil's importance throughout the ongoing transition of the grid toward a carbon free system, if the continued monitoring of fuel availability identifies reductions in inventory levels and/or delays in replenishment in the future that may pose reliability risks to winter operations, the NYISO and its stakeholders may want to evaluate the adequacy of current incentives for establishing appropriate pre-season inventory levels and replenishment contracting arrangements. Appropriate signals for asset owners to have sufficient fuel to support continued operations throughout an extended period of cold-weather conditions are important for managing reliability risks.

Review of the potential for geographically-targeted development of new renewable and energy storage resources associated with implementation of the CLCPA. There is little doubt that there will be a major expansion of advanced low and no carbon energy technologies over the coming decades. To the extent that winter fuel and energy security risks tend to be concentrated in downstate load zones, the NYISO may consider evaluating how the interconnection or installation of new renewable and energy storage resources in specific load zones or locations on the bulk power system could provide ancillary winter reliability benefits. For example, an assessment of the magnitude, frequency and duration of potential loss of load events in specific locations/regions, and under plausible system conditions, could identify particular value associated with energy storage resources that meet certain technical specifications (size, discharge rate, and duration) that could mitigate or eliminate identified reliability risks. In a similar vein, to the extent the CLCPA warrants further expansion of transmission system infrastructure, the NYISO could consider how to best plan for and design transmission expansion in a way that mitigates potential fuel security issues.

Ongoing proactive scenario analysis of the potential impacts of the CLCPA. As noted previously, the state of New York is embarking on a period of unprecedented change in many of the critical demand and supply realities in the state; this suggests value in continuing to proactively engage in reliability-focused scenario assessment of New York's ongoing implementation of CLCPA directives, reviewing (a) potential changes in the magnitude and shape of power demand across all seasons under postulated scenarios of electrification of transportation and heating sectors; (b) the likely quantities, technical parameters, and interconnection locations of specific grid-connected and distributed renewable and energy storage resources through 2030; (c) the shape (or hourly generation profile) and effective load carrying capability of grid-connected and distributed solar, onshore wind, offshore wind resources, and energy storage resources; and (d) the impact of changing demand and supply profiles on the resources and operational capabilities needed to maintain power system reliability.

Continuous updating and refinement of fuel and energy security modeling. The results demonstrate that the flexibility afforded by dual fuel capability, particularly downstate, is of critical importance to reliable winter operations throughout the ongoing transformation of the power sector envisioned by the CLCPA. The importance of this capability is expected to persist throughout the ongoing transition of the New York's resource fleet toward a decarbonized grid. The results of the analysis also highlight the potentially significant impacts of timely development of new renewable, energy storage, and other clean energy resources. In light of the ongoing transition of the resource fleet, the NYISO should consider continuing the development, refinement, and application of the fuel and energy security model as a tool for continued assessment of winter operational risks as the system and circumstances change over time. For example, the NYISO should consider periodic refreshing of the analysis herein (or certain key aspects thereof) to account for changes in system conditions over time. The NYISO should also consider using the results of this analysis and the capability provided by the fuel and energy security model to identify certain key metrics that could serve as leading indicators of potential future reliability and/or fuel security concerns (e.g., identifying the magnitude of dual fuel capability that may become unavailable and/or resources such as DEFRs that may be necessary to mitigate adverse impacts to reliable winter operations arise). Such indicators could be used as part of ongoing, proactive monitoring to identify changes in system conditions that would trigger a need for engaging with stakeholders to assess whether further mitigating action is warranted, and, if so, identifying and evaluating potential remedial options.

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PJM, "Winter Storm Elliott Event Analysis and Recommendation Report," July 17, 2023, available at https://www.pjm.com/markets-and-operations/winter-storm-elliott.

PJM, Fuel Security Senior Task Force Summary, FSSTF, December 16, 2019, available at https://www.pjm.com/-/media/committees-groups/task-forces/fsstf/20191216/20191216-item-04-phase-2-summary.ashx.

PJM, Fuel Security Update, Operating Committee, June 10, 2021, available at https://www2.pjm.com/-/media/committees-groups/committees/oc/2021/20210610/20210610-item-13-fuel-security-update-presentation.ashx.

"Retail and Bulk Energy Storage Incentive Programs Reported by NYSERDA," available at https://data.ny.gov/Energy-Environment/Retail-and-Bulk-Energy-Storage-Incentive-Programs-/ugya-enpy.

VIII.Glossary

BA	Balancing authorities
BES	Bulk electric system
BTM	Behind-the-meter
C&I	Commercial and industrial
CLCPA	Climate Leadership and Community Protection Act
CNG	Compressed natural gas
ConEd	Consolidated Edison Company of New York, Inc.
CSC	Cross-Sound Cable
DEFR	Dispatchable emission-free resource
DF	Dual fuel
DMNC	Dependable Maximum Net Capability
EDD	Effective degree day
EDRP	Emergency Demand Response Program
EFORd	Equivalent Forced Outage Rate on Demand
EIA	US Energy Information Administration
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GO	Generator owners
HFS	High fuel storage
HQ	Hydro-Québec
ICAP	Installed capacity
IESO	Independent Electricity System Operation (Ontario)
IM	Import
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
LDC	Local natural gas distribution company
LI	Long Island (load zone K)
LIPA	Long Island Power Authority
LNG	Liquified natural gas
LOL	Loss of load
MMcf	Million cubic feet
MW	Megawatts
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
NYC	New York City (load zone J)
NYCA	New York Control Area
NYDPS	New York State Department of Public Service
NYISO	New York Independent System Operator, Inc.
NYSERDA	New York State Energy Research and Development Authority
PJM	PJM Interconnection, L.L.C.
PD	Physical disruption
PS	Pumped storage
RC	Reliability coordinators
REN	Delayed construction of renewables
RTO	Regional Transmission Organization
SCR	Special Case Resource
SENY	Southeastern New York (load zones G-K)
TOP	Transmission operators
VFT	Linden Variable Frequency Transformer Project

IX. Technical Appendices

A. Cold Weather Study Literature Review

1. Neighboring Region Fuel Security Assessment Status

a) PJM Interconnection

PJM's fuel security initiative is divided into three phases. Phase I was a December 2018 fuel security analysis.[59] The analysis used a full economic dispatch model to analyze 324 cases over a 14-day winter weather event for winter 2023/2024.[60] The results and takeaways of the analysis are summarized as follows: "The PJM system is reliable today and will remain reliable into the future. The analysis results showed some risks and vulnerabilities associated with fuel security. The key variables that have the most impact are: On-site fuel inventory, [o]il deliverability, [a]vailability of non-firm natural gas service, [l]ocation of a pipeline disruption, [and p]ipeline configuration [...]While there is no imminent threat, fuel security is an important component of ensuring reliability and resilience – especially if multiple risks materialize simultaneously. The findings underscore the importance of PJM exploring proactive measures to value fuel security attributes, and PJM believes this is best done through competitive wholesale markets."[61]

Coming out of the Phase I report, PJM pursued Phase II, working with stakeholders to "[...] identify if market, operational or planning changes are needed to address fuel security."[62] In Phase II, the Fuel Security Senior Task Force (FSSTF) worked through an analysis of sensitivities to the Phase I study, an analysis of risk of occurrence of scenarios presenting fuel and energy insecurity, and an analysis of any gaps in incentives and compensation to endure fuel and energy security.[63] This result of Phase II was the sunsetting of the FSSTF in December 2019.[64] The task force voted that there was no immediate threat, to maintain the status quo, and to continue monitoring fuel security, revisiting with stakeholder should risks increase.[65]

Finally, in Phase III, PJM "[w]ork[ed] with federal and state agencies alongside other industry sectors to address any specific security concerns, such as physical and cybersecurity risks."[66] Initial results of Phase III indicated that the impacts of cyber attack scenarios on the bulk energy system "[...] were limited as system conditions [that] never went beyond the implementation of demand response," and that PJM "[w]ill continue to evaluate opportunities for future analysis."[67]

Outside of its formal fuel security evaluation process, another relevant report is PJM's specific event analysis inquiry into Winter Storm Elliott published in July 2023.[68] Winter Storm Elliott occurred from December 23-25,

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[59] PJM Resilience Initiative.

[60] PJM Resilience Initiative, p. 8.

[61] PJM Resilience Initiative, p. 41.

[62] PJM, Fuel Security Update, Operating Committee, June 10, 2021 (hereafter, "PJM June 2021 Fuel Security Update"), p. 5, available at https://www2.pjm.com/-/media/committees-groups/committees/oc/2021/20210610/20210610-item-13-fuel-security-update-presentation.ashx.

[63] PJM, Fuel Security Senior Task Force Summary, FSSTF, December 16, 2019 (hereafter, "PJM December 2019 Fuel Security Senior Task Force Summary"), available at https://www.pjm.com/-/media/committees-groups/task-forces/fsstf/20191216/20191216-item-04-phase-2-summary.ashx.

[64] PJM June 2021 Fuel Security Update, p. 10; PJM December 2019 Fuel Security Senior Task Force Summary, pp. 10-11.

[65] PJM June 2021 Fuel Security Update, p. 10.

[66] PJM June 2021 Fuel Security Update, p. 5.

[67] PJM June 2021 Fuel Security Update, p. 5.

[68] PJM Winter Storm Elliott Report 2023.

2022. During this period, PJM experienced the combination of a holiday weekend, higher than expected peak load, and unanticipated generator outages.[69] The generator forced outages resulted in "substantial Non-Performance Charges,"[70] as part of PJM's capacity performance rules, on the order of $1.8 billion.[71] For part of the period, as much as 25 percent of PJM's total generation fleet experienced forced outages.[72] The 30 recommendations proposed in the report to mitigate negative cold weather impacts on the PJM system in the future fall into five broad categories: (1) enhancing market rules, accreditation, forecasting, and modeling to properly account for winter weather risk, (2) winterizing generators to improve performance, (3) addressing gaps in the coordination and alignment of gas and electric markets, (4) refining and improving "how the Performance Assessment Interval (PAI) system of rewarding or penalizing generator performance is impacted by exports of electricity to other regions," and (5) improving communication regarding emergency procedures between PJM, generation owners, other stakeholders, and states.[73] The report recommendations are currently being addressed through the PJM stakeholder process "including the ongoing Critical Issue Fast Path – Resource Adequacy process that was initiated to produce a set of improvements to PJM capacity market rules by October [2023]."[74]

The Winer Storm Elliot report concludes that "[w]hile PJM and its members were able to maintain reliability during Winter Storm Elliott, the increasing volatility of weather patterns and reliance on gas generation underscore the need to advance the performance of operations, planning and markets for the increasing risk presented by the winter season."[75]

b) ISO-NE

ISO-NE conducted its "Operational Fuel-Security Analysis" study in 2018.[76] The study concluded that "[t]aken together, the study results suggest that New England could be headed for significant levels of emergency actions, particularly during major fuel or resource outages."[77]

Currently, ISO-NE is conducting a new cold weather study in conjunction with Electric Power Research Institute (EPRI) entitled "Operational Impacts of Extreme Weather Events Key Project."[78] The project was initiated in February 2022, with the purpose of conducting "a probabilistic energy-security study for the New England region under extreme weather events and to develop a framework for the ISO to assess operational energy-security risks associated with extreme weather events."[79] The study has three phases: the first is extreme weather modeling performed by EPRI, the second is "risk model development and scenario generation" performed by EPRI, and the

[69] PJM Winter Storm Elliott Report 2023, pp. 1-2.

[70] PJM Winter Storm Elliott Report 2023, p. 2.

[71] PJM Winter Storm Elliott Report 2023, p. 120.

[72] Gas generators accounted for over 70% of the forced outages on December 24th, 2022. See PJM Winter Storm Elliott Report 2023, p. 2.

[73] PJM Winter Storm Elliott Report 2023, pp. 2-3.

[74] PJM Winter Storm Elliott Report 2023, p. 125.

[75] PJM Winter Storm Elliott Report 2023, p. 125.

[76] ISO-NE Operational Fuel-Security Analysis.

[77] ISO-NE Operational Fuel-Security Analysis, p. 9.

[78] ISO-NE, Operational Impacts of Extreme Weather Events Key Project, available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events/.

[79] ISO-NE, Operational Impacts of Extreme Weather Events Key Project, available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events/.

third consists of 21-day energy security assessments performed by ISO-NE.[80] The study models winter and summer events in future years 2027 and 2032,[81] and the latest project status is the release of preliminary results in phase 3 for both winters 2027[82] and 2032.[83]

2. Additional Reports Reviewed

a) NERC and FERC Staff Reports

- *FERC and NERC Staff Report, The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*[84]

This report assesses the conditions leading up to the 2018 Cold Weather Event in the South Central U.S. and provides recommendations for bulk electric systems in order to help prevent similar scenarios. Key recommendations impacting generator cold weather reliability include: the development and enhancement of NERC Reliability Standards (see NERC Project 2019-06 Cold Weather, described below), enhanced outreach to generator owners and operators, and new market rules where appropriate.[85]

- *FERC - NERC Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States*[86] (Winter Storm Uri)

This report describes the conditions of the February 2021 cold weather event (i.e., Winter Storm Uri), its impact on the reliability of the bulk electric system, and recommendations to prevent severe impacts in the future. The report found that 75% of generator outages at issue were caused by either freezing issues, or fuel issues.[87] According to the report, "[t]he simple fact is that the BES cannot operate reliably without adequate generation. When, as during the Event, massive numbers of generating units fail during cold temperatures, eventually grid operators must shed firm customer load to prevent uncontrolled load shedding and cascading outages. These firm load shedding events during cold temperatures are not just another transmission system mitigation technique—they have very real human consequences."[88] Key recommendations to mitigate negative cold weather impacts on the electric grid include proposed modifications to NERC Reliability Standards.[89] The report recommendations specific to NERC Reliability Standards are being addressed by NERC Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination, described below.

- *NERC and FERC, December 2022 Winter Storm Elliott Inquiry into Bulk Power System Operations*[90]

[80] ISO-NE, A08, Operational Impact of Extreme Weather Events, Energy Security Study Performed in Collaboration with EPRI, February 15, 2022, p. 14, available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events/.

[81] ISO-NE, A07, Operational Impact of Extreme Weather Events, Energy Security Study Performed in Collaboration with EPRI, March 15, 2022, available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events/.

[82] ISO-NE, RC A10 Operational Impact of Extreme Weather Events, Preliminary Results of Energy Adequacy Studies for Winter 2027, May 16, 2023, available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events/.

[83] ISO-NE, RC A10(a) Operational Impact of Extreme Weather Events, Preliminary Results of Energy Adequacy Studies for Winter 2032, August 15, 2023, available at https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events/.

[84] FERC NERC January 2018 Cold Weather Report.

[85] FERC NERC January 2018 Cold Weather Report, pp. 86-89.

[86] FERC NERC February 2021 Cold Weather Event Report.

[87] FERC NERC February 2021 Cold Weather Event Report, p. 15.

[88] FERC NERC February 2021 Cold Weather Event Report, p. 189.

[89] FERC NERC February 2021 Cold Weather Event Report, Recommendations 1a to 1j.

[90] NERC/FERC Winter Storm Elliott Inquiry Update.

On December 28, 2022, FERC and NERC opened a "[…] joint inquiry into the operations of the bulk power system during Winter Storm Elliott."[91] As of June 2023, the inquiry remains ongoing. The initial findings are themes consistent with the findings of past FERC and NERC cold weather reports, including emphasizing a "need for generating unit cold weather preparedness," the importance of coordinating, "natural gas [and] electric interdependencies," and a, "need for grid operations preparedness (e.g., load forecasting, grid emergencies)."[92]

b) NERC Projects to Modify and Establish NERC Reliability Standards

- *NERC Project 2019-06 Cold Weather*[93]

The NERC Project 2019-06 was initiated in October 2019 in response to the FERC and NERC staff report, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*. The purpose of the project was to "enhance the reliability of the BES [bulk electric system] during cold weather events by ensuring Generator Owners, Generator Operators, Reliability Coordinators, and Balancing Authorities prepare for extreme cold weather conditions."[94] The project resulted in the adoption of three reliability standards: EOP-011-2, IRO-010-4, and TOP-003-5. EOP-011-2 lays out specific steps and requirements for transmission operators, balancing authorities, reliability coordinators, and generation owners to develop and implement plans to mitigate operating emergencies. IRO-010-4 lays out specific steps and requirements to ensure reliability coordinators have adequate data from all relevant entities in their respective reliability coordinator area to "prevent instability, uncontrolled separation, or [c]ascading outages that adversely impact reliability."[95] Finally, TOP-003-5 lays out the specific steps and requirements to "ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities."[96] These three standards were adopted by the NERC Board on June 11, 2021, and approved by FERC in August 2021. These standards became enforceable on April 1, 2023.

- *NERC Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination*[97]

NERC Project 2021-07 was initiated in November 2021 in response to the recommendations related to NERC Reliability Standards made in the FERC – NERC Regional Entity Staff Report, T*he February 2021 Cold Weather Outages in Texas and the South Central United States*, November, 2021.[98] The purpose of the project "is to develop Reliability Standards to enhance the reliability of the Bulk Electric System (BES) through improved operations, preparedness, and coordination during extreme cold weather […]"[99] The project has two phases. Phase I addresses Reliability Standards EOP-011-3 and EOP-012-1 s. EOP-011-3 is a revised Reliability Standard related to manual and automatic load shed programs.[100] EOP-012-1 is a new extreme cold weather preparedness and

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[91] NERC/FERC Winter Storm Elliott Inquiry Update, p. 2.

[92] NERC/FERC Winter Storm Elliott Inquiry Update, p. 3.

[93] NERC, Project 2019-06 Cold Weather, available at https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx.

[94] NERC, Project 2019-06 Cold Weather, available at https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx.

[95] NERC, Final Draft of IRO-010-4, May 2021, available at https://www.nerc.com/pa/Stand/Project%20201906%20Cold%20Weather%20DL/2019-06_IRO-010-4_Clean_05182021.pdf.

[96] NERC, Final Draft of TOP-003-5, May 2021, available at https://www.nerc.com/pa/Stand/Project%20201906%20Cold%20Weather%20DL/2019-06_TOP-003-4_Clean_05182021.pdf.

[97] NERC, Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination (hereafter, "NERC Project 2021-07 Extreme Cold Weather Grid Operations"), available at https://www.nerc.com/pa/Stand/Pages/Project-2021-07-ExtremeColdWeather.aspx.

[98] NERC Project 2021-07 Extreme Cold Weather Grid Operations.

[99] NERC Project 2021-07, Phase I Implementation Plan, (hereafter, "NERC Project 2021-07, Phase I Implementation Plan"), available at https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07%20Implementation%20Plan_second%20posting_082022.pdf.

[100] NERC Project 2021-07, Phase I Implementation Plan, p. 2.

operations Reliability Standard.[101] Both were approved by the NERC Board in October 2022.[102] Both were also approved by FERC in February 2023, with FERC, requiring some modification to EOP-012-1 to improve and make the new standard more precise.[103]

The project is currently in Phase II. Phase II addresses Reliability Standards EOP-011-4 and TOP-002-5. EOP-011-4 builds upon EOP-011-3 from Phase I.[104] TOP-002-5 "is a revised Reliability Standard that would require the Balancing Authority to specifically address extreme cold weather in its Operating Plans, including developing a methodology to determine the number of resources that can reasonably be expected to be available during extreme cold weather conditions."[105] Both of these standards are currently subject to comment through September 2023.[106]

- *NERC Project 2022-03 Energy Assurance with Energy-Constrained Resources*[107]

Initiated in June 2022, the purpose of NERC Project 2022-03 is to "[…] enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and develop Corrective Action Plan(s) to address identified risks. Energy reliability assessments evaluate energy assurance across the Operations Planning, Near-Term Transmission Planning, and Long-Term Transmission Planning or equivalent time horizons by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period."[108] This project is still in progress. NERC is currently considering stakeholder comments to determine next steps.

c) NERC Alert

- *NERC Level 3 Alert, Essential Actions to Industry*[109]

In May 2023, NERC issued a Level 3 Alert outlining "[…] Essential Actions for Cold Weather Preparations for Extreme Weather Events to increase the Reliability Coordinators' (RC), Balancing Authorities' (BA), Transmission Operators' (TOP), and Generator Owners' (GO) readiness and enhance plans for, and progress toward, mitigating risk for the upcoming winter and beyond."[110] The alert is part of NERC's collective response to the string of recent cold weather events disrupting the electric grid, including the January 2018, February 2021, and December 2022 cold weather events (all discussed above in NERC and FERC Staff Reports).[111]

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[101] NERC Project 2021-07, Phase I Implementation Plan, p. 2.

[102] NERC Project 2021-07 Extreme Cold Weather Grid Operations.

[103] 182 FERC ¶ 61,094, NERC, Docket No. RD23-1-000, Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, pp. 1-6, available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230216-3062&optimized=false.

[104] NERC, Project 2021-07, Phase II Implementation Plan (hereafter, "NERC Project 2021-07, Phase II Implementation Plan"), p. 2, available at https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_AB_Phase%202_Implementation%20Plan_TOP%20and%20EOP-011_clean_August2023.pdf.

[105] NERC Project 2021-07, Phase II Implementation Plan, p. 2.

[106] NERC Project 2021-07 Extreme Cold Weather Grid Operations.

[107] NERC, Project 2022-03 Energy Assurance with Energy-Constrained Resources, available at https://www.nerc.com/pa/Stand/Pages/Project2022-03EnergyAssurancewithEnergy-ConstrainedResources.aspx.

[108] NERC, Project 2022-03 Energy Assurance with Energy-Constrained Resources, available at https://www.nerc.com/pa/Stand/Pages/Project2022-03EnergyAssurancewithEnergy-ConstrainedResources.aspx.

[109] NERC, Essential Actions to Industry, Cold Weather Preparations for Extreme Weather Events III, May 15, 2023 (hereafter, "NERC Level 3 Alert"), available at https://www.nerc.com/news/Pages/NERC-Releases-Essential-Action-Alert-Focused-on-Cold-Weather-Preparations.aspx.

[110] NERC Level 3 Alert, p.1.

[111] NERC Level 3 Alert, p.1.

The Level 3 Alert is not the same as a Reliability Standard, which are subject to penalties under the Federal Power Act for failure to implement.[112] Instead, the Level 3 Alert "[r]equires Registered Entities to acknowledge receipt of these Essential Actions within the NERC Alert System; [r]equires Registered Entities to respond to the questions; and [u]rges Registered Entities to take the Essential Actions[…]"[113] Acknowledgement is required by May 22, 2023, and reporting is required by October 6, 2023, in advance of the upcoming 2023/2024 winter period.[114]

d) NERC Voluntary Reliability Guidelines

- *NERC Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis*[115]

This guideline establishes a "voluntary code of practice […] for consideration by BES [bulk electric system] users, owners, and operators," regarding fuel assurance and grid reliability.[116] Fuel assurance is defined as "[…] proactively taking steps to identify fuel arrangements or other alternatives that would provide confidence such that fuel interruptions are minimized to maintain reliable BPS [bulk power system] performance during both normal operations and credible disruptive events."[117] Under this definition, the guideline outlines considerations and a framework to design fuel assurance reliability assessments. The framework steps largely mirror the assessment described in this report: Step 1: Problem Statement and Study Prerequisites; Step 2: Data Gathering; Step 3: Formulate Study Input Assumptions and Initial System Conditions; Step 4: Contingency Selection; Step 5: Selection of Tool(s) for Analysis; Step 6: Perform Analysis and Assess Results; Step 7: Develop Solution Framework.[118] In the selection of contingencies to study, the guideline recommends examining both high-probability, low-impact contingencies and high-impact, low-probability contingencies such as "[…] severe reduction of non-firm natural gas supply, prolonged pipeline repair, extreme prolonged weather events that affect both supply of and demand for natural gas, or unanticipated low production from variable energy resources (VERs)."[119]

- *NERC Reliability Guideline: Generating Unit Winter Weather Readiness*[120]

This guideline provides a voluntary "[…] framework for developing an effective winter weather readiness program for generating units throughout North America."[121] With its orientation toward generation operators, the guideline provides recommendations for winter readiness in the following categories: safety, management roles and expectations, processes and procedures, evaluation of potential problem areas with critical components, testing, training, and winter event communications.

[112] NERC Level 3 Alert, p. 2.

[113] NERC Level 3 Alert, p. 3.

[114] NERC Level 3 Alert, p. 2.

[115] NERC, Reliability Guideline, Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System, March 2020 (hereafter, "NERC, Reliability Guideline, Fuel Assurance, 2020"), available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf.

[116] NERC, Reliability Guideline, Fuel Assurance, 2020, p. iv.

[117] NERC, Reliability Guideline, Fuel Assurance, 2020, p. 1.

[118] NERC, Reliability Guideline, Fuel Assurance, 2020, pp. 12-22.

[119] NERC, Reliability Guideline, Fuel Assurance, 2020, p. 12.

[120] NERC, Reliability Guide, Generating Unit Winter Weather Readiness – Current Industry Practices – Version 4, June 2023 (hereafter, "NERC, Reliability Guideline, Generating Unit Winter Readiness, 2023"), available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v4.pdf.

[121] NERC, Reliability Guideline, Generating Unit Winter Readiness, 2023, p. v.

- *NERC Reliability Guideline: Gas and Electrical Operational Coordination Considerations*[122]

This voluntary guideline provides information and recommendations to "[…] assist grid operators and owners in the reliable coordination of electric operations with natural gas providers."[123] The guideline is applicable to and should be reviewed by reliability coordinators, balancing authorities, transmission operators, generator owners , and generator operators "[…] in order to ensure reliable coordination with the natural gas industry."[124] The increased penetration of renewable generation, paired with the continued reliance of the grid on natural gas emphasizes the importance of effectively coordinating natural and electric system operations to ensure reliability going forward.[125]

3. Key Themes

Considering the reports and documents highlighted in this section, there is a notable consistency in the cold weather challenges faced by the electric grid across multiple regions, and in the resulting recommendations to mitigate future challenges. Cold weather preparedness is critical to maintain grid reliability in extreme winter conditions. The main themes related to winter reliability and fuel security analysis include:

- It is critical to study winter reliability and generator preparedness.
- NERC reliability standards and alerts emphasize the need for winter preparedness data collection and evaluation.
- An emphasis on the importance of generator access to fuel, and the value of fuel switching capability.
- An emphasis on studying the effect of generator fuel disruption scenarios.
- Considering not only local but regional cold weather impacts on model inputs such as temperature or pipeline gas availability.
- Characterizing and studying both high-probability, low-impact and high-impact, low-probability contingencies.
- An emphasis on the importance of adding transmission to mitigate congestion issues and load loss in extreme weather conditions.
- Specific to Winter Storm Elliott, load losses were largely caused by generation facility equipment failures, gas well freeze-offs, and losses of pipeline compression.

[122] NERC, Reliability Guideline, Natural Gas and Electrical Operational Coordination Considerations, March 2023 (hereafter, "NERC, Reliability Guideline, Natural Gas and Electrical Operational Coordination Considerations, 2023"), available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability%20Guideline%20-%20Gas%20and%20Electric%20Operational%20Coord%20Considerations.pdf.

[123] NERC, Reliability Guideline, Natural Gas and Electrical Operational Coordination Considerations, 2023, p. vi.

[124] NERC, Reliability Guideline, Natural Gas and Electrical Operational Coordination Considerations, 2023, p. v.

[125] NERC, Reliability Guideline, Natural Gas and Electrical Operational Coordination Considerations, 2023, p. 13.

B. Input Data to Natural Gas and Electric System Models

1. 2021-2040 Outlook and 2023 Gold Book Data

The starting point for our electric sector modeling is the 2023 Gold Book and 2021-2040 Outlook. On the supply side, our model begins with units listed as in-service in the 2023 Gold Book and accounts for anticipated resource additions, based on the 2021-2040 Outlook, and deactivations, based on the 2023 Gold Book.

For winter 2023/2024, resource additions are based on the 2021-2040 Outlook "Baseline Case."[126] Winter 2026/2027 resource additions are based on the 2021-2040 Outlook "Contract Case,"[127] with the exception of two offshore wind projects which are assumed to not yet be operational for purposes of this analysis.[128]

The 2021-2040 Outlook "Contract Case" also includes 101 MW of battery storage capacity additions, all of which is associated with a wind or solar project. However, based on currently approved battery storage projects and New York energy storage targets, a total of 899 MW of battery storage is added to the model between winter 2023/2024 and winter 2026/2027 for purposes of this study.[129]

Incremental resource additions between winter 2026/2027 and winter 2030/2031 are based on the 2021-2040 Outlook "Policy Case 1" additions.[130] The two offshore wind projects discussed above that are assumed to first deliver power after winter 2026/2027 are also included in the winter 2030/2031 modeling period. Energy storage resource additions are also added consistent with New York's energy storage targets.

Because the load forecasts used to develop the load shape for the modeling period are not adjusted for behind-the-meter (BTM) solar, we subtract BTM solar from load. The amount of BTM solar included in each future winter is based on the annual projections in Table I-9a of the 2023 Gold Book. The conversion of capacities in Table I-9a from DC to AC assumes 75% efficiency, with a 25% loss.[131]

Table B1 summarizes the incremental resource additions for each winter period based on the methodology described above. In total, the methodology assumes the entry of 20,720 MW of renewable capacity through winter 2030/2031.

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[126] We also include the South Fork offshore wind project as in- service for winter 2023/2024.

[127] 2021-2040 Outlook, Data Documents, "Contract Case Renewable Projects."

[128] These are the 1,230 MW Beacon Wind project, which is expected to first deliver power in the "late 2020s," and the 1,260 MW Empire Wind 2 project, which has an expected delivery date of 2026 in the 2021-2040 Outlook Contract Case and, per its developer, is expected to first deliver power in "the mid-2020s." See Beacon Wind, "Guiding the Future of Energy," available at http://www.beaconwind.com/wp-content/uploads/2022/11/Beacon WindBrochure_r3_WEB.pdf; Empire Wind, "About the Project," available at https://www.empirewind.com/about/project/.

[129] "Retail and Bulk Energy Storage Incentive Programs Reported by NYSERDA," available at https://data.ny.gov/Energy-Environment/Retail-and-Bulk-Energy-Storage-Incentive-Programs-/ugya-enpy.

[130] 2021-2040 Outlook, Data Documents, "Outlook Policy Case Additions."

[131] Based on the maximum conversion efficiency collected from inverter samples across New York during the peak BTM solar generation period in mid to late March and April (77%).

Table B1: New Renewable Entry by Future Winter

Load Zone	Resource	Winter 2023/24 Additions (MW)	Winter 2026/27 Additions (MW)	Winter 2030/31 Additions (MW)	Total Additions (MW)
A	Land Wind	100	340	2,104	2,543
	Offshore Wind	0	0	0	0
	Solar	150	1,352	74	1,576
B	Land Wind	0	147	690	837
	Offshore Wind	0	0	0	0
	Solar	100	661	146	906
C	Land Wind	272	181	1,646	2,099
	Offshore Wind	0	0	0	0
	Solar	217	1,170	215	1,601
D	Land Wind	0	0	199	199
	Offshore Wind	0	0	0	0
	Solar	29	212	17	258
E	Land Wind	106	221	962	1,289
	Offshore Wind	0	0	0	0
	Solar	158	1,014	152	1,324
F	Land Wind	0	0	202	202
	Offshore Wind	0	0	0	0
	Solar	212	978	138	1,328
G	Land Wind	0	0	147	147
	Offshore Wind	0	0	0	0
	Solar	77	336	186	599
H	Land Wind	0	0	0	0
	Offshore Wind	0	0	0	0
	Solar	3	29	23	56
I	Land Wind	0	0	0	0
	Offshore Wind	0	0	0	0
	Solar	4	35	29	68
J	Land Wind	0	0	0	0
	Offshore Wind	0	816	1,230	2,046
	Solar	8	122	120	251
K	Land Wind	0	0	0	0
	Offshore Wind	130	880	1,980	2,990
	Solar	6	195	201	402
NYISO	Land Wind	478	888	5,948	7,315
	Offshore Wind	130	1,696	3,210	5,036
	Solar	964	6,104	1,301	8,369
	Total	**1,572**	**8,688**	**10,460**	**20,720**

Note:
[1] Solar amounts include utility-scale solar and BTM solar.

Generator deactivations are based on the 2023 Gold Book.[132] Units scheduled for deactivation are included in the modeling period for winters prior to their anticipated deactivation. For example, a unit scheduled for deactivation in 2025 would be included in the winter 2023/2024 modeling period and excluded from the winter 2026/2027 and winter 2030/2031 modeling periods.

As discussed in Section III.C.2, the model incorporates wind and solar production profiles directly from the 2021-2040 Outlook. The underlying load shape for the 2021-2040 Outlook is based on the year 2002.[133] As such, the coldest 17-day period in winter 2002 was identified, and the predicted renewable output from the 2021-2040 Outlook during those 17 coldest days was used as the wind and solar output in the model.[134]

The renewable generation output as part of the 2021-2040 Outlook was made available on an hourly basis at the zonal level by renewable type: onshore wind, solar, and offshore wind. The load data from the 2021-2040 Outlook was measured at the hourly level, aggregated by load zone, and included energy efficiency adjustments. For a further discussion of our load modeling see Section III.B.3.

2. Generator Data

In addition to the public data provided in the 2023 Gold Book, the NYISO made additional data available to inform the modeling efforts and help align the modeling effort for this study with historical operating experience. The NYISO provided operational oil storage and replenishment data, and guidance on the operations of nuclear, hydro, pumped storage, battery, and biomass/refuse resources.

Across all resource types, excluding wind and solar, the NYISO provided resource-specific winter Dependable Maximum Net Capability (DMNC) values and resource-specific EFORd derate adjustments. The capacity modeled for all units is the resource-specific DMNC, as adjusted to reflect winter-specific derates. For nuclear facilities, hydro run-of-river facilities, biomass, refuse, the model assumed constant production throughout the 17-day modeling period at winter DMNC values adjusted to reflect winter-specific derates.

Pumped storage, large pondage hydro, and existing batteries are modeled using hourly profiles from the NYISO based on historical and expected operational observations. Specifically, the Niagara facility is assumed by the model to operate for 12 hours at a peak production of 2,200 MW per hour between 9 AM and 9 PM. From 9 PM to 9 AM, the model assumes Niagara operates at 1,000 MW per hour. The model assumes that the four units at the Blenheim-Gilboa pumped storage facility generate approximately 1,165 MW per hour between 3 PM and 9 PM, and then pumps for nine hours between 10 PM and 7 AM.

The model assumes that new battery storage facilities run on a daily charge/discharge cycle where batteries discharge at capacity between 4 PM and 8 PM, and charge during the night between 1 AM and 5 AM, using a round-trip efficiency of 85%. Moreover, to avoid expending fuel oil to charge batteries, the model only charges batteries in a load zone if surplus non-thermal generation is available after meeting load in that load zone.

[132] 2023 Gold Book, Tables IV-4, IV-5, and IV-6.

[133] 2021-2040 Outlook, Appendix C, September 22, 2022, available at https://www.nyiso.com/documents/20142/33395392/2021-2040-Outlook-Appendix-C.pdf/ca02e79f-a0e7-e0d6-cb17-5be775793e77.

[134] The coldest period during the calendar year 2002 was identified using historic weather data from the NYISO. The coldest period was between December 1- 17, 2002, so the model uses predicted wind and solar output from December 1-17 in the 2021-2040 Outlook profiles.

The model also includes load reduction capability made available by SCRs and the EDRP. The model assumes a maximum capability from SCRs/EDRP of 801.5 MW, based on the 2023 Gold Book.[135] The model assumes that SCRs/EDRP can be activated for a maximum of four hours per day, and that over the entire duration of the 17-day modeling period, these resources can only be deployed on five days. The model dispatches SCRs/EDRP zonally only after reducing energy-only exports to ISO-NE.

The oil inventory and replenishment data used in the model was based on fuel survey information reported by generators to the NYISO. Data provided included maximum inventory capacity, replenishment capability, and historical inventory levels for dual fuel and oil only resources. Resource-specific starting inventory levels were determined based on average inventory levels over the last two weeks of November over the past three years, by load zone and by replenishment type (barge or truck). The model assumes that units will refill when their fuel runs down to 50% of the assumed initial inventory. The model assumes the replenishment capability reported by resources in the fuel survey responses submitted to the NYISO to determine both the rate and quantity of inventory replacement available during the 17-day modeling period.

The NYISO also provided unit-specific heat rates based on fuel survey information reported by generators. For units where this information was not available, heat rates were obtained from Hitachi ABB Velocity Suite. The heat rates are used in order to rank the relative efficiency of the fossil plants and determine their order in our stacking analysis

3. LDC Design Day Demand

The LDCs file winter supply information each winter with the New York State Department of Public Service (NY DPS).[136] Table B2 below shows the winter 2022/2023 peak day capability for upstate and downstate LDCs collectively. The "Pipeline + Storage" row reflects the capability used to calibrate the modeled weather conditions and LDC demand relationship for winter 2023/2024. Storage was included in this calibration based on discussions with LDCs, which indicated that storage capacity generally includes firm interstate pipeline transportation.

For winter 2026/2027, the "Pipeline + Storage" capabilities shown in Table B2 were adjusted based on projected LDC peak demand growth, as reported in the LDCs relevant submittals to the NY DPS. Specifically, separately for upstate and downstate, an average growth rate between winter 2022/2023 and winter 2026/2027 was calculated across each LDC, weighted by the winter 2022/2023 "Pipeline + Storage" capability. This yielded a growth rate of 1.07% upstate and 4.45% downstate. Therefore, the values used to calibrate the modeled weather conditions and LDC retail gas demand relationship were 3,104 MMCf/Day upstate and 4,214 MMCf/Day downstate.[137]

For winter 2030/2031, the "Pipeline + Storage" capabilities for LDCs which projected a peak demand day increase between winter 2022/2023 and winter 2026/2027 was assumed to revert to winter 2022/2023 levels. Two LDCs projected a peak demand day decrease between winter 2022/2023 and winter 2026/2027 – NYSEG and Rochester Gas & Electric. For these two LDCs, "Pipeline + Storage" capability was calculated by assuming the implied annual rate of decrease between winter 2022/2023 and winter 2026/2027 would continue between winter 2026/2027

[135] NYISO 2023 Gold Book, p. 67.

[136] See, for example, Consolidated Edison Company, Inc., Case 22-M-0247 – Winter Supply Review Data Request, August 3, 2022, available at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=68031&MNO=22-M-0247.

[137] 3,104 MMCf = 3,071 MMCf * 1.0107, and 4,214 MMCf = 4,035 MMCf * 1.0445.

and winter 2030/2031. In total, "Pipeline + Storage" capability for winter 2030/2031 is estimated at 3,009 MMCf/Day upstate and 4,035 MMCf/Day downstate.

Table B2: Winter 2022-2023 Design Day Capability Summary Table

	NYISO Zone Group Capability		
	Upstate (MMCf)[1]	**Downstate (MMCf)[2]**	**Total Design Day Capability (MMCf)**
Load Zones Covered	A-F	G-K	
Pipeline + Storage[6]	3,071	4,035	7,106
Pipeline[3]	1,895	2,910	4,805
Storage[4]	1,184	1,457	2,642
LNG	0	561	561
Other[5]	22	110	132
Total Design Day Capability (MMCf)	**3,101**	**5,038**	**8,140**

Notes:
[1] Upstate includes Corning Natural Gas Corporation, National Fuel Gas Distribution Corporation, National Grid: Niagara Mohawk, NYSEG, and Rochester Gas & Electric LDCs.
[2] Downstate includes Central Hudson, Consolidated Edison and National Grid: Brooklyn Union and KeySpan LDCs.
[3] Pipeline includes flowing supplies, less NFGSC fuel = National Fuel Gas Supply Co. natural gas pipeline, winter peaking service = "City Gate Delivered by Others and In-Territory Supplies (not LNG or CNG)", total marketer provided supplies, and recallable capacity (AMAs). Assumes all ConEd gas comes from pipeline.
[4] Storage includes storage withdrawals and CNG.
[5] Other includes cogen supplies, local production = "Local Production, landfill gas, renewables, etc. delivered directly into the LDC distribution system", and renewable gas = "Local Production, landfill gas, renewables, etc. delivered directly into the LDC distribution system".
[6] Pipeline + Storage is equal to the sum of pipeline capability and storage capability for all LDCs except Consolidated Edison. For Consolidated Edison, Pipeline + Storage is 1,450 MMCf/day, which reflects the amount of amount of pipeline and storage capacity with firm transportation rights (See Source [H]).

Sources:
[A] Central Hudson Gas & Electric Corporation, Case 21-M-0243 - Winter Supply 2021-22 Forms, July 16, 2021, Table 1.
[B] Consolidated Edison Company, Inc., Case 22-M-0247 - Winter Supply Review Data Request, August 3, 2022, Table 1.
[C] Corning Natural Gas Corporation, Case 22-M-0247 - Winter Supply Review Data Request, July 18, 2022, Table 1.
[D] National Fuel Gas Distribution Corporation, Case 22-M-0247 - Winter Supply Review Data Request, July 15, 2022, Table 1.
[E] Brooklyn Union and KeySpan: National Grid, Case 22-M-0247 - Winter Supply 2022-23 Forms, November 9, 2022, Table 1a.
[F] Niagara Mohawk: National Grid, Case 22-M-0247 - Winter Supply 2022-23 Forms, July 15, 2022, Table 1b.
[G] New York State Electric & Gas and Rochester Gas and Electric, Case 22-M-0247 - 2022-23 Winter Supply Plan September 2022 Update, Table 1.
[H] Consolidated Edison Company, Inc., Gas System Long Term Plan, May 31, 2023, p. 29.

4. S&P Global Market Intelligence Data

S&P Global Market Intelligence data was used in the modeling of New York's natural gas sector. As discussed above, in order to model the relationship between LDC retail gas demand and weather, daily historical data on LDC and end user gas demand from S&P Global Market Intelligence was utilized. This data provides information on the daily historical scheduled capacity at each pipeline point. This analysis used data from pipeline points designated as delivery to LDC or end-user. There are multiple nomination cycles, both day-ahead and intraday, in which LDCs can adjust their scheduled capacity of natural gas for delivery.[138] For the purposes of this analysis, data from the intraday 3 nomination cycle was used because it is the final intraday nomination cycle, and therefore generally represents the most accurate information on the final amount of natural gas delivered at the end of any given day.

5. EIA and S&P Global Market Intelligence Natural Gas Pipeline Data

New York State gas supply was modeled based on data provided by EIA, in its "U.S. State-to-State Capacity" dataset.[139] Assumed gas flows in and out of New York were developed over the following interstate pipelines:

- Algonquin Gas Trans Co
- Central New York Oil and Gas Company
- Columbia Gas Trans Corp
- Dominion Transmission Co.
- Empire Pipeline Inc
- Iroquois Pipeline Co.
- National Fuel Gas Supply Co.
- Norse Pipeline Co.
- North Country P L Co.
- Penn York Energy Corp.
- St Lawrence Gas
- Tennessee Gas Pipeline Co.
- Texas Eastern Trans Corp.
- Transcontinental Gas P L Co.

Across all the pipelines identified above, the total natural gas import capacity into New York State is 14,396 MMcf/d based on EIA data. The total export capacity from New York State to neighboring states and provinces is 7,220 MMcf/d.[140] The pipelines listed above and their associated import and export capacity only represent *interstate* natural gas pipelines. There are additional intra-state pipelines not included in this list, but because this analysis assumes gas is fungible across New York State, subject to certain downstate operational limitations, no assumptions about the capacity of such intrastate pipelines was developed for this study. The study also assumes that no new import or export pipeline capacity is added to New York State over the winter periods analyzed.

The study assumes that all interstate pipelines connecting New York to the PJM region are fully committed for import into New York. Under this assumption, gas flows into New York from the PJM region are 10,186 MMCf/d, corresponding to the EIA reported import capacity across all pipelines from New Jersey and Pennsylvania into New York. Assumed gas flows into New York from Ontario are 945 MMCf/d, based on average daily flows in winter 2021/2022 from Ontario into New York across the Iroquois, Empire, and Tennessee Gas Pipelines, as compiled by

[138] FERC, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, Order No. 809, 151 FERC ¶ 61,049 (April 16, 2015), available at https://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf.

[139] EIA, Natural Gas Pipeline Data, "U.S. State-to-State Capacity," available at https://www.eia.gov/naturalgas/data.php.

[140] Some of these import/export capacity values are on bidirectional pipelines.

S&P Global Market Intelligence. Assumed gas flows from New York to New England are 3,550 MMCf/d, also based on S&P Global Market Intelligence data.[141]

6. Maximum Natural Gas Supply for Generation

The natural gas system supply capability developed for this study is based on pipeline capacity and interstate gas flow data, as detailed above. These import and export capacities in conjunction with a review of LDC commitments are used to determine the total amount of gas available to New York State for all purposes (heating, industrial, electric power generation, etc.). As discussed in Appendix B.5, this analysis assumes that in each winter period studied, the net gas imports from PJM and Ontario total approximately 11,131 MMCf/d, and that net gas exports to New England total 3,550 MMCf/d.

As discussed in Appendix B.3, estimated design day LDC retail gas demand is 7,106 MMCf/d for winter 2023/2024, 7,318 MMCf/d for winter 2026/2027, and 7,044 MMCf/d for winter 2030/2031. Table B3, Table B4, and Table B5 present the determination of gas available for electric generation under design day conditions for winter 2023/2024, winter 2026/2027, and winter 2030/2031, respectively. For each winter period studied, design day gas available for electric generation is calculated based on net gas imports into New York from the PJM region and Ontario, net of exports to New England and design day LDC retail gas demand.

Table B3: New York State Modeling Period Gas Supply and Demand (MMcf/d)

Winter 2023/2024

Gas Supply/Demand	MMCF/d	Calculation	Source
Modeling Period Supply			
Max New York State Imports from PJM	10,186	[A]	EIA
Expected New York State Imports from Ontario	945	[B]	S&P Global
Gas Available within New York	***11,131***	***[C] = [A] + [B]***	
Modeling Period Demand			
Expected Exports to New England	(3,550)	[D]	S&P Global
New York Design Day LDC Demand	(7,106)	[E]	NYDPS
Total Outflows/LDC Demand	***(10,656)***	***[F] = [D]+[E]***	
Max Gas Available for Electric Generation in New York	**475**	**[G] = [C] + [F]**	
Equivalent MW of Gas Generation Capacity each Hour at 9 MMBtu/MWh Heat Rate	**2,281**	**[H] = [G] * 4.8**	

[141] LeeVanShcaick, P. and Coscia, J., Potomac Economics, MMU Analysis of Gas Availability in Eastern New York, October 20, 2022, p. 17.

Table B4: New York State Modeling Period Gas Supply and Demand (MMcf/d)

Winter 2026/2027

Gas Supply/Demand	MMCF/d	Calculation	Source
Modeling Period Supply			
Max New York State Imports from PJM	10,186	[A]	EIA
Expected New York State Imports from Ontario	945	[B]	S&P Global
Gas Available within New York	***11,131***	***[C] = [A] + [B]***	
Modeling Period Demand			
Expected Exports to New England	(3,550)	[D]	S&P Global
New York Design Day LDC Demand	(7,318)	[E]	NYDPS
Total Outflows/LDC Demand	***(10,868)***	***[F] = [D]+[E]***	
Max Gas Available for Electric Generation in New York	**263**	**[G] = [C] + [F]**	
Equivalent MW of Gas Generation Capacity each Hour at 9 MMBtu/MWh Heat Rate	**1,261**	**[H] = [G] * 4.8**	

Table B5: New York State Modeling Period Gas Supply and Demand (MMcf/d)

Winter 2030/2031

Gas Supply/Demand	MMCF/d	Calculation	Source
Modeling Period Supply			
Max New York State Imports from PJM	10,186	[A]	EIA
Expected New York State Imports from Ontario	945	[B]	S&P Global
Gas Available within New York	***11,131***	***[C] = [A] + [B]***	
Modeling Period Demand			
Expected Exports to New England	(3,550)	[D]	S&P Global
New York Design Day LDC Demand	(7,044)	[E]	NYDPS
Total Outflows/LDC Demand	***(10,594)***	***[F] = [D]+[E]***	
Max Gas Available for Electric Generation in New York	**537**	**[G] = [C] + [F]**	
Equivalent MW of Gas Generation Capacity each Hour at 9 MMBtu/MWh Heat Rate	**2,578**	**[H] = [G] * 4.8**	

C. Evaluation Process for Developing Cases of Interest

1. Step One: Determine Probability of Occurrence

	Winter 2023/2024 Scenarios			
Disruptions	**Scenario 1:** Initial Conditions + IM All	**Scenario 2:** Initial Conditions + IM Net0	**Scenario 3:** Initial Conditions + IM All + HFS	**Scenario 4:** Initial Conditions + IM Net 0 + HFS
1. No Disruptions (Starting Conditions)				
2. High Outage				
3. SENY Deactivation				
4. Nuclear Station Outage				
5. No Truck Refill				
6. No Barge Refill				
7. No Refill				
8. Non-Firm Gas Unavailable (F-K)				
9. Non-Firm Gas Unavailable (NYCA)				
10. Non-Firm Gas Unavailable (4 days)				
11. Combination Disruption				

<u>Consequence: Assessed based on magnitude, duration, and frequency of loss of load, grouped as follows:</u>

Highly unlikely to occur - probability far outside typical conditions used in system operational assessments

Probability *meaningfully less likely than* tpyical conditions used in system operational assessments

Probability on the order of typical conditions used in system operation assesments

<u>Scenario Key</u>

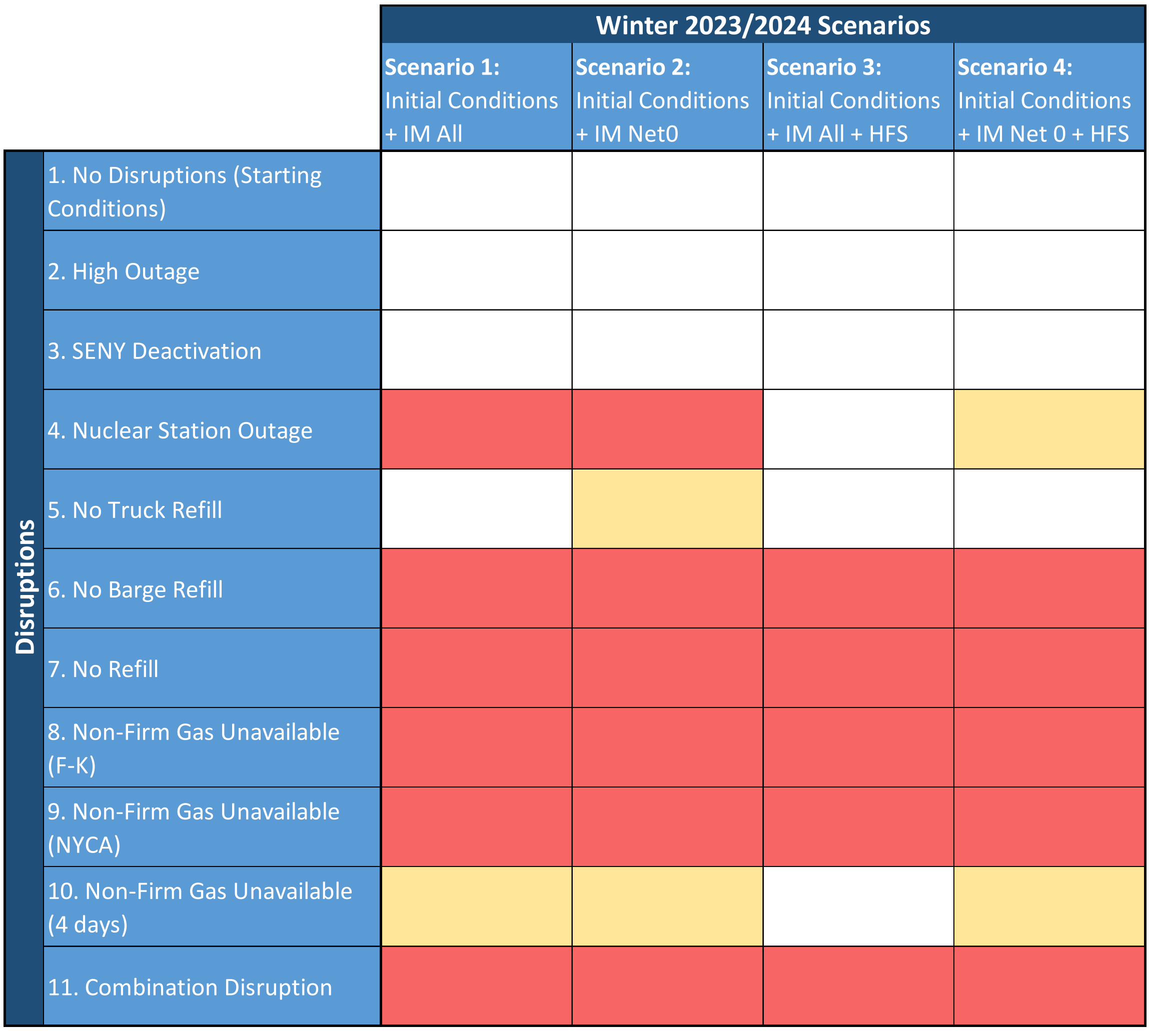
IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.

IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.

HFS = Higher starting oil tank levels, 50% increase in starting storage levels.

Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

2. Step Two: Determine Consequence and Ease of Mitigation



Consequence: Assessed based on magnitude, duration, and frequency of loss of load, grouped as follows:

- (White) Loss of load zero or less than 100 MW, with short duration (less than 4 hours), that is infrequent (not more than two events over cold snap)
- (Yellow) Loss of load between 100 and 1,500 MW, with moderate duration (up to 12 hours), that is not infrequent (two or three events over cold snap)
- (Red) Loss of load greater than 1,500 MW OR between 100 and 1,500 MW with longer duration (more than 12 hours) OR between 100 and 1,500 MW that is frequent (more than three events over cold snap)

Scenario Key

IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

3. Step Three: Combined Assessment to Develop Cases of Interest

		Winter 2023/2024 Scenarios			
		Scenario 1: Initial Conditions + IM All	Scenario 2: Initial Conditions + IM Net0	Scenario 3: Initial Conditions + IM All + HFS	Scenario 4: Initial Conditions + IM Net 0 + HFS
Disruptions	1. No Disruptions (Starting Conditions)				
	2. High Outage				
	3. SENY Deactivation				
	4. Nuclear Station Outage				
	5. No Truck Refill				
	6. No Barge Refill				
	7. No Refill				
	8. Non-Firm Gas Unavailable (F-K)				
	9. Non-Firm Gas Unavailable (NYCA)				
	10. Non-Firm Gas Unavailable (4 days)				
	11. Combination Disruption				

Note: The scale of the axes are equal in all cells. The y-axis is set to have a maximum of 10,000 MW.

Consequence 0-100 MW or probability extremely low (far outside normal operational assessments)
Consequence 100 - 1,500 MW, of moderate duration/frequency, and probability low or on the order of normal operational assessments
Consequence greater than 1,500 MW, and probability low (meaningfully less likely than normal operational assessments)
Consequence greater than 1,500 MW, and probability on the order of normal operational assessments

<u>**Scenario Key**</u>
IM All = 1,200 MW capacity imports / minimum 300 MW capacity exports.
IM Net0 = 300 MW capacity imports / minimum 300 MW capacity exports.
HFS = Higher starting oil tank levels, 50% increase in starting storage levels.
Combination Disruption = 50% gas available NYCA-wide + 50% increased lead time for oil refill + High Outage Disruption 2.

D. Loss of Load Duration Curves for all Scenarios and Disruptions

E. Diagnostic Charts for All Cases