Memorandum

TO: Richard J. Dewey

FROM: David Patton, Pallas LeeVanSchaick, and Joseph Coscia

DATE: October 17, 2022

RE: MMU Comments on 2022 Reliability Needs Assessment

The Reliability Needs Assessment ("RNA") is the first step in the NYISO's Comprehensive System Planning Process ("CSPP"). The RNA identifies the reliability needs for the Bulk Power Transmission Facilities ("BPTF") over a 10-year study period based on a set of assumed (i.e., Base Case) conditions. After the RNA identifies reliability needs and solicits proposals for market-based and regulated solutions, the Comprehensive Reliability Plan ("CRP") identifies the set of solutions that could be used to satisfy the reliability needs over the study period. The CRP also indicates whether any regulated solution must move forward to satisfy the system's reliability needs in any year during the study period.

As the Market Monitoring Unit for the NYISO, we are required to provide comments on the RNA regarding whether market design changes are needed to provide better incentives for the markets to help satisfy the reliability needs of the system.[1] This memo provides our comments on the 2022 RNA and highlights areas of the NYISO's market design that fail to provide appropriate incentives.

A. Executive Summary

The 2022 RNA finds that New York's bulk transmission system as planned satisfies all applicable reliability criteria through 2032 under base case conditions. However, reliability margins are expected to be tight or negative in the event of extreme weather, especially in New York City. In this memo we discuss market design enhancements that are needed: (1) to reflect fuel supply limitations for gas-dependent generation during peak winter conditions and provide appropriate incentives for investment in fuel secure resources, and (2) to ensure that transmission security planning criteria are reflected appropriately in the accreditation of resources that sell capacity.

1 See NYISO MST Section 30.4.6.8.2. "Following the Management Committee vote," the MMU evaluates "whether market rules changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets."

Winter Fuel Supply Limitations

Winter reliability risks are growing in New York and New England. While peak demand is higher in the summer than in the winter, a large amount of capacity becomes unavailable in winter, which could lead to tighter resource margins in the winter. However, NYISO's planning studies and markets are currently designed primarily to consider summer reliability needs. Hence, they may not adequately detect winter reliability issues or motivate market participants to take action to address them.

Existing gas pipeline infrastructure cannot reliably provide fuel to generators in eastern New York in very cold conditions. The combined region of eastern New York and New England can import approximately 8.3 million Dth/day of natural gas via interstate pipelines, but firm heating demand from gas utilities (before considering demand from power generators) can exceed 10 million Dth/day in the coldest conditions. When pipelines are fully utilized, additional gas comes from LNG that is stored in utilities' limited on-system tanks or imported via LNG terminals in New England. Generators typically lack firm contracts for pipeline transportation or LNG imports.

Figure 1 below shows average output by gas-fired generators in eastern New York and New England on the highest-load days of the past five winters, excluding generation that was made possible by LNG imports. As winter peak load increases towards NYISO's 90th percentile forecast, pipeline gas generation becomes minimal as all pipeline gas is consumed by utilities.

Figure 1: Winter Peak Pipeline Gas Generation in Eastern NY and New England

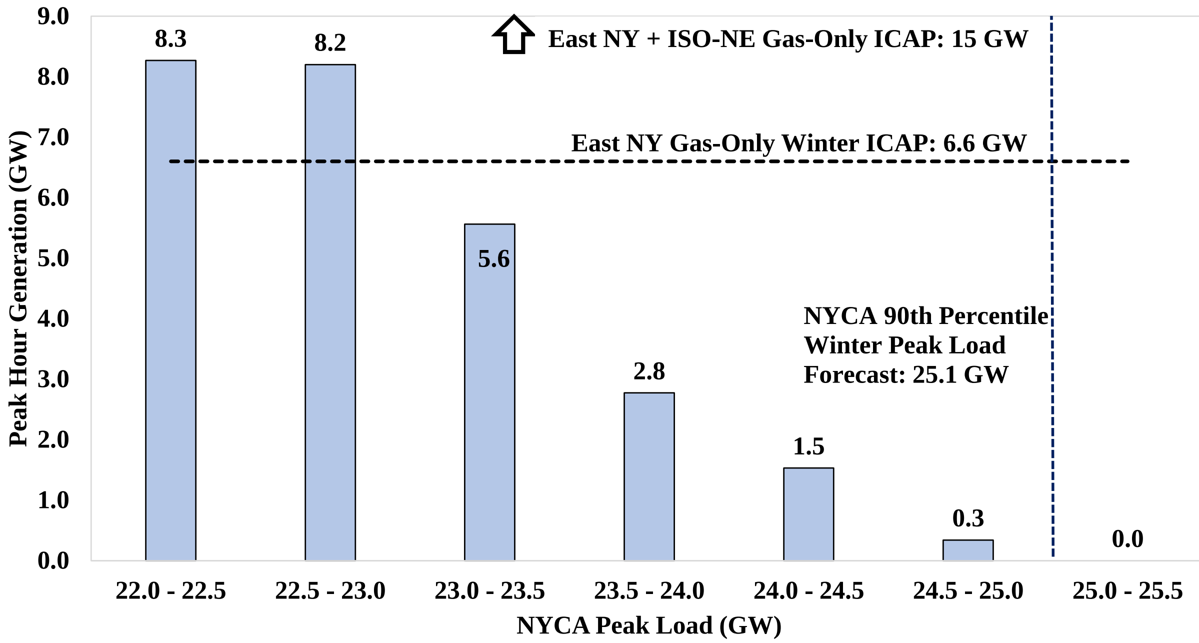
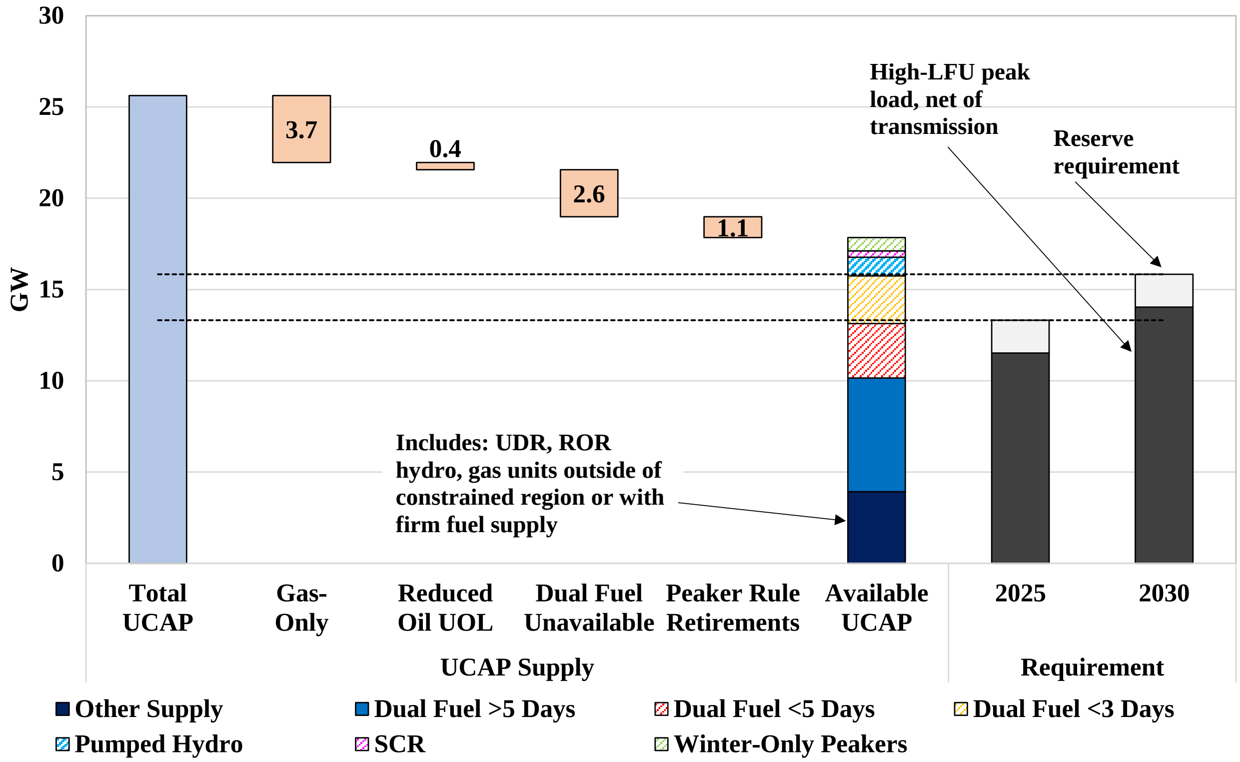


Figure 2 demonstrates that winter resource margins are significantly smaller when unavailability of certain resources is considered. Over 6 GW of UCAP in eastern New York is currently assumed to be available in the capacity market but is likely to be unavailable because of gas limitations. An additional 1.1 GW of dual fuel peakers plan to retire by 2025. Moreover, winter peak demand is forecasted to grow over the coming decade. As a result, winter reliability will depend on the ability of dual fuel units with limited oil inventories to sustain operation during extended high-load winter events.

Figure 2: Eastern New York Winter Supply-Demand Balance



NYISO's markets are not designed to signal when winter supply margins are tight because of limitations on the availability of generation or to incentivize resource owners to improve it. In particular, we highlight the following market design deficiencies:

- **Resources without firm fuel are over-accredited in the capacity market in the winter.** To address this concern, we recommend modifying MARS to consider the availability of each resource type in NYISO as well as resources in neighboring systems during winter peak load conditions. This would also allow the NYISO to develop appropriate Capacity Accreditation Factors for affected resources.
- **Seasonal capacity prices don't reflect seasonal reliability needs.** To address this, we recommend modifying the translation of the annual revenue requirement for the demand curve unit into monthly or seasonal demand curves that consider reliability value.
- **Existing capacity zone configuration does not reflect locational reliability needs in the winter**. To address this concern, we recommend reflecting specific capacity needs for the area east of the Central-East interface by creating an F-K Locality in the capacity market or by implementing locational marginal pricing of capacity ("C-LMP").

Transmission Security Criteria

NYISO models certain resource types more conservatively in transmission security analysis than resource adequacy analysis. These include emergency demand response providers known as Special Case Resources (SCRs), emergency assistance from external areas, and large-contingency resources. This is likely to cause Locational Capacity Requirements (LCRs) to increasingly be set based on Transmission Security Limits, which will lead consumer costs to increase because the capacity market will compensate suppliers that provide little or no benefit towards satisfying the transmission security planning criteria.

To address these issues, we recommend (a) considering modifications to the transmission security and resource adequacy analyses to ensure resources are modeled using reasonable assumptions, and (b) compensating resources based on their contribution to transmission security if transmission security needs are used to determine capacity requirements (i.e., if LCRs are set by the TSL methodology).

B. Summary of 2022 RNA Findings

The 2022 RNA finds that New York's bulk transmission system as planned satisfies all applicable reliability criteria through 2032 under base case conditions:

- The RNA's base case resource adequacy analysis finds that loss of load expectation (LOLE) remains well below the reliability criterion of 0.1 days per year, with a maximum value of 0.025 days/year in 2023.
- The base case transmission security analysis finds that reliability is preserved statewide and in each locality through 2032. However, the transmission security analysis finds a much smaller capacity margin than the resource adequacy analysis. The transmission security analysis finds a margin of just 50 MW in New York City in 2025, while the resource adequacy analysis finds a margin of nearly 900 MW for the same area in the same year. Transmission security analysis uses more conservative assumptions than resource adequacy analysis.

Sensitivity analyses suggest that reliability issues could emerge if conditions differ from those studied in the base case. Transmission security margins in New York City are expected to be very tight by 2025 and could become negative in the event of slightly higher load, additional resource retirements or delay of the planned CHPE HVDC project. The statewide margin is expected to become negative during the study period during extreme (hot or cold) weather conditions.

The RNA also includes sensitivities that evaluate reliability during winter gas shortage conditions. It evaluates winter reliability assuming that 6.3 GW of generation lacks dual fuel capability or firm fuel supply. This analysis finds that statewide margins could be violated by the early 2030s and earlier under extreme cold weather conditions. Resource adequacy analysis finds that LOLE rises in a gas shortage scenario but does not exceed the 0.1 days/year criterion. However, this analysis may understate reliability risk in winter because it does not consider (1) that New York likely cannot draw on assistance from ISO-NE during cold conditions because

New England generators are affected by the same fuel supply restrictions, (2) whether dual fuel units have sufficient oil inventories to run continuously in extended cold conditions when gas in unavailable regionally, and (3) the balance of supply and demand for the area east of the Central-East Interface (i.e., Zones F-K), which is import constrained during winter conditions. In the following section, we analyze the availability of generation resources in winter and discuss implications for NYISO's reliability and markets.

C. Comments on NYISO Winter Reliability

Reliability risks are growing in winter months in New York and New England because of limitations on the availability of natural gas. However, NYISO's planning studies and capacity market are currently designed primarily to evaluate reliability needs during the summer when demand is highest. Hence, the planning studies and capacity market may not adequately detect winter reliability issues or motivate market participants to take action to address them.

This section discusses: (1) evidence that generators that depend on pipeline gas are likely to be unavailable in very cold winter weather, (2) the implications for NYISO's winter reserve margins, and (3) changes to NYISO's markets that are needed to address winter reliability needs.

1. Most generators in eastern New York cannot obtain gas in peak winter conditions

Pipeline bottlenecks limit the total supply of natural gas that can be imported to eastern New York and New England during periods of high winter demand. This region has no natural gas production and no large underground gas storage facilities. Hence, all gas for heating and electric demand is imported via interstate pipelines or LNG terminals. Firm transportation on pipelines is mainly held by gas utilities (LDCs), and winter heating demand is prioritized above power generation. This implies that gas available for power generators in eastern New York is limited by (1) maximum pipeline flows into the region and (2) gas consumed by LDCs, including LDCs located downstream in New England.

Figure 3 shows a map of natural gas pipelines serving eastern New York and New England, as well as major LDC territories in eastern New York. Gas pipeline bottlenecks limit total deliveries into New York City and Long Island and to areas east of Station 245 on the Tennessee pipeline and Stony Point on the Algonquin pipeline. This region roughly corresponds to NYISO zones F through K (excluding Rockland County in zone G) and all of New England.

Interstate pipelines do not have enough capacity to satisfy regional gas demand. Figure 4 compares the combined capacity of pipelines serving eastern New York and New England to the peak winter demand of LDCs. The LDCs' Design Day demand (i.e., demand of firm gas customers under extreme cold conditions for which LDCs plan their systems) exceeds 10 million Dth/day, while interstate pipelines are capable of providing approximately 8.3 million Dth/day. Design Day demand reflects conditions much colder than those typically experienced. The figure shows that estimated peak demand of LDCs under weather conditions similar to late 2017/early 2018 cold snap would be approximately 8.8 million Dth/day, which still exceeds the capability of interstate pipelines. Since pipeline gas is insufficient, LDCs also rely on gas that is stored in on-system LNG tanks before each winter and imports of LNG by ship.

Figure 3: Gas Pipeline and LNG Terminal Map

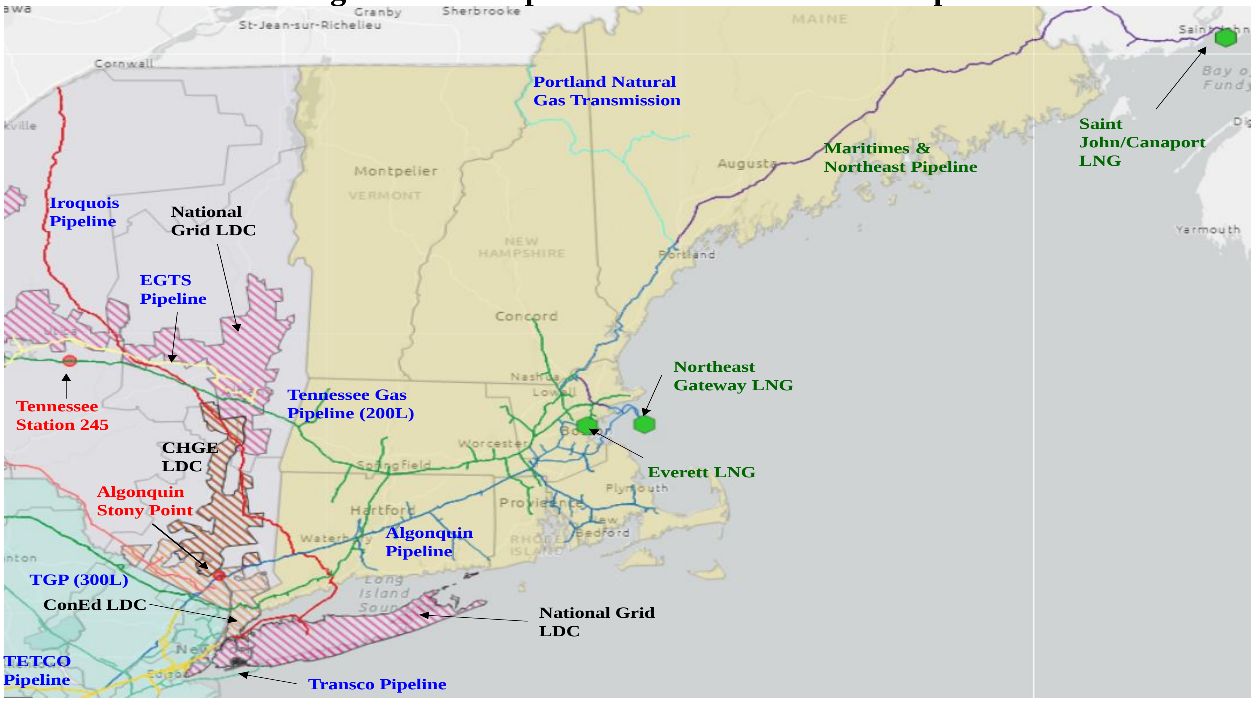


Figure 4: Summary of LDC's Gas Supply and Demand

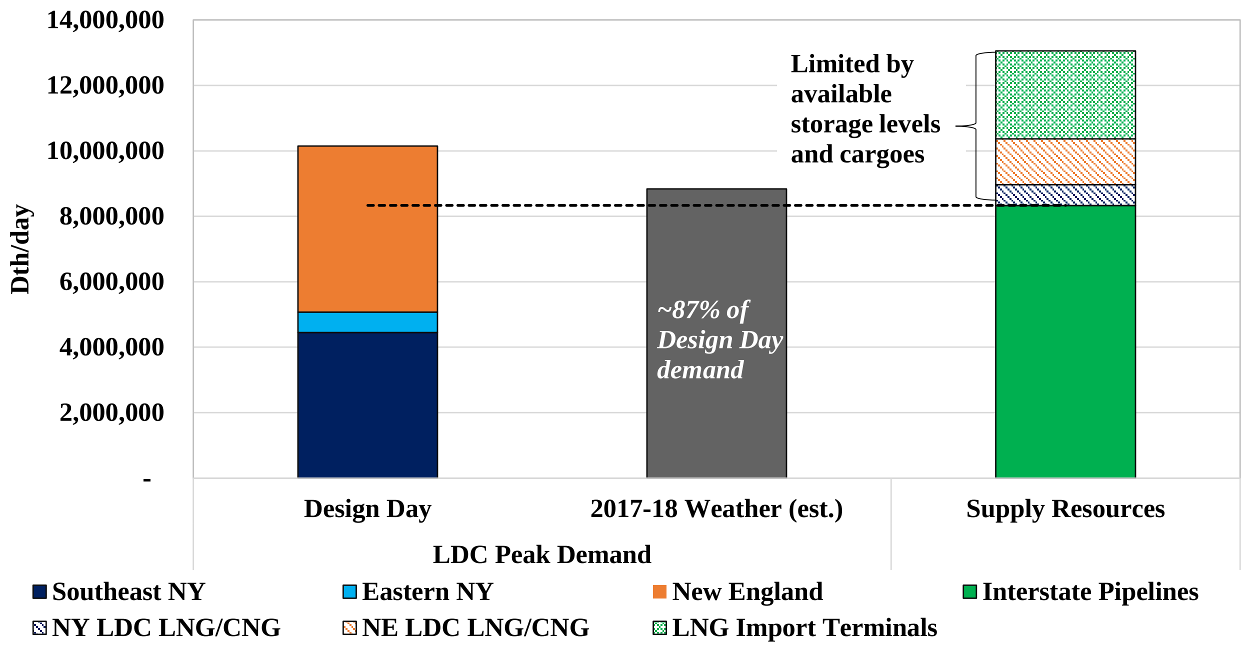
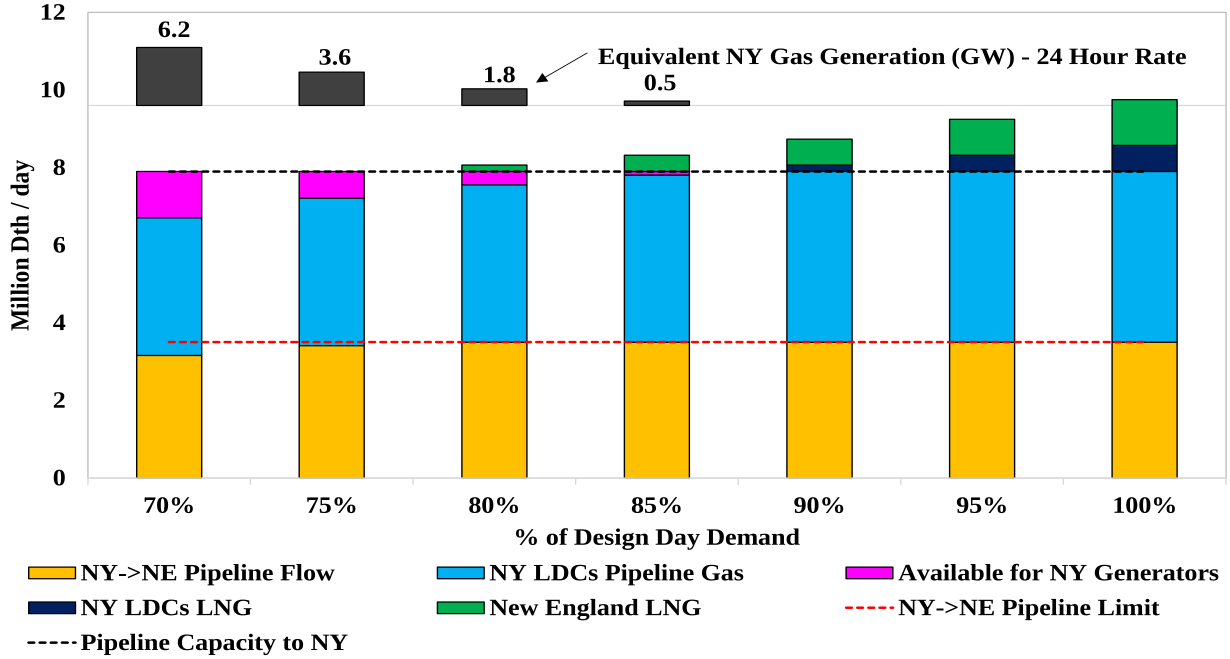


Figure 5 illustrates how external and internal pipeline constraints affect the availability of gas to power generators in eastern New York. When the demand of LDCs is low compared to Design Day levels (as shown on the left side of the figure), there is gas available for generators after LDCs' demand is satisfied.

Figure 5: Illustration of Gas Available for Generators



As LDC demand rises, small amounts of gas may remain available to generators in eastern New York. However, at high levels of LDC demand, all available pipeline gas is consumed by firm customers and any additional demand – whether from LDCs or generators – must be satisfied by stored or imported LNG. The dark bars at the top of the graph show the amount of eastern New York generation that could be supplied without importing LNG, assuming an 8 Dth/MWh heat rate and a 24-hour "operational flow order" commonly issued by pipelines and LDCs during cold conditions.

Data from recent cold winters demonstrates that the availability of gas to generators generally depends on imported and/or stored LNG under peak conditions. Figure 6 compares pipeline gas and LNG imports to on-peak power generation in eastern New York and New England during the 2017-2018 winter. During the cold snap of late December and early January, pipeline gas imports reached their limits and LNG imports to the region increased. The relatively small amount of gas-fired power generation that continued to run during this period likely would not have been possible without LNG imports adding to the regional gas supply. Generators in New York and New England lack strong incentives to contract with LNG shippers and generally do not do so. While imports in recent winters have resulted in gas being available for generators, it is dangerous to assume this will occur if demand is very high and firm customers make full use of their contracted supplies.

Figure 6: Pipeline Gas, LNG, and Generation in Winter 2017/18

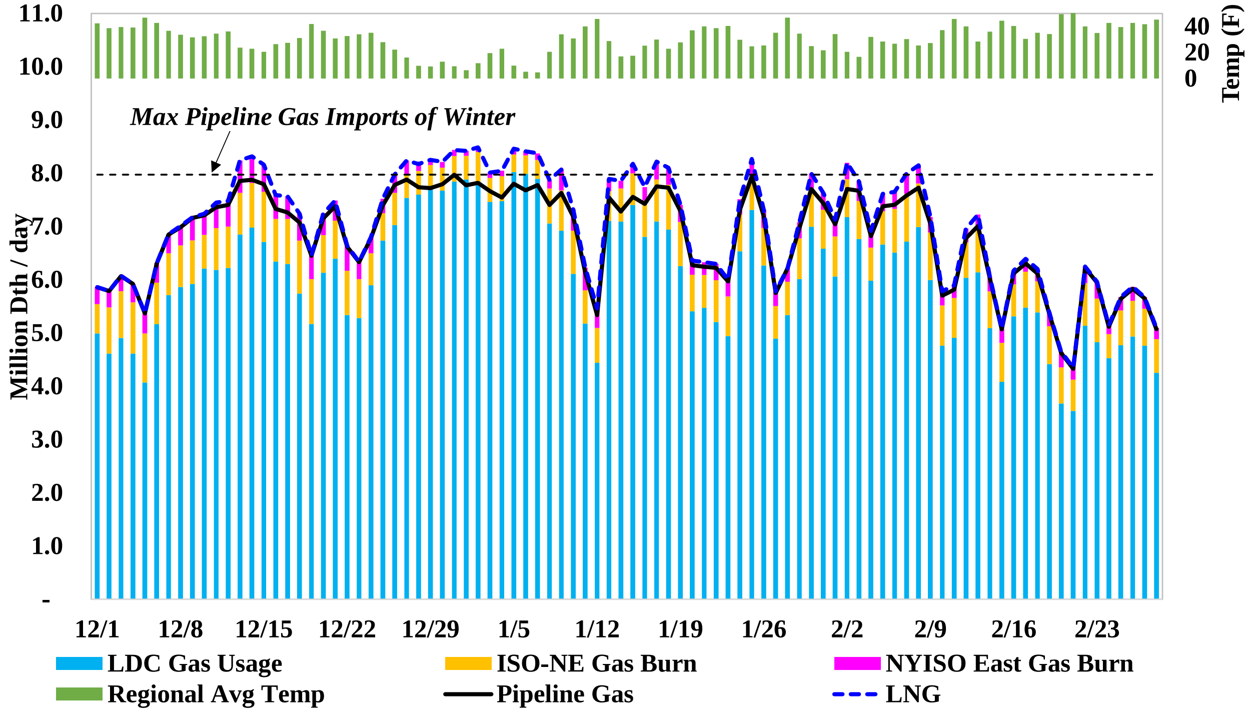
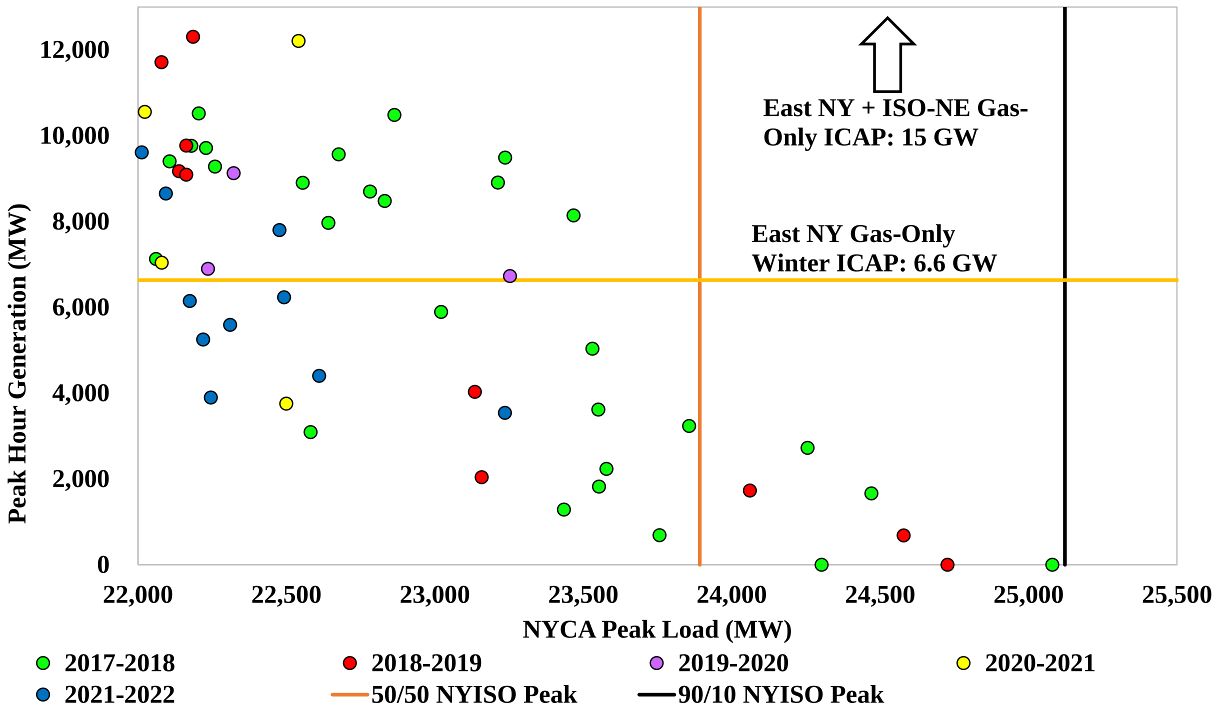


Figure 7 shows MW of historical on-peak pipeline gas-fueled generation on the Y-axis and daily peak load on the X-axis. Each data point is colored according to the winter when it took place. For each region, the baseline (50/50) winter peak forecast and 90/10 winter peak forecast from the 2022 Gold Book are shown for reference as vertical orange and black lines, respectively. The total winter ICAP of gas-only generators is shown as a gold horizontal line. We calculate pipeline gas-fired generation by subtracting regional LNG imports from the total gas burn of power generators if interstate pipeline flows are at their limits. The purpose of this approach is to exclude generation that was made possible only because of LNG imports for which generators typically do not have contracts.

Figure 7 shows that as winter load increases, pipeline gas-fueled generation tends to decrease. The coldest winter days of the past five years have seen minimal pipeline gas generation across the entire region. An analysis of resources available to perform during winter peak conditions should significantly discount these generators unless they are known to have firm fuel supply that will not be curtailed as demand from LDCs rises on cold days.

Figure 7: Winter Peak Pipeline Gas Generation in Eastern NY and New England



2. *NYISO's Winter Capacity Margins are Overstated and Declining*

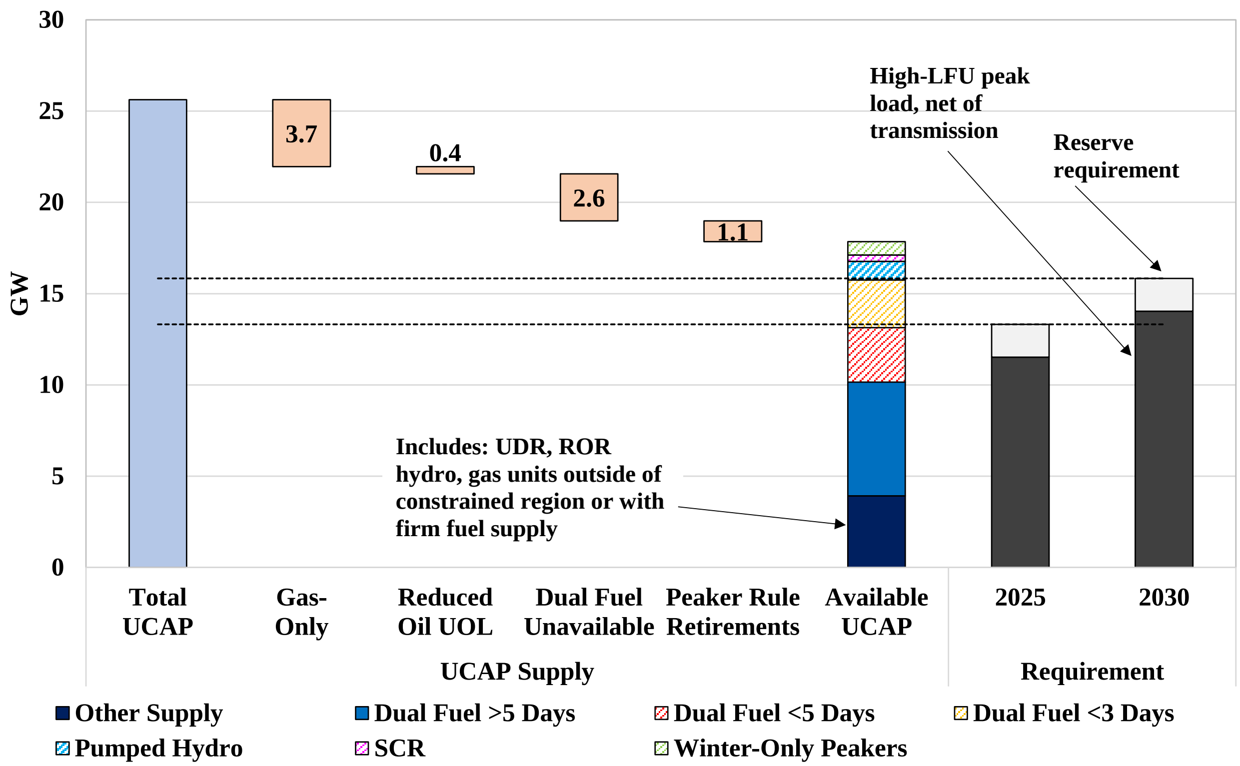
Reliability is generally determined by (1) the level of demand and (2) the resources available to satisfy that demand. NYISO's reliability planning has historically concentrated on summer because peak load is much higher in summer than winter. However, as the previous section demonstrates, large amounts of capacity that are available in summer may be unavailable in winter. Winter reliability may therefore be tighter than has previously been assumed in planning studies. Over the next decade, winter reliability risk is likely to increase relative to summer because peak winter demand is expected to grow at a much faster rate and because some winter-capable capacity is planned to retire.

Figure 8 examines the impact of resources with limited winter capability on winter reliability margins, particularly the following groups:

- Gas-Only: gas-fired resources that lack dual fuel capability in areas of eastern New York where gas is unlikely to be available under extreme peak winter conditions;
- Reduced Oil UOL: dual fuel resources whose upper operating limits are reduced when switching to oil;
- Dual Fuel Unavailable: dual fuel resources that cannot run on oil in practice because oil-firing capabilities and/or permitting requirements have not been maintained in areas of eastern New York where gas is unlikely to be available in high peak winter conditions;
- Peaker Rule Retirements: gas turbines with dual fuel capability that have indicated they plan to retire by 2025 to comply with the NYSDEC "Peaker Rule" regulations.

After removing these resources, 18.4 GW of winter UCAP remains available, compared to a projected requirement (including reserve needs) of 13.3 GW in 2025. However, 7.4 GW of this supply is from resources that might not be available for the duration of a prolonged cold snap. These include dual fuel units with small oil inventories, SCRs, pumped storage hydro, and gas turbines in New York City that have not announced they will retire but will not be permitted to operate during the 5-month ozone season to comply with the DEC Peaker Rule (and will therefore receive heavily-reduced capacity revenues). In addition, winter peak load growth of 2.3 GW is expected between 2025 and 2030, which will further reduce winter margins.[2] Hence, detailed probabilistic modeling of winter conditions (including consideration of dual fuel resources' ability to run during an extended cold snap) could reveal that winter reliability is less secure than is currently assumed.

Figure 8: Eastern New York Winter Supply Balance



There are additional factors that could lead the capacity margin to be significantly tighter than shown above. First, dual fuel units are not required to maintain this capability or fill their oil tanks in order to satisfy their capacity obligations in the winter under the current market rules. So, some units may opt not to be available on oil if it is unlikely to be profitable in a particular winter. Second, the available capacity could fall further if dual-fuel generators retire, experience a catastrophic forced outage, or export capacity to a neighboring area such as New England.

2 The rapid increase in forecasted winter demand is driven primarily by the projected conversion of gas heat to electric heat. While this will reduce the peak demand of LDCs, it will likely reduce LNG imports. Consequently, it is unlikely to make additional gas available to electric generators during peak conditions.

3. Market Design Improvements are Needed to Address Winter Reliability

There are multiple actions that resource owners could take to improve NYISO's winter reliability. These include: (a) maintaining dual fuel capability (or making investments to restore it), (b) maintaining ample oil inventories on dual fuel units, (c) procuring firm gas supplies to the extent that they are available (including contracting for LNG imports), (d) maintaining resources that operate only outside of the summer ozone season to comply with NYSDEC regulations in service, and (e) investing in new resources that are available in winter and comply with environmental laws. Some of these actions may improve reliability at low cost, while others may require large investments. However, resource owners cannot be expected to take any these actions unless market signals reward them for doing so.

NYISO's markets are not designed to signal when the value of winter reliability is high or reward resources based on their ability to improve it. In particular, we highlight the following market design deficiencies:

Resources without firm fuel are over-accredited in the capacity market. Gas-fired generators that lack dual fuel capability or firm fuel supply arrangements are assumed to be available in GE-MARS if not experiencing a forced outage. But as we have seen, most of these units are likely to be unavailable in severe winter conditions. Generators in New England are also assumed to be available to provide emergency support to NYISO, without consideration for their fuel constraints. This creates two problems. First, MARS will not accurately assess the degree of reliability risk NYISO faces in winter. Second, the marginal capacity value of resources that depend on pipeline gas will appear to be high in winter even if they would in practice be unavailable during peak winter conditions. As a result, resource owners lack incentives to firm up their fuel supplies or invest in winter-capable resources.

To address this concern, we recommend modifying MARS to consider the availability of each resource type in NYISO as well as resources in neighboring systems during winter peak load conditions.[3]

Seasonal capacity prices don't reflect seasonal reliability needs. NYISO's summer and winter capacity market demand curves are not designed to value capacity according to each season's reliability risk. Instead, the demand curves are designed to allocate capacity payments over summer and winter months based on the amount of installed capacity. This has the perverse result that, if reliability risk is found to be greatest in winter, capacity payments will still be concentrated in summer (when the amount of *installed* capacity is lowest). As a result, NYISO markets will not incentivize investment in capacity that is available in the months of greatest need and may lead to premature retirement of winter-capable resources.

To address this concern, we recommend modifying the translation of the annual revenue requirement for the demand curve unit into monthly or seasonal demand curves that consider

3 See our 2021 State of the NYISO Markets recommendation #2021-4a.

reliability value.[4] Under this approach, a portion of the value allocated to each month's demand curve would be proportionate to that month's share of LOLE in MARS. This would allow monthly capacity prices to adjust over time to reflect the timing of reliability needs. Minimum demand curve values should be used for months or seasons with de minimis LOLE risk so that resources have incentives to coordinate planned outages with the NYISO year-round.

Existing capacity zones could fail to reflect reliability needs. Our analysis suggests that eastern New York (NYISO zones F through K) will collectively face higher reliability risk in winter than the NYCA as a whole. The Central East and Total East interfaces limit the ability of surplus generation in central and western New York to flow east. As a result, if winter reliability risk increases, resources in Zone F will be paid a NYCA capacity price that does not reflect their ability to reduce winter reliability risk in eastern New York. This would send inadequate incentives for generators in Zone F to invest in or maintain dual fuel capability or firm gas arrangements and could lead to premature retirements of winter-capable units.

The NYISO has a process for creating new capacity zones, but this process is conducting only once every four years, and it requires the NYISO to identify a highway deliverability constraint under peak summer demand conditions. Hence, the existing rules will not create a new capacity zone for a winter reliability need.

To address this concern, we recommend adopting implementing locational marginal pricing of capacity ("C-LMP").[5] This recommendation would eliminate existing capacity market localities and demand curves and instead set prices based on the marginal reliability improvement (MRI) calculated at each location in MARS. This approach would be more flexible than the current capacity market zone creation process at adapting to changes in the location of reliability needs and setting prices accordingly. Alternatively, the NYISO could develop new criteria for creating a new capacity zone, but this would still require significant tariff and market changes.

D. Comments on Transmission Security Analysis

The RNA finds that reliability margins are much tighter in the transmission security analysis than the resource adequacy analysis. In particular, the base case transmission security analysis finds a margin of just 54 MW in Zone J in 2025, rising to 780 MW in 2026. By contrast, the base case resource adequacy analysis finds a margin of 925 MW in Zone J, rising to 2,125 MW in 2026. These approaches use different methodologies and are not intended to produce identical results. However, key differences in the treatment of certain resources cause transmission security analysis to be stricter in some circumstances. As a result, Locational Capacity Requirements (LCRs) are likely to be set based on the Transmission Security Limit (TSL) methodology as TSLs exceed the LCRs determined using GE-MARS. This will cause the following market problems:

4 See our 2021 State of the NYISO Markets recommendation #2019-4.

5 See our 2021 State of the NYISO Markets recommendation #2013-1c.

- Consumer costs will increase because the capacity market will effectively ignore the contributions of certain resources by adding their capacity back to the LCR; and
- The capacity market will send inefficient signals for investment because some resource types will be paid excessively compared to the value they are assumed to provide in the transmission security analysis.

To address these issues, we recommend: (a) reviewing the transmission security and resource adequacy analyses to ensure they use reasonable assumptions, and (b) compensating resources based on their contribution to transmission security if transmission security needs are more binding (i.e., if LCRs are set by the TSL methodology). Both of these approaches would improve the alignment of market signals with the NYISO's assessment of its reliability needs.

The following resource types are modeled in a manner that makes them provide substantial resource adequacy value while providing little or no value in the transmission security analysis:

1. Special Case Resources (SCRs)

NYISO assumes that demand response providers in the Special Case Resource (SCR) program provide 0 MW in the transmission security analysis because the transmission security analysis only considers resources available under normal conditions. NYISO similarly assumes that SCRs do not provide any benefit towards satisfying LCRs when the LCR is set based on the TSL methodology in the capacity market.[6] However, SCRs are included in GE-MARS and are eligible to receive capacity payments (currently valued at 90 percent of the SCR's registered capacity).

If the capacity of SCRs remains discounted in the transmission security analysis compared to resource adequacy analysis, NYISO should reflect this in the capacity market by discounting payments to SCRs when they cause the LCR in their zone to increase due to transmission security considerations. For example, if the Zone J LCR is set based on the TSL for the zone and the G-J Locality LCR is not, an SCR in Zone J contributes to satisfying the G-J Locality reliability requirement but not the Zone J requirement. Therefore, it would be appropriate to pay the SCR based on the G-J Locality price rather than the Zone J price. In this type of situation, if a Zone J SCR is capable of being available under normal market operations, it will have the option to register as a Distributed Energy Resource ("DER") and continue to be paid based on the Zone J capacity price.

2. Emergency Assistance (EA)

NYISO's transmission security analysis does not assume any external imports or emergency assistance (EA) from neighboring control areas. However, GE-MARS includes external assistance as an emergency operating procedure to avoid load shedding, with a statewide limit of up to 3,500 MW. Emergency assistance is a large contributor to reliability in resource adequacy analysis. In the base case, NYCA LOLE far exceeds the 0.1 days/year criterion in all years

6 See October 4, 2022 presentation "Transmission Security Limit Calculation: 2023 LCR Study", available here.

before emergency assistance is considered.[7] The more conservative assumption of no EA in the transmission security analysis may contribute to rising TSLs or an apparent need for regulated procurements.

In some circumstances, it is safer not to assume that emergency assistance will be forthcoming – for example, EA is likely to be limited from New England during a winter cold snap, as discussed in Section C of this memo. However, it is highly conservative to assume that EA (or even economic imports not backed by UDR sales) is never available under any circumstances. NYISO should continue to evaluate the reasonableness of its assumptions regarding the amounts of emergency assistance available in the resource adequacy and transmission security analyses.

3. Large Resources

The 2022 RNA base case analysis includes the scheduled addition of the Champlain Hudson Power Express (CHPE) transmission line, which will provide 1,250 MW of capacity in summer in New York City beginning in 2026. The loss of the CHPE line will be the largest contingency in New York City once it enters service, so it is assumed to experience an outage in the base case N-1-1-0 transmission security analysis. As a result, the addition of the 1,250 MW line causes the transmission security margin in New York City to improve by only 718 MW, or 57 percent of the line's installed capacity.[8]

This result highlights how large resources that can be lost in a single contingency provide less value for reliability planning than smaller resources with the same total capacity. This effect is more pronounced in transmission security analysis than resource adequacy analysis – the addition of the 1,250 MW CHPE line causes the zonal resource adequacy margin in Zone J to increase by 1,200, or 96 percent of the line's capacity. If the Zone J LCR is set by the TSL methodology in the future, up to 532 MW of additional capacity will be procured because CHPE's accredited UCAP will exceed its effective contribution to the LCR. Hence, the capacity payments of large-contingency units should be discounted when they cause the LCR in their zone to increase due to transmission security considerations.

E. Conclusions and Recommendations

Overall, we continue to find that the NYISO markets are well-designed and generally provide efficient investment signals. However, we have concerns regarding the current market design's ability to provide efficient incentives to satisfy reliability needs in some situations. These shortcomings could lead to inefficient market outcomes and/or the need for regulated solutions. We identify the following concerns:

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7 See Figure 37 of RNA (LOLE Results by Emergency Operating Procedure Step) on page 61.

8 Prior to the inclusion of CHPE, the most limiting N-1-1-0 contingency in New York City is the loss of Ravenswood 3 followed by the loss of Mott Haven – Rainey (Q12). Following the inclusion of CHPE, the most limiting N-1-1-0 contingency is the loss of CHPE followed by Ravenswood 3. Hence, the improvement in transmission security margin from the entry of CHPE is closer to the operating limit of the Mott Haven – Rainey line than to the larger CHPE line.

- NYISO's planning studies and markets do not adequately consider winter reliability issues that may arise due to unavailability of certain resources. To address this, we make the following recommendations:
    - Improve the resource adequacy modeling and capacity accreditation of resources with limited fuel availability during peak winter conditions.[9]
        - The NYISO has indicated that it plans to evaluate this issue in 2023 in the *Modeling Improvements for Capacity Accreditation (SOM)* project. [10]
    - Implement capacity market demand curves that consider monthly or at least seasonal reliability risk.[11]
        - The NYISO has indicated that it plans to investigate ICAP Demand Curves that reflect seasonal reliability risk as part of the 2025-2029 Demand Curve Reset.[12]
    - Recognize the value of capacity east of the Central-East interface by creating a F-K Locality or by implementing C-LMP so that locational prices can accurately reflect seasonal reliability needs.[13]
- The NYISO capacity market does not provide efficient compensation when requirements are set by transmission security considerations rather than resource adequacy needs. To address this:
    - We recommend that the NYISO discount payments to SCRs and large-contingency resources when transmission security limits are binding in the capacity market.

9 See our 2021 State of the NYISO Markets recommendation #2021-4a.

10 See BPWG materials for August 25, 2022.

11 See our 2021 State of the NYISO Markets recommendation #2019-4.

12 See ICAPWG presentation *Capacity Accreditation* dated August 29, 2022, slide 24.

13 See our 2021 State of the NYISO Markets recommendation #2013-1c.