

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System
Operator, Inc.

Docket No. ER26-1431-000

PREPARED TESTIMONY AND EXHIBITS OF

ANDREW LEVITT

ON BEHALF OF

H.Q. ENERGY SERVICES (U.S.) INC. (“HQUS”)

MARCH 11, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS, JOB TITLE, AND EMPLOYER.

A: My name is Andrew Levitt. My business address is 1800 M Street SW, Suite 700, Washington, DC. I am a Senior Consultant at The Brattle Group.

Q1: PLEASE DESCRIBE YOUR AREA OF EXPERTISE

A: My expertise is in wholesale electricity markets operated by Independent System Operators (ISOs) and Regional Transmission Operators (RTOs). I focus on market design, reliability planning, operational integration of renewables and storage, and transmission policy. During my three years with Brattle, I have advised the Midcontinent Independent System Operator (MISO), the New York Independent System Operator (NYISO), the Ontario Independent Electric System Operator, and the Alberta Electric System Operator on wholesale market design reforms. I have also worked with a variety of clients engaging with those and other ISO/RTOs in market design reforms and generator operations. Prior to joining Brattle, I was employed for seven years at the PJM Interconnection, LLC (PJM), ultimately as Senior Lead Market Designer. In that role, I supported reforms to capacity, energy and ancillary services markets, and contributed to enhancements to integrate growing resource types such as wind, solar, and storage into markets, operations, and planning. A more detailed summary of my qualifications, including publications and testimony, is attached as Exhibit Brattle-1.

Q: ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A: Yes, I am sponsoring the following exhibit:

- Exhibit No. Brattle-1: CV of Andrew Levitt

II. ASSIGNMENT AND SOURCES REVIEWED

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: I was asked by counsel for H.Q. Energy Services (U.S.) Inc. (HQUS) to evaluate certain elements of the New York Independent System Operator, Inc. (NYISO) Winter Reliability Capacity Enhancements initiative, including NYISO’s proposal to implement new capacity import provisions through (1) seasonal elections for holders of Unforced Capacity Deliverability Rights (UDRs) and External-to-Rest of State Deliverability Rights (EDRs) 15 months prior to each winter season; with (2) a must-offer requirement for seasonal capacity imports and associated enforcement mechanisms.¹

I was asked to assess whether the proposed seasonal election and must-offer framework for UDRs and EDRs, as applied to system-backed cross-border capacity sales from Hydro-Québec (HQ) into NYISO—including capacity imports that would be deliverable into the New York City (Zone J) locality over the Champlain-Hudson Power Express (CHPE) transmission project—would be expected to support cost-effective, efficient, reliable, and competitive Installed Capacity (ICAP) market outcomes.

In addition, I was asked to identify and evaluate potential solutions to enhance the proposed market design in a way that meets NYISO’s stated objectives—particularly the objective of maintaining or improving the alignment between modeled seasonal reliability requirements and the actual conditions in the capacity market—while avoiding the inefficient foreclosure of seasonal and monthly capacity imports that would be valuable for New York consumers and increase NYISO reliability.

¹ New York Independent System Operator, [Winter Reliability Capacity Enhancements](#), Docket No. ER26-1431-000, submitted to the Federal Energy Regulatory Commission, February 18, 2026, pp. 5–7. (“NYISO Proposal”).

1 **Q: WHAT MATERIALS DID YOU REVIEW IN PREPARING THIS TESTIMONY?**

2 A: In preparing this testimony, I reviewed, among other things: the NYISO Proposal; the
3 Winter Reliability Capacity Enhancements Issue Discovery Report;² NYISO stakeholder
4 materials and concept papers regarding the Winter Reliability Capacity Enhancements
5 initiative; relevant provisions of the NYISO Market Administration and Control Area
6 Services Tariff and ICAP Manual;³ New York State Reliability Council (NYSRC) and
7 NYISO materials regarding the Installed Reserve Margin (IRM) study and NYISO's
8 Locality Capacity Requirement (LCR) and Transmission Security Limit (TSL) processes;
9 NYISO load and peak demand projections, including the 2025 Load & Capacity Data
10 ("Gold Book");⁴ and publicly available materials regarding CHPE and the historical
11 pattern of HQ capacity exports to NYISO and ISO New England (ISO-NE).

12 The opinions I express in this testimony are based on my review of these materials, my
13 professional experience with capacity market design and reliability planning in organized
14 wholesale markets, and the analyses in the appendix to this testimony.

15 III. SUMMARY OF FINDINGS

16 **Q: PLEASE SUMMARIZE YOUR FINDINGS**

17 A: My key findings are as follows. First, by requiring holders of UDRs/EDRs to elect fixed
18 monthly Unforced Capacity (UCAP) quantities and associated capacity import
19 commitments for the entire six-month seasonal capability period well in advance
20 (approximately fifteen months) of the start of the winter season, without providing a
21 workable monthly reconfiguration or buy-out mechanism, NYISO's proposal would
22 foreseeably cause system-backed capacity importers to adopt conservative elections based
23 on the most constrained month of a season, and based on their most conservative 15-

² NYISO, [Winter Reliability Capacity Enhancements: Issue Discovery Report](#), December 2024. ("Issue Discovery Report")

³ NYISO, [Market Services Tariff](#), updated March 2, 2026. ("NYISO Tariff"); NYISO, [Manual 04: Installed Capacity Manual](#), Version 16.0, January 29, 2026. ("ICAP Manual").

⁴ NYISO, ["Load & Capacity Data,"](#) April 2025. ("Gold Book").

1 month-ahead estimate of their net capacity position in the delivery season. This
2 effectively restricts and excludes otherwise available capacity imports from participating
3 in the NYISO capacity markets. In the case of HQUS offering capacity imports to New
4 York City from HQ's CHPE transmission line, this would significantly reduce the amount
5 of capacity available to New York in winter, especially during shoulder months when
6 additional imports are physically available and these imports would be beneficial to New
7 York.

8 Second, I find that the excluded capacity imports would increase capacity prices and
9 consumer costs and decrease efficiency. I calculate the consumer impact of this must-
10 offer obligation at \$165 million for the 2027/2028 winter season based on NYISO's
11 proposed restrictions on imported capacity from CHPE and conservative monthly capacity
12 import assumptions. The proposal would also impede efficient trading relative to sales
13 into the ISO-NE capacity market and suppress the real underlying variability in the
14 monthly price of capacity during months in which more capacity supply is available.
15 Finally, it would reduce access to the reliability value of committed monthly capacity and
16 interfere with market power mitigation objectives for large suppliers to offer all the
17 capacity they are physically capable of providing.

18 Third, I address the important concern NYISO raises regarding potential "...misalignment
19 between the proposed seasonal requirements and available supply in a delivery month."⁵
20 NYISO explains that, "[w]hen import assumptions used in the IRM setting process
21 diverge from actual imports in the Winter Capability Period, then the IRM may not
22 accurately reflect the winter resource adequacy risk."⁶ I explain how seasonal
23 requirements (used to develop the demand side of the capacity market) can be misaligned
24 with the supply side of the capacity market (which can be counterintuitive, since the
25 supply and demand sides of a market would ordinarily be quite disparate). In particular,
26 the actual reliability need that emerges in a capacity auction can be affected by the

⁵ NYISO Proposal, p. 6

⁶ Issue Discovery Report, p. 12

1 presence of large suppliers. I find that suppliers of winter capacity will not have such an
2 effect in Zone J provided they are smaller than a threshold in the 700–800 MW range.

3 Fourth, I find that mechanisms that are less restrictive than the proposed seasonal election
4 and must-offer obligation can be used to avoid misalignments that cause reliability
5 problems. I describe solutions that allow variable monthly offers capped at a size that
6 avoids a problematic misalignment in reliability needs. The cap is defined to be the level
7 at which variable monthly offers would not materially impact reliability needs (i.e., 700–
8 800 MW for Zone J). One solution allows for monthly variability by applying NYISO’s
9 proposed must-offer obligation only for UDR/EDR elections and capacity offers above
10 the size cap. The second solution would allow monthly offers above the elected quantity
11 (but below the cap) under certain circumstances. I find that one or the other of these
12 alternative solutions avoids my estimated \$165 million customer cost impact of the
13 NYISO’s proposed must-offer obligation. I further find that they improve efficiency by
14 allowing all available cost-effective supply to be offered. This additional supply is limited
15 during low-value months by higher-value opportunities in neighboring markets (which
16 also limits how much monthly capacity imports can reduce NYISO capacity market
17 prices). Meanwhile, the additional supply can provide much-needed capacity during tight
18 months (which are increasingly expected to occur during shoulder months) and periods
19 with unexpected reliability needs (e.g., unplanned large generating plant outages), thereby
20 mitigating price spikes and improving reliability.

21 Finally, I find that the alternatives can be reasonably implemented, improve the reliability
22 of NYISO’s proposal in other ways, and align with the market power mitigation construct.

IV. BACKGROUND OF SEASONAL TRADE IN THE NYISO CAPACITY MARKET

Q: PLEASE EXPLAIN NYISO’S TRANSITION FROM A SUMMER-RISK TO A WINTER-RISK SYSTEM AND ITS IMPLICATIONS FOR THE CAPACITY MARKET.

A: NYISO administers a seasonal and monthly capacity market (formally called the Installed Capacity Market) that is intended to procure sufficient capacity (denominated in unforced capacity, or UCAP) to satisfy the NYSRC-established IRM and NYISO-established locality requirements for meeting reliability needs, while allowing competitively offered supply to clear against an administratively defined demand curve. Historically, NYISO has been summer-peaking, and key elements of its capacity construct—including the annual capability year framework and many modeling assumptions—have been oriented toward summer reliability risk.⁷

From a market design standpoint, NYISO’s capacity market construct has long had an important practical feature: it allows capacity suppliers and buyers to adjust their capacity positions on a monthly basis to reflect changes in the physical capability of supply, the physical position of buyers, and the net position of importers.⁸ This monthly granularity can be particularly important for resources whose availability is inherently seasonal or variable, including demand-response resources and system-backed imports whose net capability varies widely by month and can be accurately committed only with relatively short notice. This ability to increase supply in some months without being constrained by fixed seasonal commitments can improve both efficiency (by letting the lowest-cost capacity clear) and reliability (by encouraging resources to make capacity available when they can and when doing so is valuable).

⁷ Issue Discovery Report, p. 1

⁸ NYISO Tariff, Section 5.13.3, p. 279 (“Each Monthly Auction will be conducted and solved simultaneously to purchase Unforced Capacity which may be used by an LSE toward all components of its LSE Unforced Capacity Obligation for each Obligation Period. Participation shall consist of: (i) LSEs seeking to purchase Unforced Capacity; (ii) any other entity seeking to purchase Unforced Capacity; (iii) qualified Installed Capacity Suppliers; and (iv) any other entity that owns excess Unforced Capacity.”)

1 NYISO uses distinct capacity market demand curves for the summer and winter capability
2 periods.⁹ In broad terms, the current winter demand curve is derived from the summer
3 demand curve through application of administratively specified parameters. This approach
4 translates a historically summer-centric reliability requirement into a winter procurement
5 target without conducting a full season-specific reliability study for each season.

6 NYISO and stakeholders have increasingly recognized, however, that electrification
7 trends and rising winter loads—driven by, among other factors, the growth in electric
8 heating, transportation, and other electrified end uses—are likely to increase winter-
9 specific reliability challenges.¹⁰ Even while NYISO does not expect to be persistently
10 winter-peaking until late in the 2030s, winter stress events caused by fuel constraints can
11 drive an increase in the winter distribution of reliability risk well before a persistent
12 “winter peaking” crossover occurs on the system.¹¹

13 In response to these expected changes, NYISO has now proposed a Winter Reliability
14 Capacity Enhancements framework that includes: (i) establishing winter demand curves
15 based on summer reliability needs and available winter capacity supply; (ii) requiring
16 seasonal elections for holders of UDRs and EDRs for capacity imports (15 months prior
17 to each winter season), coupled with (iii) a Must-Offer Requirement and financial
18 consequences for failure to offer the elected capacity in each month of the season.¹² The
19 UDR/EDR-related design choice is the focus of this testimony, specifically the proposal
20 to require holders of UDR/EDR to elect to offer fixed season-long monthly UCAP
21 quantities and capacity sales commitments over a year in advance of the winter season
22 and to treat those offered quantities as fixed obligations across all six winter months,
23 without the ability to participate in monthly auctions to adjust the elected seasonal
24 capacity import levels.

⁹ NYISO Tariff, Section 5.14.1.2.2.3, pp. 295–297

¹⁰ Issue Discovery Report, p. 4.

¹¹ *Ibid*, pp. 5–6; Gold Book, p. 19.

¹² NYISO Proposal, pp. 3–4, 7. The election is made in August prior to the start of the applicable Capable Year, which begins in June, thus making it 15 months before the corresponding November (the first month of the winter capability season) NYISO Proposal, pp. 5–7.

1 **Q: PLEASE EXPLAIN HOW SYSTEM-BACKED CROSS-BORDER CAPACITY**
2 **TRADE WITH NYISO WORKS AND HOW IT ENHANCES EFFICIENCY**
3 **TODAY.**

4 A: A capacity sale from system-backed imports from a neighboring region (called a Control
5 Area System Resource or CASR in NYISO) is a form of interregional capacity transaction
6 in which the net excess capacity of an external system (such as HQ) is sold into a
7 neighboring capacity market (such as NYISO or ISO-NE).¹³ Unlike unit-specific imports
8 that depend on the deliverability and performance of a particular generating unit, system-
9 backed capacity reflects the aggregate capability of an entire control area to export
10 reliably, subject to transmission capability and the exporting system's own net resource
11 adequacy position.

12 System-backed cross-border capacity trade can be a cost-effective way to meet resource
13 adequacy needs because it takes advantage of interregional diversity in load shapes,
14 outage patterns, and the different timing of seasonal peak loads.¹⁴ For example, a system
15 that is predominantly winter-peaking may have excess capacity available during summer
16 months that can be sold to a neighboring summer-peaking system, and vice versa. When
17 such diversity exists, cross-border trades can reduce the total amount of capacity that must
18 be procured across the combined footprint, lowering overall costs while maintaining
19 reliability. Even two winter-peaking systems will benefit from interregional diversity
20 because peak loads and resource availability will generally not perfectly coincide on a
21 daily or hourly basis.

22 A CASR has two practical features relevant to NYISO's proposal: the first is that the
23 quantity of capacity available for export in a given month or season generally cannot be

¹³ NYISO Tariff, section 2.3, p.12. ("Control Area System Resource: A set of Resources owned or controlled by an entity within a Control Area that also is the operator of such Control Area. Entities supplying Unforced Capacity using Control Area System Resources will not designate particular Resources as the suppliers of Unforced Capacity." It is my understanding that the CASR designation for Hydro-Québec's resources was created early in the NYISO's history, in recognition of pre-NYISO legacy contracts between New York and Québec.)

¹⁴ Johannes P. Pfeifenberger, Kathleen Spees, Kevin Carden, and Nick Wintermantel, [Resource Adequacy Requirements: Reliability and Economic Implications](#), prepared for FERC, September 2013, p. 57.

1 finalized far in advance. The second is that the quantity of capacity available to trade
2 varies significantly by month.

3 The capability of a system such as HQ to export capacity to New York is uncertain due to
4 many factors, including changes in planned resource availability, unexpected extended
5 outages, updated load forecasts, and changes in demand response enrollment or
6 performance expectations.¹⁵ Firm sales to external control areas other than New York are
7 also taken into consideration.¹⁶

8 The excess capacity available for sale from HQ varies monthly primarily because demand
9 for capacity is heavily dependent on weather. In winter, demand peaks in December,
10 January, and February, and so neighboring systems are likely to have less excess capacity
11 during those months. In systems with substantial weather-dependent supply such as wind
12 power, solar power, demand response, and run-of-river hydropower with minimal
13 pondage, capacity supply can also vary by month.

14 As a result of these two features, it is efficient to take maximum advantage of system-
15 backed capacity by providing a market mechanism to (a) allow for relatively short-notice
16 commitment of capacity, and (b) take advantage of a capacity supply profile that varies by
17 month. A short-notice commitment can be accomplished through either (i) monthly
18 commitments made close to the delivery month capability (as is currently the case in
19 NYISO), or (ii) seasonal or annual forward commitments paired with a mechanism to buy
20 back or reconfigure some of those commitments on a monthly basis (as is available in
21 some other organized markets, such as ISO-NE).

22 Accommodation of a variable monthly profile can be achieved through various means, but
23 the simplest is to have a monthly capacity market, as is currently the case in NYISO.
24 While the current NYISO market design efficiently incorporates HQ's system-backed
25 capacity into its capacity market design, NYISO's proposed new Winter Reliability
26 framework would create significant new barriers. As currently proposed, it would require
27 a commitment to offer winter capacity more than a year in advance, with monthly

¹⁵ Prepared Testimony of Simon Bergevin, Docket No. ER26-1431-000, before the Federal Energy Regulatory Commission, March 11, 2026, pp. 6, 17–19 (“Bergevin Affidavit”).

¹⁶ Bergevin Affidavit, Section V.

1 capacity quantities fixed across the six months of each season.¹⁷ Without a short-notice
2 buy-back mechanism to reconfigure monthly positions, the proposal would therefore
3 require HQUS to formulate capacity commitments using conservative estimates of both
4 the future evolution of their net capacity position, and the lowest of their monthly
5 availabilities across the season. The proposal would therefore inefficiently exclude short-
6 term monthly capacity sales that would, in turn, increase the cost of meeting New York
7 City and NYISO resource adequacy requirements.

8 **Q: PLEASE DESCRIBE HYDRO-QUÉBEC'S HISTORICAL AND EXPECTED**
9 **CAPACITY EXPORTS TO NYISO AND NEIGHBORING MARKETS.**

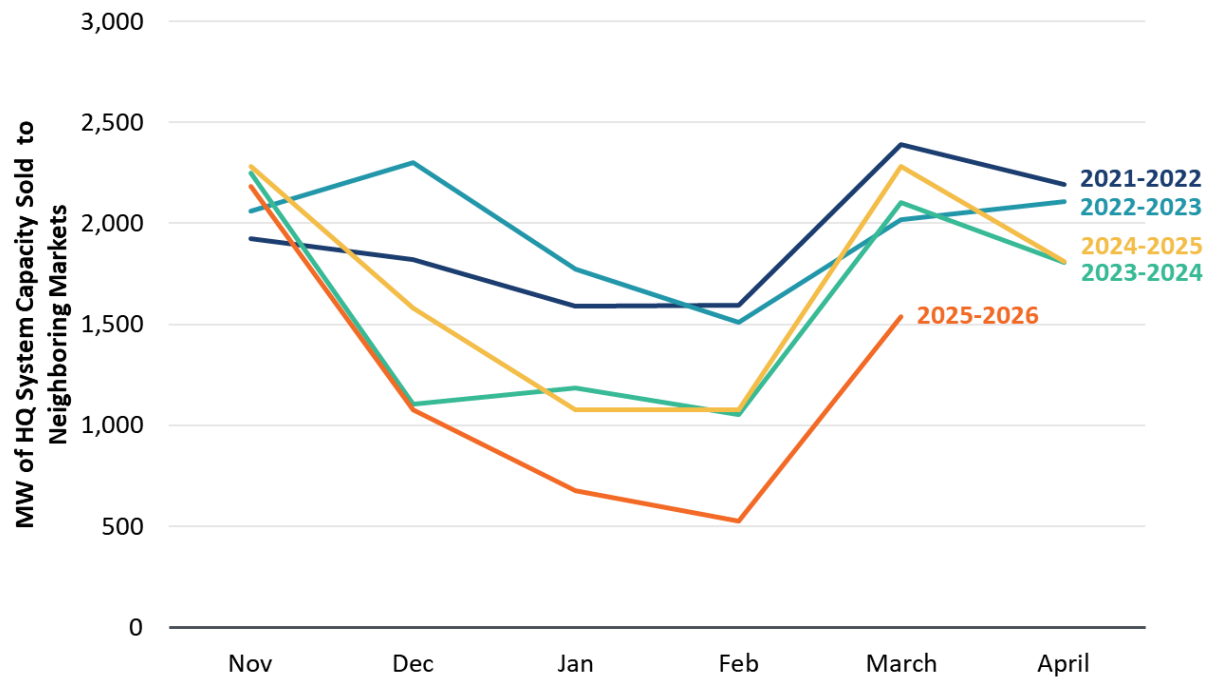
10 A: HQUS has historically supplied substantial winter capacity to both NYISO and ISO-NE,
11 consistent with the broader economic logic of interregional exchange.¹⁸ These historical
12 transactions demonstrate that system-backed capacity imports can provide meaningful
13 resource adequacy value to New York.

14 Figure 1 below summarizes the recent winter season capacity capability from the HQ
15 system available for offering into neighboring region capacity markets, including ISO-
16 NE, Ontario Independent Electricity System Operator, and NYISO. This illustrates the
17 magnitude of capacity capability in peak months (as low as 500 MW) and the variability
18 in monthly quantities that typically occur within a winter season (well over 2,000 MW). It
19 also shows that peak-month capacity is declining, with a drop of over 500 MW between
20 the prior and current winter seasons. In the near future, the peak-month available capacity
21 from all of HQ may be zero MW, despite a shoulder month availability of potentially
22 more than 1,000 MW.

¹⁷ NYISO Proposal, pp. 5–7.

¹⁸ Bergevin Affidavit, Section IV.

FIGURE 1. TOTAL MONTHLY WINTER CAPABILITY (IN ICAP MW) OF HYDRO-QUEBEC SYSTEM SOLD TO NEIGHBORING MARKETS BETWEEN NOVEMBER 2021 AND MARCH 2026.



Source: Bergevin Affidavit, Section IV, Table 1, pp. 15 – 16.

Looking forward, HQ will be able to deliver capacity to New York City (Zone J) via the new 1,250 MW CHPE transmission line. As a controllable high-voltage, direct-current (HVDC) transmission interface, CHPE is expected to deliver firm capacity into Zone J during the summer months.¹⁹ In addition, it is capable of delivering winter capacity based on available net capacity on the HQ system on a month-to-month basis. Given the anticipated growth in the value of winter capacity over time, the variable winter sales over this interface will be an increasingly important potential source of competitive supply for the Zone J capacity market to support winter reliability and reduce capacity costs in New York City.

The potential winter capacity imports enabled by CHPE are large relative to the scale of the Zone J market. CHPE could in theory sell 1,250 MW of ICAP into Zone J, compared to a projected Zone J winter peak demand of approximately 8,000 MW (and a local

¹⁹ New York State Department of Public Service, [Order Approving Contracts for the Purchase of Tier 4 Renewable Energy Certificates](#), Case No. 15-E-0302, April 14, 2022, pp. 61–64.

transmission security requirement of approximately 5,000 MW) later this decade.²⁰

However, even capacity imports well below CHPE's maximum capability will make a material impact on capacity market outcomes in New York City, affecting both reliability and capacity costs for New York City customers.

Accordingly, the effect of the NYISO proposal to materially constrain monthly winter capacity sales from HQ into Zone J through CHPE would have important implications for winter-season capacity market outcomes and New York City customers.

Q: PLEASE EXPLAIN HOW HYDRO-QUÉBEC CAPACITY IMPORTS ARE ELECTED AND OFFERED UNDER NYISO'S CURRENT CAPACITY MARKET DESIGN.

A: NYISO's current rules require holders of UDRs and EDRs to "elect" a fixed monthly quantity of potential NYISO capacity imports for a capability period.²¹ This period is currently one year. This election is made in August prior to the start of the winter capability period.²² Any UDR/EDR capability not elected for sale must be "returned" to NYISO, which may then be reflected as freely available capability in the resource adequacy studies for New York, reducing the capacity procurement requirement. HQUS has historically elected to retain its EDRs and UDRs so that various amounts of capacity can be sold into NYISO on a monthly basis.²³

Under the current NYISO capacity market design, HQUS has been able to import capacity to NYISO from HQ via existing ties with sufficient flexibility to reflect the timing with which its available capability becomes known.²⁴ We understand that this information becomes available only in the months immediately prior to the start of the winter season, for example, when the megawatt requirement for winter capacity is finalized under the

²⁰ Gold Book, Table I-5, p. 28, p. 28; NYISO, [Short-Term Assessment of Reliability: 2025 Quarter 4](#), January 13, 2026, Figure 46, p. 75.

²¹ ICAP Manual, section 4.14.3, pp. 148 – 150.

²² *Ibid.*

²³ Bergevin Affidavit, p. 5.

²⁴ Namely, the Chateauguay-Massena intertie and the Dennison intertie.

1 Northeast Power Coordinating Council (NPCC) comprehensive review of resource
2 adequacy for the Quebec Control Area.²⁵ In practice, this has allowed HQUS to offer into
3 the ISO-NE and NYISO capacity markets nearly the full amount of available monthly HQ
4 system capacity. This timing feature of the current NYISO capacity market design is
5 economically important because it allows New York consumers to benefit from
6 additional, competitively priced capacity imports when the capacity is known to be
7 available physically in the HQ system.

8 The timing of the current NYISO monthly capacity sales construct is also compatible with
9 ISO-NE's monthly capacity market participation framework. ISO-NE currently features a
10 3-years-forward capacity auction followed by annual and monthly reconfiguration
11 auctions, each of which runs prior to the NYISO monthly spot auction for the same
12 delivery month.²⁶ This three-stage approach (first participation in New England's forward
13 capacity market, then in New England's monthly reconfiguration, and finally in NYISO's
14 spot auction) allows HQ system capacity to be sold into ISO-NE's forward capacity
15 market but, if market conditions change such that capacity is more efficiently sold to
16 NYISO (or somewhere else), it can be bought back in the ISO-NE monthly
17 reconfiguration auction. Thus, because HQUS as the seller can adjust quantities in both
18 markets closer to each delivery month, system-backed capacity can be allocated
19 efficiently between NYISO and ISO-NE based on relative capacity prices and relative
20 scarcity of supply, thereby ensuring that the region with the higher marginal reliability
21 need is able to attract the available supply. Such cross-market arbitrage supports efficient
22 price formation and is consistent with objectives to promote competitive market
23 outcomes. It also can tend to drive price convergence among the monthly markets to the
24 extent sufficient transfer capability is available.

²⁵ Bergevin Affidavit, Section V, pages 17.

²⁶ The ISO-NE monthly reconfiguration auctions are held approximately 6 weeks prior to the delivery month, whereas the NYISO spot auctions are held a few days before the delivery month.

1 **Q: PLEASE EXPLAIN HOW NYISO AND NYSRC RELIABILITY STUDIES SET**
2 **STATEWIDE AND LOCAL CAPACITY REQUIREMENTS.**

3 A: Reliability studies are used to identify the reliability needs that set the capacity
4 requirement for NYISO and its localities. Chief among these is the Installed Reserve
5 Margin (IRM) study, specified by the NYSRC and executed by NYISO, which sets the
6 state-wide capacity requirement. The other reliability studies are those used to calculate
7 Transmission Security Limit (TSL) Floors and Locality Capacity Requirements (LCRs)
8 for setting minimum capacity requirements in localities.

9 The NYISO capacity market construct reflects two related but distinct reliability
10 objectives: (1) resource adequacy (RA), which is generally measured through loss-of-load
11 expectation (LOLE) studies underlying the NYSRC IRM, and (2) transmission security
12 (TS), which reflects the ability to meet load within localities under contingency
13 conditions.²⁷ NYISO uses the Multi-Area Reliability Simulation (MARS) modeling tool
14 to calculate capacity requirements for meeting resource adequacy in the IRM study and in
15 the LCR study. NYISO also conducts transmission security assessments that produce
16 Transmission Security Limits and related “TSL Floors” that constrain the extent to which
17 a locality can rely on imports to satisfy its capacity requirement. The LCR study
18 incorporates TSL Floors to establish a capacity requirement for individual NYISO
19 localities (such as Zone J) that reflects the more constraining of the local resource
20 adequacy requirements or transmission security requirements.

21 In Zone J, the TSL Floor is currently more constraining than the local resource adequacy
22 requirement. It appears that NYISO does not model returned UDR capability in the TSL

²⁷ In its localities, the NYISO capacity market meets the more restrictive of the resource adequacy need or the transmission security need. Resource adequacy is for meeting the 1-in-10 loss-of-load-event target for minimizing regional load shed during emergency conditions of high load or load resource availability. The reliability studies for resource adequacy use the GE MARS tool in the IRM study and the LCR Optimizer. Meanwhile, transmission security is for ensuring enough zonal supply and transmission import capability to avoid excessive imports that would overload transmission lines at the zonal interface. For transmission security, the core reliability study is the Locality Bulk Power Transmission Capability study, which models power flows of a scenario without the two largest transmission and/or generation facilities serving zonal load during normal peak conditions. Next, the TSL Floor is calculated for use in the capacity market (technically as an input to the LCR Optimizer). The TSL Floor takes as input the result of the foregoing transmission study as well as zonal peak load, add-backs for certain resources, and other adjustments.

Floor studies,²⁸ which means that unreturned UDR MW are not counted towards meeting reliability needs in Zone J.

V. ASSESSMENT OF THE NYISO PROPOSAL

Q: PLEASE SUMMARIZE NYISO’S WINTER RELIABILITY CAPACITY ENHANCEMENTS PROPOSAL, INCLUDING THE SEASONAL ELECTION AND MUST-OFFER FRAMEWORK.

A: I contextualize relevant aspects of the NYISO proposal, and show that, even when recognizing the need to avoid reliability challenges associated with potential misalignments between the capacity auction and the reliability studies, imposing a must-offer capacity obligation for all UDR/EDR sources is unnecessary below a certain size threshold.

NYISO proposes to require separate summer and winter seasonal elections by holders of UDRs and EDRs, broadly following the existing annual election process. These two seasonal elections would be made at the same time, such that the winter election needs to be made 15 months ahead of the start of the winter season.²⁹ As described above, today the UDR/EDR election only acts as a cap on capacity offers from sellers with UDRs, who can then offer capacity each month according to their capability (subject to the must-offer obligations of existing market power mitigation provisions). By contrast, under the new NYISO proposal, a seller with UDRs would be obligated to offer capacity equal to the elected UDR/EDR quantity for all six months of the Winter Capability Period. The seller would also be precluded from participating in monthly capacity auctions with any available capacity in excess of the elected seasonal quantity.

²⁸ Provision of emergency assistance for a TSL Floor would be inconsistent with the principle that transmission security cases study normal conditions (e.g., using normal line ratings and typical peak load). NYISO does appear to follow this approach: for example, the UDRs for the Hudson Transmission Project HVDC line, which does not sell capacity due to expired Capacity Resource Interconnection Service, do not appear in the Transmission Capability Report (NYISO, [2025-26 Locality Bulk Power Transmission Capability Report](#)), and are not a factor in reducing the TSL Floor (NYISO, [Locational Minimum Installed Capacity Requirements Study](#))

²⁹ See footnote 12.

1 Sellers that fail to meet the proposed must-offer obligation would face a substantial
2 penalty. The penalty rate is 1.5 times the spot capacity price, and the quantity is six times
3 the largest shortfall in any one month of the season.³⁰ Importantly, NYISO has not
4 proposed a mechanism to compensate sellers for the opportunity cost associated with the
5 forward commitment, nor a new buy-back mechanism to allow for a monthly
6 reconfiguration of the commitment based on market conditions and available system
7 capacity.

8 NYISO has indicated that the purpose of these proposed seasonal elections is to provide
9 more accurate seasonal inputs that can then be reflected in the NYSRC IRM study and
10 other reliability studies used for ensuring reliability across NYISO.³¹

11 Improving alignment between the assumptions embedded in the reliability studies and the
12 supply that will be made available in the ICAP market is a reasonable objective for
13 achieving reliability and efficiency.³² The NYISO Issue Discovery Report notes that
14 “[w]hen import assumptions used in the IRM setting process diverge from actual imports
15 in the Winter Capability Period, then the IRM may not accurately reflect the winter

³⁰ NYISO Proposal, proposed tariff language, Section 5.12.12.4, p. 114 (“If the holder of an External UDR or EDR fails to offer or certify UCAP associated with an External UDR or EDR that has not been returned to the NYCA in any ICAP Spot Market Auction during the subject Capability Period, it shall pay the ISO an amount for all months of the subject Capability Period equal to the product of (i) 1.5 times the applicable ICAP Spot Market Auction price and (ii) the quantity by which the UCAP associated with the given External UDR or EDR that has not been returned to the NYCA exceeds the minimum amount of UCAP associated with the given External UDR or EDR that has not been returned to the NYCA that is offered or certified during any month of the subject Capability Period.”); NYISO, [Winter Reliability Capacity Enhancements: Market Design Update and Review of Additional Proposed Tariff Revisions](#), presented to ICAP Working Group, October 14, 2025, p. 25.

³¹ NYISO, [Winter Reliability Capacity Enhancements](#), November 12, 2025, p. 11. (“These proposed seasonal election values aim to provide more accurate input of available capacity in the applicable season that can be reflected in the New York State Reliability Council’s (NYSRC) Installed Reserve Margin (IRM) study.”)

³² As noted in the Summary of Conclusions section above, the NYISO proposes to set the winter capacity requirement at the level of winter ICAP available in its reliability model, which is distinct from and higher than the winter reliability requirement. Therefore, by construction, an extra MW of winter capacity supply in the model results in a commensurate increase in winter capacity demand. The quantity of capacity required in the proposed winter demand curve (set by winter capacity supply in the model) cannot be aligned with supply in a month’s auction unless only modeled supply is allowed to offer, and all modeled supply is obligated to offer. This would seem to lock the auction results at the time of the reliability model. I do not address the merits of this approach, nor of aligning the auction with the proposed non-reliability-based capacity requirement and instead focus here on the value of aligning the reliability needs identified in the model with the reliability needs procured in the capacity auction.

resource adequacy risk.”³³ The IRM (and other reliability studies) provide inputs to the demand curve for capacity, which in principle is primarily a function of peak demand.

Q: HOW COULD MODELING OF IMPORTED CAPACITY SUPPLY IMPACT THE ACCURACY OF THE RELIABILITY MODELS IN SETTING CAPACITY DEMAND?

A: An individual supplier cannot change the nature of demand, and most suppliers do not affect the quantity of capacity that is needed to meet reliability needs. Accordingly, the reliability model results are not sensitive to the presence or absence of most individual suppliers or resources. However, in limited cases, a large supplier can change the quantity of capacity needed for reliability. This happens for (a) a limited-capability resource that shifts when periods of scarcity risk happen (such as a large solar farm or fuel-constrained gas generator); (b) a very large source of supply for which the NYISO UCAP accreditation overestimates the reliability value (ultimately accounted for via a higher UCAP requirement);³⁴ and (c) a UDR/EDR for which declining to offer can accompany a “return” of the interface to NYISO, which will in turn be counted on in reliability modeling as a “free” emergency-assistance benefit that reduces the need for capacity.³⁵

The first effect (which I refer to as the “limited capability effect”) emerges from hourly resource adequacy models such as MARS. Examples include large energy storage resources, thermal units without secure fuel supply, wind farms, and solar farms. To illustrate this example, consider a large solar farm that displaces a smaller fossil generator in the capacity mix. In that case, some reliability risk could shift from summer afternoons into the evening and into the winter, which would lower the requirement for UCAP

³³ Issue Discovery Report, p. 12

³⁴ This overestimation effect normally is reflected in a higher demand curve, as follows: the translation from an ICAP requirement to a UCAP requirement uses the accredited UCAP value of the units in the IRM and LCR studies which, if higher than their incremental impact on reliability, will result in a higher UCAP requirement. ICAP Manual, Section 5.5, pp. 166–170.

³⁵ We do not address the case of a supplier affecting the capacity requirement under NYISO’s proposal to set the demand for winter capacity equal to the supply of winter capacity.

1 capacity since demand is lower in those periods. In this case, the unit would need to be
2 large enough to have a material effect on such scarcity risk profiles.

3 The second effect (which I refer to as the “large unit effect”) can be exemplified by the
4 largest fossil generator in New York City (approximately 1,000 MW),³⁶ as well as CHPE
5 when it is used to sell more than a material threshold quantity of capacity (e.g., more than
6 700–800 MW). In each of these cases, while the source would make a net contribution to
7 reliability, this contribution would be lower than their accreditation. In order to maintain
8 reliability under this circumstance, the NYISO market construct increases the capacity
9 requirement to compensate.³⁷ For resource adequacy, the large unit effect happens
10 because a forced outage of such a large source would cause a unique loss of supply
11 availability that itself can drive a reliability impact in the resource adequacy modeling.³⁸
12 For transmission security, it is because addition of a large unit poses a new large
13 contingency that has the net effect of improving the transmission security margin in
14 planning cases by less than its ICAP. In both cases, I refer to the size threshold where this
15 effect becomes significant the “large unit size threshold”.

16 Because CHPE sells in Zone J, which is expected to be constrained by transmission
17 security limits for the foreseeable future, the limited capability effect does not apply
18 (since it is a resource adequacy effect. Further, for the large-unit effect, the transmission-
19 security-based large unit size threshold is the relevant factor. For Zone J, this limit is
20 likely to be approximately 700–800 MW.³⁹ Based on my reading of the available

³⁶ NYISO has reported that the two largest generator loss contingencies in Zone J are Ravenswood 3 and the 608 MW Bayonne Units. NYISO, [Appendices: 2022 Reliability Needs Assessment \(RNA\)](#), November 15, 2022, p. 148. (Note that Mott Haven-Rainey (Q12) 345 kV as well as Sprain Brook-W. 49th St. 345 kV M51 and M52 are transmission loss contingencies.

³⁷ See footnote 34

³⁸ For example, ten 100-MW units are extremely unlikely to be in forced outage at the same time, and so the loss of their aggregate 1,000 MW of supply effectively never occurs in the reliability model. That is, their aggregate availability is always well above zero. By contrast, a single 1,000 MW unit occasionally experiences a forced outage, which does result in all 1,000 MW becoming unavailable.

³⁹ Without CHPE, the two largest contingencies are Ravenswood 3 (approximately 980 MW) and the transmission line segment Dunwoodie-Mott Haven (72) 345 kV (approximately 785 MW normal rating. See NYISO, [2020 Comprehensive Area Transmission Review \(ATR\) Overview](#), March 4, 2021, p. 19; NYISO, [2026-27 Locality Bulk Power Transmission Capability Report](#), pp.7–8. See also Potomac Economics, [MMU Comments on 2022 RNA](#), October 17, 2022, p. 14. (“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

1 materials, the large unit issue appears to be what NYISO is mostly concerned with
2 (although I note that NYISO has not offered substantial detail, other than to cite potential
3 reliability concerns in the Issue Paper and in stakeholder materials).⁴⁰

4 For the third effect (the “UDR/EDR return effect”), alignment with capacity market
5 conditions is assured under current rules because the seller that returned the UDR/EDR
6 cannot sell capacity corresponding to the returned MW. Further, there would not be an
7 alignment issue for CHPE even if those MWs were offered, since the NYSRC has
8 proposed modeling CHPE at zero MW in winter whether or not UDRs are returned, and
9 since returned UDRs are not included in TSL studies.⁴¹ For these reasons, I do not further
10 discuss potential misalignments related to this effect.

11 Because of the limited capability effect and the large unit effect, reliability studies and the
12 demand curves derived from them will be inaccurate (a) if the modeled fleet of
13 renewables and fuel-constrained units is significantly different from actual spot capacity
14 market conditions, or (b) if a unit offers more than the large unit size threshold into
15 monthly auctions despite not being modeled (or were modeled but did not offer).

16 Therefore, the risk of such misalignment can be reduced by imposing a requirement to
17 make binding commitments prior to reliability analysis for suppliers of (a) large limited-
18 capability resources and (b) units, possibly including HQ imports using the 1,250 MW
19 CHPE, that can offer more than the 700–800 MW large unit size threshold.

margin in New York City to improve by only 718 MW, or 57 percent of the line’s installed capacity...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.” Note that Mott Haven-Rainey also has a 785 MW rating.)

⁴⁰ Issue Discovery Report, p. 12; NYISO, [Winter Reliability Capacity Enhancements: Concept Proposal](#), July 29, 2025, p. 10 (“UDRs and EDRs that elect to participate in the ICAP market, but do not offer capacity, can create a misalignment between the proposed seasonal requirements and available supply in a delivery month... this misalignment can result in prices that are not reflective of reliability needs.”).

⁴¹ NYISO, [Champlain Hudson Power Express \(CHPE\) and Fuel Availability Constraints – 2026-2027 Installed Reserve Margin \(IRM\) Preliminary Base Case \(PBC\) Considerations](#), July 10, 2025, p. 3.

1 **Q: DOES ACCURACY OF RELIABILITY MODELS REQUIRE A MUST-OFFER**
2 **OBLIGATION TO ENSURE ALIGNMENT?**

3 A: No. In light of the foregoing, alignment between the reliability models and the actual
4 reliability need can be achieved by capping offers from unmodeled single sources at the
5 700–800 MW large unit size threshold. Therefore, even when recognizing the need to
6 avoid the “large unit” challenges, it is unnecessary to require sources with a size below
7 the threshold to commit prior to when the reliability analysis is performed. In fact, given
8 there is no payment associated with the advance commitment, and no buy-out or
9 adjustment mechanism is made available, applying the large-unit restrictions to
10 participation by smaller units distorts otherwise efficient market outcomes.

11 **Q: DOES THE NYISO PROPOSAL TAKE A TARGETED APPROACH TO**
12 **AVOIDING MISALIGNMENTS BY DIFFERENTIATING LARGE UDRS/EDRS?**

13 A: No. The NYISO’s proposed seasonal election mechanism does not differentiate among
14 small versus large UDRs/EDRs, even though presence or absence of small sources in the
15 spot market would not be expected to affect the overall reliability need and associated
16 demand for capacity (i.e., does not raise the “large unit” concern discussed above).
17 Further, the proposal does not allow for a month-by-month advance commitment rule but
18 rather requires fixed monthly UCAP quantities over the six consecutive months of each
19 season.

20 NYISO’s proposed structure has particularly strong potential to distort supply from a
21 CASR over UDRs/EDRs (such as the HQ CASR that I understand will be sold using the
22 CHPE UDRs and the EDRs at the Dennison intertie), because the physical and
23 commercial realities of system-backed capacity sales do not align with a long-lead
24 monthly election that is fixed across all months of a season.

25 NYISO has indicated that the purpose of the must-offer obligation is to avoid
26 misalignment between the seasonal capacity requirement and the available supply in a
27 delivery month.⁴² However, as I discuss above, the need for capacity to ensure reliability

⁴² NYISO, [Winter Reliability Capacity Enhancements: Concept Proposal](#), July 29, 2025, p. 10.

1 is in the first instance a function of demand for power, not the supply of resources, and
2 only in exceptional circumstances (i.e., participation of resources larger than 700–800
3 MW) does the reliability need change with presence or type of the specific sources of
4 supply. Capacity imports over CHPE would not affect the level New York reliability
5 needs if the quantity of imports offered were *below* the 700–800 MW large unit size
6 threshold. In other words, individual imports below the 700–800 MW large unit size
7 threshold would not affect the reliability need in NYISO, so would not need to be
8 identified before the reliability studies are undertaken to determine these needs.

9 **Q: WHAT IMPACTS WOULD THE NYISO PROPOSAL HAVE ON HYDRO-**
10 **QUÉBEC’S ABILITY TO EXPORT CAPACITY TO NYISO (INCLUDING VIA**
11 **CHPE INTO ZONE J)?**

12 A: As HQUS notes in the testimony of Simon Bergevin, HQ does not know fifteen months
13 prior to each winter delivery season how much capacity will be available for export
14 during that winter season. In particular, HQ will not know how much capacity it will have
15 available during the peak winter months of December, January, and February.⁴³ The HQ
16 system’s surplus capability in a month depends on load, generation conditions and
17 maintenance schedules, demand response procurement, and firm commitments in other
18 external control areas. As Mr. Bergevin testifies, HQ typically only has sufficiently
19 dependable information about winter export capability by the fall preceding a winter
20 season. In addition, HQUS does not have a fixed amount of capacity that is available for
21 export at a constant level across all six winter months. As shown in Figure 1 above, HQ
22 has greater available capacity in shoulder months than in peak winter months, which is
23 due to milder weather and lower weather-driven load, operational constraints, and system
24 conditions.

25 Under NYISO’s current capacity market design, this month-to-month variability can be
26 reflected in monthly capacity offers. Under NYISO’s proposal, by contrast, HQUS would
27 effectively need to identify the lowest capacity quantity that it could offer in any month of

⁴³ Bergevin Affidavit, Section V, pp. 18–19.

1 the winter season, 15 months prior to the season, and elect to offer that quantity (and no
2 more or less) for all six months of the season. In addition, the large penalty NYISO has
3 proposed for failure to offer the fixed elected quantity in any one month would create a
4 substantial barrier for electing a higher quantity than the minimum for any single month.
5 Because HQ has little certainty regarding available capacity 15 months before each winter
6 season, and significantly less capacity to sell in peak winter months than in shoulder
7 months, this would likely preclude the offer and sale of much (if any) HQUS capacity to
8 NYISO for winter seasons. In addition, because the NYSRC has proposed to model the
9 winter capability of CHPE at zero MW in all cases even if UDRs are returned (precluding
10 their value in reducing resource-adequacy-based reliability needs), and because the TSL
11 Floor studies appear not to incorporate returned UDR capability at all (precluding their
12 value in reducing transmission-security-based reliability needs), any winter reliability
13 value of imports from HQ will not be made available to NYISO customers on the demand
14 side, either.

15 Critically, the proposed Winter Reliability framework includes no provisions for monthly
16 capacity sales by UDR/EDR sellers above the level elected 15 months prior to each winter
17 season. It also does not include provisions that would allow a seller to buy out or
18 reconfigure a previously made seasonal election on a monthly basis. In my opinion, the
19 absence of any workable monthly adjustment mechanism is a central design deficiency
20 because (1) it imposes on suppliers with UDR/EDRs substantial uncertainty when locking
21 in conservative elections that are driven by peak-month constraints without any ability to
22 mitigate that uncertain through monthly adjustments, and (2) it forces such suppliers to
23 commit to offer no more than the minimum of each month's capability in a season,
24 despite a highly variable monthly capability profile. This will inefficiently exclude much
25 or all winter capacity imports from HQ, even though such capacity could be made
26 available on a monthly basis. As a result, the proposed framework will inefficiently
27 increase the cost of resource adequacy in New York and, in particular, in New York City.

28 This makes it clear that treating system-backed controllable transmission-enabled imports
29 as if they were conventional resources with a fixed and predictable capacity capability
30 across months, together with failure to provide for monthly reconfigurations, is not

1 consistent with the underlying physical and commercial attributes of these resources and
2 substantially precludes availability of valuable winter supply in New York City. The
3 proposal will therefore force a withholding of efficient short-notice capacity and increase
4 resource adequacy costs for New York consumers, without demonstrating a
5 commensurate reliability benefit.

6 **Q: WHAT IMPACTS WOULD THE NYISO PROPOSAL HAVE ON CAPACITY**
7 **MARKET EFFICIENCY AND COSTS TO NEW YORK CUSTOMERS?**

8 A: Under NYISO's proposal, HQUS would not be able to offer winter capacity from CHPE
9 into Zone J nor through the EDRs at the Dennison Intertie in a manner that reflects the
10 monthly availability of export capability. This likely would preclude the import of at least
11 several hundred megawatts of capacity that would be available from HQ during several
12 winter months. In the NYISO capacity market, which features a sloped demand curve, this
13 reduction in otherwise-available supply will increase capacity market clearing prices in
14 those months.

15 The resulting restriction would inefficiently fail to realize the resource adequacy value
16 that UDRs into New York City on CHPE—along with EDRs on Hydro Quebec's
17 Dennison line into upstate New York—can provide via monthly capacity imports during
18 the winter season. The total value that these monthly UDR/EDR capacity imports offer to
19 New York has three components. First, the incremental imports over CHPE offer resource
20 adequacy value in Zone J because they increase the amount of local capacity available to
21 meet LOLE-based resource adequacy requirements in New York City. Second, the CHPE
22 supply in Zone J provides transmission security value there by contributing to TSL-related
23 constraints, since it eases power flows into the city over the internal transmission
24 interface. Third, CHPE capacity imports offer broader NYISO resource adequacy and
25 transmission security value in the Lower Hudson locality and both CHPE and Dennison
26 imports meet resource adequacy needs in the rest of the New York Control Area (NYCA).

27 I have estimated the impact of eliminating 300 MW of HQ capacity sales during the
28 winter shoulder months (November, March, and April) in 2027/28 through CHPE. I chose
29 300 MW as a conservative estimate of how much HQUS might offer during the shoulder

month of the winter season in absence of the barriers created by NYISO’s proposed new capacity market requirements. Figure 1 above showed that January is the month with least availability (537 MW) while the shoulder months (November, March, and April) each have at least 1,500 MW of capacity available. Therefore, 300 MW is a conservative estimate of the effect of precluding monthly capacity imports from Quebec.

NYISO’s capacity-market spot auctions clear at the intersection of a sloped demand curve and the aggregated supply offers. If several hundred megawatts of competitive import supply are removed (or prevented from offering) in multiple winter months, the supply curve shifts left, resulting in a higher clearing price. These price changes would translate into higher consumer bills. I have estimated the aggregate bill impact across all consumers of this restriction relative to a baseline capacity position at equilibrium.⁴⁴ The resulting consumer bill impacts of excluding 300 MW of CHPE-enabled capacity from the monthly spot auctions in November, March, and April under NYISO’s proposal are approximately \$165 million during the 2027/28 winter season. Table 1 below shows the impact by locality. As shown, most of this impact falls on consumers in New York City (Zone J).

TABLE 1. SUMMARY OF ESTIMATED CONSUMER COST IMPACT BY LOCALITY DURING 2027/28 WINTER

Consumer Cost Impact (\$ million)				
	Zone J	G-J Locality	NYCA (Rest of State)	Total
Consumer cost w/o CHPE	\$377	\$48	\$242	\$668
Consumer cost w CHPE	\$249	\$35	\$219	\$503
Consumer cost impact	\$128	\$14	\$23	\$165

Source: see analysis in the Appendix.

While I estimated the impact for only one year, I believe the price impact and commensurate consumer cost increase would persist, because New York state is planning new entry based on centralized resource planning and procurements that are likely

⁴⁴ Because the capacity market has a linearly sloping demand curve and I model an inelastic (i.e., vertical) supply curve, the price change with the shift in capacity is not dependent on the baseline. However, the total quantity of capacity billed to customers does vary, and so the cost impact is slightly sensitive to the assumed baseline condition. With potential retirements and load growth, Zone J may be at equilibrium in our calculated year of 2027/28.

1 premised on meeting the NYISO seasonal reliability requirements (i.e., during peak
2 months). Therefore, there would be no relative increase in supply entry (and lowering of
3 overall price and costs) in response to the higher prices in shoulder months caused by
4 NYISO's proposed restrictions. Note that my calculation does not account for any
5 offsetting change in out-of-market investment payments for new entrants or retained
6 legacy units due to a change in capacity prices.

7 In addition to cost impacts, restricting CHPE-enabled capacity offers (or, for that matter,
8 EDR capacity offers) could adversely affect operational reliability. If CHPE imports are
9 not cleared and committed in NYISO's capacity market, that capacity likely will be
10 committed to other markets. In that circumstance, even if New York experiences
11 operational scarcity (such as due to the unexpected outage of a generating plant), non-
12 firm energy may not be available to support New York (since it may need to respond
13 instead to a similar condition in the neighboring market to which it has committed
14 capacity). Put another way, during extreme weather, neighboring regions may compete to
15 buy emergency energy from HQ, not just capacity. The holder of capacity rights has the
16 right to call on the energy and will likely prevail in that competition as a result. Such
17 occurrence of simultaneous operational issues in two areas is not uncharacteristic,
18 especially in winter.⁴⁵ And, simultaneous winter events may become more common in the
19 future as reserve margins tighten. The operational implication is that Zone J winter
20 reliability could be reduced relative to a counterfactual in which CHPE-enabled monthly
21 capacity imports could be made (as is possible under the existing capacity market
22 participation rules).

⁴⁵ During the day of January 25, 2026 during Winter Storm Fern, ISO-NE requested an emergency order from the Department of Energy for generators to disregard environmental permit limits. It was later extended several more days. NYISO requested a similar waiver on January 26, and deployed demand response resources. *See* U.S. Department of Energy, [Federal Power Act Section 202\(c\): ISO New England Order No. 202-26-03](#) and U.S. Department of Energy, [Federal Power Act Section 202\(c\): NYISO Order No. 202-26-08](#). *See also* Enel Group, "[Demand response in action during Winter Storm Fern](#)," February 19, 2026, accessed March 9, 2026.

1 **Q: HOW WOULD THE NYISO PROPOSAL AFFECT MARKET POWER**
2 **MITIGATION AND COMPETITIVE OUTCOMES?**

3 A: Market power mitigation aims to ensure that capacity prices reflect competitive outcomes
4 without imposing distortions that prevent efficient supply from participating. To ensure
5 HQUS does not exercise market power through physical withholding, current mitigation
6 rules require HQUS to offer (via its UDRs) all of the physical net excess capacity that is
7 actually available from the HQ system, a value that can vary monthly.⁴⁶ In order to
8 prevent economic withholding, they also limit HQUS's offers for excess system capacity
9 to no more than actual costs, including opportunity costs associated with possible exports
10 to other markets.

11 NYISO's proposed new market design poses a barrier to competitive outcomes and
12 arguably interferes with the aim of market power mitigation by restricting available
13 supply that existing NYISO rules would require to be offered. Indeed, HQUS faces an
14 apparent conflict between the existing obligation (under market power mitigation rules) to
15 offer all the supply it is capable of offering, while facing significant penalties under
16 NYISO's proposed must-offer obligation for making an election only at the level it has an
17 exceptionally high confidence it will be able to make for the entire winter season 15
18 months in advance. Section VI of the Bergevin Affidavit discusses the tension between
19 the existing market power mitigation rules and the new seasonal requirements for UDRs.
20 Legal interpretations notwithstanding, the likely net effect of NYISO's proposal is to
21 reduce supply in NYISO's capacity market.

⁴⁶ Subject to consultations with the NYISO under section 23.4.5.4 of the NYISO Market Services Tariff. *See* NYISO Tariff, Section 23.4.5.4, p. 712.

VI. AVAILABLE SOLUTIONS

Q: WHAT MODIFICATIONS TO NYISO’S PROPOSED NEW MARKET DESIGN COULD BE MADE TO MEET NYISO’S OBJECTIVES WHILE PRESERVING MONTHLY IMPORTS DURING THE WINTER SEASON?

A: I have identified two alternative approaches that would allow UDR/EDR sellers to flexibly offer variable monthly physical export capability in NYISO’s capacity market spot auctions a few days prior to the capability month, as is possible today. These alternatives use a “large unit” cap on the allowed monthly imports to address NYISO’s stated objective: maintaining alignment between the modeled need for capacity in reliability studies and the actual need for capacity to be procured in the spot market for meeting reliability needs. The alternatives are designed to preserve NYISO’s ability to conduct its IRM, LCR, and TSL analyses on their established timelines (starting about 15 months prior to each winter season), while avoiding inefficiently foreclosing monthly capacity imports and avoiding reliability impacts of such monthly imports due to misalignments.

The two approaches that would retain such flexibility of monthly sales while addressing NYISO concerns over misalignment are:

(1) Continue the status quo approach (i.e., no must-offer obligation other than the general must-offer rule in the existing market power mitigation measures) for UDR/EDR elections and allow capacity offers in monthly or spot auction up to the large unit size threshold (e.g., 700–800 MW) for Zone J. Only UDR/EDR elections above the large-unit cap would be subject to the NYISO-proposed must-offer obligation.

-- or --

(2) Allow sellers to offer capacity into monthly or spot auctions above the UDR/EDR MWs elected up to the cap defined as the large unit size threshold (provided that NYSRC and NYISO have not counted the returned UDR/EDR MWs towards meeting reliability needs through emergency assistance).⁴⁷

⁴⁷ In its MARS resource adequacy model, NYISO can account for returned (unelected) UDRs as largely available for meeting resource adequacy reliability needs by way of simulated emergency assistance. (However,

1 Under both approaches, the cap applies to the absolute quantity of monthly capacity
2 imports allowed from a single source. For example, under the second alternative, assume
3 HQUS elected 300 MW of UDRs in Zone J while NYISO had identified the large unit cap
4 of 785 MW. The cap would limit the maximum imports in a month to 785 MW, despite
5 the fact that HQUS had elected 300 MW. Under the first alternative, HQUS could not
6 elect 985 MW and then offer 285 MW but rather would face the must-offer obligation for
7 the full 985 MW (or any other elected value above the 785 MW large unit size threshold).

8 The two alternative solutions allow UDR holders to flexibly offer capacity into the
9 monthly or spot auctions, which are run just before the start of each month of the winter
10 season. But to address NYISO's potential concern regarding alignment of market
11 conditions with modeled reliability needs, such offers could not exceed the level at which
12 supply from a single source would drive misalignments relative to modeled reliability
13 needs (i.e., the large unit size threshold), which appears to be the primary source of
14 concern for NYISO).⁴⁸ This threshold would be confirmed by NYISO analysis
15 demonstrating no material effect on the reliability-based need for seasonal capacity in the
16 event that the elected capacity is offered or not.

17 Under either approach, the seller would still provide NYISO with a 15-month-ahead
18 election of its potential monthly offer quantities for a season, but those quantities could
19 later be varied across months to reflect the seller's expected month-to-month export
20 capability (and, thus, would not be binding).

NYSRC has recently decided not to account for any MW returned from CHPE in this way *see* footnote 41). By contrast, NYISO appears not to account for returned UDRs as meeting transmission security needs in the TSL Floor calculation. For example, the UDRs for the Hudson Transmission Project HVDC line, which does not sell capacity due to expired Capacity Resource Interconnection Service, are modeled as providing up to 660 MW of emergency assistance in MARS (*See* NYSRC, [NYCA IRM Requirement Study 2026–2027 Final Base Case \(FBC\) Model Assumptions Matrix](#), Attachment E5, p. 30), but the UDRs do not appear in the Transmission Capability Report (*See* NYISO, [2025-26 Locality Bulk Power Capability Report](#)) and is not a factor in reducing the TSL Floor (*See* NYISO, [Locational Minimum Installed Capacity Requirements Study](#)). Therefore, whenever the TSL Floor is the binding constraint for a locality, unreturned UDR MW are not counted towards meeting reliability needs.

⁴⁸ As discussed above, based on stakeholder materials from NYISO and on the centrality of reliability for the capacity market, we focus here on reliability alignment for setting the size cap. However, we recognize that NYISO may have other considerations.

Q: HOW DO THE TWO SOLUTIONS COMPARE ACROSS AFFORDABILITY/EFFICIENCY, RELIABILITY, IMPLEMENTATION, AND MARKET POWER MITIGATION?

A: The solutions would allow CHPE-enabled imports from HQ to be offered up to their available monthly winter capability, subject to a defined cap. As a result, both alternatives score similarly across the evaluation dimensions that are relevant to my assessment: affordability and market efficiency, reliability, implementation feasibility, and market power mitigation.

Q: HOW WOULD THE ALTERNATIVE SOLUTIONS AFFECT AFFORDABILITY AND MARKET EFFICIENCY IN NEW YORK?

A: Affordability and efficiency are core objectives of organized wholesale markets. My capacity market cost impact calculation indicates that continuing to allow flexible offers allowing CHPE-enabled capacity imports in winter months would reduce capacity market clearing prices and lower consumer costs for those months relative to NYISO's proposed must-offer obligation for UDRs. The resulting annual consumer savings of \$165 million would be expected to be realized under either alternative (based on the analysis of 300 MW of capacity imports during 3 shoulder winter months discussed above). And if, by chance, HQ capacity happened to be available in the peak winter months (December through February), the savings for New York consumers would increase commensurately. This improves affordability for consumers.

The solutions avoid barriers to market participation by HQ by allowing capability that is physically available in any given month to be offered into New York, while ensuring that such participation does not cause other distortions via the large unit effect. The two solutions thus enhance efficiency in the NYISO capacity market by facilitating the offer of all physically available capability into the capacity market. (This efficiency finding is strongest when taking as given that NYISO's capacity market demand curves reflect the incremental benefit of capacity in meeting reliability.⁴⁹) By allowing all available supply

⁴⁹ See, e.g., Potomac Economics, [2024 State of the Market Report for the New York ISO Markets](#), May 14, 2025, p. 1. ("The NYISO markets have several key features that are designed to allow the power of markets to satisfy

1 into the monthly auction, each of the two solutions yield prices that more fully reflect the
2 value of monthly capacity given variability in supply availability: months with more
3 supply naturally tend to have lower prices, and vice versa.⁵⁰ By contrast, NYISO's
4 proposal requires UDR/EDR importers to offer a uniform quantity of capacity in each
5 month, which would suppress variability in the value of monthly capacity, and the market
6 will not procure the efficient quantity of imports in each month.

7 Allowing all available supply to participate provides the efficient incentive to sell capacity
8 in months with available supply. Importers such as HQUS will stop clearing the auction
9 when the price falls below their opportunity cost of selling to a neighboring system or will
10 anticipate the lower price and commit their capacity elsewhere. With high import
11 capability, the monthly price in such months may therefore tend to equilibrate across
12 neighboring regions. This tends to create a floor for the NYISO capacity price
13 commensurate with the capacity price of neighbors.

14 Importantly, allowing all available supply to participate in NYISO's monthly capacity
15 auctions also makes that supply available in months with tight supply and high reliability
16 value. Anticipating high prices in NYISO, importers can ensure such capacity is not
17 committed to (or bought out of) neighboring markets where reliability needs are less
18 urgent and that capacity is less valuable. Without allowing for participation of capacity
19 importers, a monthly capacity auction might clear below the minimum capacity
20 requirement. This mechanism thus can substantially mitigate price spikes and improve
21 reliability for such a month. In some cases, such tightness could be due to an event on the
22 system, such as a long-duration failure of a large NYISO generator (an "ICAP Ineligible
23 Forced Outage"), which could not have been anticipated 15 months prior to the auction.⁵¹

the needs of the system efficiently, including: Capacity demand curves that reflect the value of incremental capacity to the system and provide for increased stability in market signals." While we take this as given, NYISO's proposal to set winter demand for capacity equal to winter supply for capacity (and above the winter reliability need) does raise questions about the extent to which it reflects the value of incremental capacity.)

⁵⁰ See, e.g., Mark Younger, [Aligning Capacity Risk and Willingness to Pay for Capacity](#), presented to the NYISO ICAP Working Group, March 3, 2025, p. 8. ("It makes no sense to be willing to pay the same for capacity resources in shoulder months with little risk that we would pay for capacity in months with significant risk.")

⁵¹ ICAP Ineligible Forced Outage is described in the ICAP Manual, pp. 61–64.

1 The flexibility in the solutions described above also maintains compatibility with the
2 timing of the ISO-NE reconfiguration auctions (as described in Section II.D above).
3 Relative to the NYISO proposal, this enhances the efficiency of regional resource
4 allocation. Due to higher expected capacity market prices in New York City, importing
5 winter capacity into Zone J can be valuable to HQUS and to NYISO relative to alternative
6 uses of that capacity, such as selling to ISO-NE or leaving the capacity unsold. When
7 NYISO prices appropriately reflect capacity tightness in Zone J, the market signal set by
8 these prices should be allowed to attract the available capacity to the region where it
9 provides the greatest marginal reliability value. NYISO's proposed design puts unneeded
10 constraints on this mechanism and so tends to misallocate capacity and increase total
11 system costs.

12 The two solutions therefore improve the affordability and efficiency of the NYISO
13 proposal by retaining the participation of importers in monthly capacity auctions while
14 also fully addressing the reliability modeling and alignment concern raised by NYISO in
15 its Issue Discovery Report, filing, and stakeholder processes.

16 **Q: HOW WOULD THE SOLUTIONS AFFECT RELIABILITY AND ALIGNMENT**
17 **WITH NYISO/NYSRC STUDIES?**

18 A: Ensuring reliability is the context for NYISO's Winter Reliability Capacity Enhancements
19 proposal. NYISO seeks to avoid misalignment between the reliability modeling that yields
20 the capacity requirement and the actual capacity market auction, stating that "[t]his
21 misalignment can result in prices that are not reflective of reliability needs."⁵² The

⁵² NYISO, [Winter Reliability Capacity Enhancements: Concept Proposal](#), July 29, 2025, p. 10. Note that, while the NYISO proposal is to calculate separate seasonal TSLs and LCRs (p. 16), it appears not to use the winter reliability need for setting the winter capacity requirement (which anchors the winter capacity market demand curve). Rather, NYISO proposes a winter capacity requirement based on the amount of winter ICAP in the reliability model (NYISO Proposal, p. 4: "The proposed Winter NYCA Minimum ICAP Requirement would be derived from the available capacity in the winter peak month, as identified from data for the final IRM study case and the winter NYCA forecasted peak load value for the applicable Capability Year as determined by the NYISO."). This appears to be well above the reliability need as reflected in the winter transmission security requirement. See NYISO, [2025 Q4 STAR Report](#), Figure 46, p. 75, showing the amount of winter supply exceeding the transmission security needs in Zone J (i.e., the winter peak transmission security margin in Row M of the table in Figure 46) by over 1,000 MW through 2032 (this appears to omit consideration of CHPE, consistent with the IRM model for winter; CHPE would further increase the winter transmission security margin).

1 alternative solutions I describe above maintain the integrity of NYSRC/NYISO's
2 reliability study processes by limiting the amount of capacity that can be offered or
3 reconfigured on a monthly basis to a level that avoids "large unit" concerns so it does not
4 materially impact results from the IRM, LCR, and TSL reliability studies. By capping
5 monthly variability from a supply source in Zone J in winter to approximately 700–800
6 MW (or another value supported by NYISO analysis), the minimum capacity value
7 needed for reliability as determined in reliability studies remains valid.⁵³ Indeed, this
8 large-unit cap proposed in the alternative solutions is defined to be the level at which the
9 reliability need (for meeting the resource adequacy or transmission security criteria, as
10 applicable) would not be materially affected by import offer variability from a UDR
11 holder.

12 The cap on the maximum quantity of variable monthly imports would be derived from
13 NYISO's reliability modeling. Specifically, it would be selected such that the presence or
14 absence of a single supply source up to the size of the cap does not have a material impact
15 on the amount of total capacity needed to meet reliability (i.e., yielding a stable demand
16 curve). As discussed in Section V above, that would not be the case for a large single-
17 source contingency due to the "large unit effect". This effect has different thresholds for
18 resource adequacy (which depends on probabilistic loss-of-load metrics) and for
19 transmission security (which is driven by deterministic contingency analysis, often
20 focused on the largest contingencies). Because CHPE sells capacity in Zone J, and
21 because Zone J is constrained by transmission security needs for the foreseeable future, I
22 focus here on transmission security.

23 Transmission security requirements are incorporated into the capacity market to help
24 NYISO meet its transmission planning requirements via generator investment and
25 retention, in particular for the N-1-1 study cases in load pockets such as Zone J.⁵⁴ The
26 amount of supply needed to meet the transmission planning requirements is primarily a

⁵³ This provision would ensure alignment for a winter capacity requirement based on winter reliability needs. As noted in footnote 52 above, the NYISO's proposed winter demand curve is not based on winter reliability needs.

⁵⁴ NYISO plans for a somewhat stricter N-1-1-0 security in Zone J. For the present discussion, I consider that a type of N-1-1 study.

1 function of the peak load in the area and of the transmission import capability, which (to a
2 first-order approximation) is not a function of the availability of individual supply
3 sources. However, two second-order factors can come into play. First, and most
4 importantly, because the relevant case is an N-1-1 case for which the loss of the two
5 largest contingencies poses the constraining factor, any time a supply source becomes one
6 of the two largest contingencies it will effectively be absent from the planning case
7 (although it will have also displaced a prior large contingency which becomes available in
8 the case). This is the “loss of source contingency” effect. Any supply source below the
9 size of the second contingency avoids this effect. As noted in footnote 39 above, this
10 second contingency size is approximately 785 MW in Zone J. Sources larger than the
11 second contingency will increase the TSL Floor because of this effect.⁵⁵ Second, a
12 generator at a given location may shift power flows on transmission lines that define the
13 constrained zonal interface with the rest of NYISO. This could potentially slightly
14 increase or decrease the maximum power that can flow across the interface. This effect is
15 likely small compared to the loss of source contingency effect.⁵⁶

16 It is also important to recognize that reliability risk is growing in shoulder months,
17 making it increasingly valuable to have access to as much supply in these months as
18 possible (such as is facilitated by the two solutions). For example, MISO is beginning to
19 see reliability risk in November,⁵⁷ PJM anticipates problems scheduling shoulder-month

⁵⁵ NYISO, [Champlain Hudson Power Express \(CHPE\): Installed Capacity Market Integration Considerations](#), presentation to the Installed Capacity Subcommittee, July 10, 2025, p.7. (NYISO discusses the impact of summer capacity supply from CHPE: “This preliminary assessment has identified a potential increase of approximately 4% to the previously calculated 2025–2026 TSL floor value for Load Zone J...The potential impact to the Load Zone J TSL floor value is due to the expectation that the inclusion of CHPE UDRs will change the loss of source contingency analyzed in determining transfer capability into Load Zone J resulting in a decrease in the bulk transfer limits into Load Zone J” (emphasis added).)

⁵⁶ Note that, with respect to summer capacity supply from CHPE in footnote 55, NYISO attributes the change in TSL Floor entirely to the first factor (the loss of source contingency effect). Separately I observe that, while the second factor would tend to be more impactful for larger units, it can occur for any size or type of resource, including those not subject to a 15-month ahead commitment with must-offer obligation.

⁵⁷ North American Electric Reliability Corporation, [2024 Long-Term Reliability Assessment](#), December 2024, corrected July 11, 2025, p. 42 (“MISO has continued the seasonal capacity auction construct and has found growing evidence of risk in non-peak (e.g., spring and fall) seasons.”); MISO, [Planning Year 2025-2026 Loss of Load Expectation Study Report](#), p. 21 (“In Planning Year 2025-2026, September risk increased and November demonstrated some morning and evening risk hours.”).

1 outages,⁵⁸ and the North American Electric Reliability Corporation (NERC) recently
2 issued a report on “Load-Pocket Shoulder Season Challenges” identifying four shoulder-
3 season events that resulted in load shedding (several of which were in April).⁵⁹ This
4 change in risk is driven in part by deployment of variable energy resources and storage
5 resources that displace thermal generators in the resource mix, thus shifting conventional
6 temporal patterns of reliability risk to periods of low renewable availability (including
7 potentially during shoulder months). Shrinking installed reserve margins also cut into the
8 ability to schedule maintenance outages without triggering shortages. Therefore, the two
9 solutions would improve reliability by making as much supply available as possible on a
10 monthly basis, including in shoulder months.

11 In sum, a cap at the size of the second largest contingency for Zone J transmission
12 security (e.g., in the range of 700–800 MW) would likely avoid impacts to the capacity
13 that NYISO determines to be required to meet winter transmission security needs in Zone
14 J.⁶⁰ To ensure alignment of auction conditions with reliability studies while continuing to
15 allow for monthly capacity market participation by UDR and EDR holders, NYISO would
16 need to confirm the cap sizes using TSL methodologies (noting that only the TSL
17 methodology is likely to be relevant for the foreseeable future) or MARS (for localities in
18 which resource adequacy is the binding constraint, including for EDRs in the Rest-of-
19 State region).

20 Relative to the NYISO proposal, the proposed solutions for continued monthly
21 participation allow higher levels of capacity to be committed to NYISO in months for
22 which such capacity is physically available. This improves transmission security and
23 adequacy in such months because that capacity is obligated to be available to NYISO
24 operators and cannot be committed elsewhere.

⁵⁸ PJM, [Additional Large Load Challenges: Peak vs Shoulder Seasons and Gen Outage Scheduling](#), October 21, 2025, p. 4 (“As reserve margins shrink, generation outages will be more challenging to schedule while avoiding emergency procedures”).

⁵⁹ NERC, [Incident Review Load-Pocket Shoulder Season Challenges](#), March 4, 2026, pp. 3 – 6

⁶⁰ A different cap may be warranted to avoid resource adequacy impacts, which are not applicable in Zone J.

1 The proposed monthly solutions are therefore consistent with NYISO's use of the
2 capacity market to meet reliability needs.

3 **Q: HOW WOULD THE SOLUTIONS FOR CONTINUED MONTHLY CAPACITY**
4 **MARKET PARTICIPATION BY UDR/EDR HOLDERS BE IMPLEMENTED,**
5 **AND WHAT ADMINISTRATIVE STEPS WOULD THEY ADD?**

6 A: The first alternative retains all of the of the features of the NYISO proposal for must-offer
7 obligations on holders of UDRs and EDRs with MW elections that exceed the large-unit
8 cap, while otherwise retaining the status quo approach to monthly participation by
9 UDR/EDR holders. Thus, additional implementation steps relate only to administration
10 and application of the large-unit cap.

11 The second alternative allows offers up to the large-unit cap from a seller who has
12 returned UDRs for a season (subject to certain restrictions) and otherwise keeps NYISO's
13 proposed must-offer obligation for elected UDR/EDR MWs. This may require adjustment
14 to the UDR/EDR framework to allow for monthly sales above the UDR/EDR MW level,
15 or to "reclaim" UDR/EDRs for a month as needed. The approach would also require
16 administering the large unit cap. In addition, NYISO staff would need to verify feasibility
17 for capacity imports above the retained UDR/EDR levels (e.g., by confirming the imports
18 do not exceed CRIS rights).

19 The "large unit" size cap is a direct and administratively simple way to address NYISO's
20 alignment concerns with respect to reliability outcomes. By imposing a cap on the size of
21 variable monthly offers, the alternatives allow NYISO to maintain substantially the
22 existing schedule of pre-auction activities so there is no need to change the timeline of or
23 rerun the IRM, TSL, and LCR studies. Under both solutions, NYISO would continue to
24 receive information regarding intended monthly offers 15 months before the start of the
25 winter season. The information can support planning and stakeholder transparency.

26 The large-unit cap may need to be revisited on a periodic basis, especially in the unlikely
27 event that a different facility becomes one of the two largest contingencies in a season.
28 However, since CHPE will already be one of the top two contingencies for the summer
29 TSL (and its impact is therefore already incorporated into the summer reliability

1 requirement), and since the winter reliability requirement is not used in setting the winter
2 demand curve, I expect a revisited cap to yield substantially the same value for the
3 foreseeable future.

4 Therefore, the solutions to allow for continued monthly capacity market participation by
5 UDR/EDR holders will add minimal additional implementation complexity to NYISO's
6 proposal.

7 **Q: HOW WOULD THE TWO SOLUTIONS APPLY TO IMPORTS OVER THE HQ**
8 **DENNISON INTERTIE?**

9 A: HQ's Dennison Intertie ("Dennison") is a 279 MW controlled AC tie between HQ and
10 NYISO Zone D (in the NYCA capacity region). HQUS holds 80 MW of EDRs on
11 Dennison and uses them to offer up to 80 MW of summer and winter capacity.

12 The same principles by which CHPE could flexibly offer variable quantities up to a cap
13 into the monthly capacity auctions in Zone J also apply to Dennison in the NYCA region.
14 However, the circumstances around the size cap are different. The NYCA region does not
15 have a TSL Floor and so is constrained only by the resource adequacy reliability
16 requirement. Further, the NYCA region is large, comprising the entirety of NYISO, with a
17 baseline winter peak load of 25,850 MW forecasted for winter 2028–29.⁶¹ By comparison,
18 Dennison's 80 MW winter capacity eligibility is very small. There are over 100 units
19 larger than Dennison's EDRs, including the 2,860 MW Robert Moses Niagara Power
20 Plant and the 1,399 Nine Mile Point Unit 2. Therefore, the presence or absence of
21 Dennison's EDR capability in the resource adequacy model will not make a difference for
22 the reliability needs identified for NYCA in the model. That is, the size cap for NYCA
23 would be larger than 80 MW, and therefore there is no need to apply a must-offer
24 obligation on Dennison in order to achieve alignment in reliability needs between the
25 reliability model and the auction.

⁶¹ Gold Book, p. 17.

1 **Q: HOW WOULD THE TWO SOLUTIONS FIT WITHIN NYISO’S MARKET**
2 **POWER MITIGATION FRAMEWORK?**

3 A: The solutions allow a UDR holder to offer all (or nearly all) of its available capacity,
4 notwithstanding a monthly-varying profile in physical capability from the HQ system.
5 Except for any constraining effect due to the cap, this is consistent with the existing
6 market power mitigation construct (which requires the full available capability to be
7 offered). Therefore, the solutions are fully consistent with the existing market power
8 mitigation framework.

9 **Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

10 A: Yes, it does.

APPENDIX: CONSUMER COST IMPACT ANALYSIS

This appendix describes the methodology used to quantify the change in consumer costs from recognizing 300 MW of CHPE imports in NYISO’s winter capacity auctions for three shoulder months. We estimate the change in capacity auction clearing prices and volumes in Zone J (NYC), G–J, and NYCA by adding 300 MW of capacity from CHPE to each auction’s supply curve and clearing against the applicable winter demand curve under NYISO’s proposed Winter Reliability Capacity Enhancements. For each capacity region before and after the addition of 300 MW of imports, we estimate the total capacity market cost as clearing price times cleared quantity (minus the quantity cleared in auctions for any capacity regions nested within). We calculate the resulting savings to New York consumers by comparing the total capacity market settlement prior to the additional 300 MW with the total settlement after the addition.

Because NYISO’s proposed winter enhancements are intended to be implemented in 2027, we evaluate consumer cost impacts for the 2027/28 winter.

Key assumptions are as follows:

- **Capacity value:** CHPE contributes 300 MW UCAP in each of the three shoulder months in winter.
- **Demand curve:** NYISO incorporated the proposed winter enhancements into the 2025/26 winter ICAP demand-curve parameters.⁶² Using these enhanced parameters as the baseline, we construct 2027/28 winter UCAP demand curves by (i) updating the reference point and zero-crossing point using the winter non-coincident peak load forecast from NYISO’s 2025 Gold Book,⁶³ (ii) escalating the reference point price and maximum clearing price from 2025/26 to 2027/28 using the projected cost escalation of a 2-hour battery energy storage system, and (iii) translating the ICAP demand curve to a UCAP demand curve.

⁶² NYISO, [Winter Reliability Capacity Enhancements: Market Design Details and Review of Proposed Tariff Revisions](#), October 28, 2025, p. 17.

⁶³ NYISO Proposal, p. 5 (“The proposed Winter LCRs would be calculated based on the applicable Locality non-coincident peak load forecast as modeled in the final IRM study case.”); Gold Book, Table I-4b, p. 27.

- **Supply curve:** We assume a vertical supply curve, which is a simplifying assumption but relatively accurate in the case of NYISO's spot capacity markets. The price reduction would be moderated under a sloped supply curve, and the consumer savings lessened to a degree. CHPE's 300 MW is assumed to be offered at \$0.
- **Auction clearing point:** For 2027/28, the baseline auction is assumed to clear at the reference point plus level of excess. At this auction clearing point, the clearing price equals Net Cost of New Entry (CONE), and the cleared quantity equals the UCAP requirement plus the UCAP of a peaking unit. This reflects the design of NYISO's demand curve to provide revenue adequacy for the applicable peak plant at the level of excess conditions.

Table A-1 below summarizes the assumptions and calculations used to construct the 2027/28 winter UCAP demand curve in Zone J. The winter non-coincident peak load for 2027/28 winter for each locality is drawn from the load forecast in NYISO's 2025 Gold Book. The IRM/LCR is from the winter IRM/LCR reflected in the existing 2025/26 Capability Year minimum ICAP requirements (which we understand to be based on the aggregated ICAP of resources in the reliability model in winter).⁶⁴ The winter ICAP requirement is calculated by multiplying winter peak load by the LCR.

NYISO published the proposed winter reliability capacity enhancements as applied to 2025/26 winter ICAP Demand Curve Parameters including the winter zero crossing point, winter level of excess, winter max clearing price, and winter reference price.⁶⁵ We escalate the winter max clearing price and winter reference price from 2025/26 to 2027/28 using an escalation rate index of 0.92%. The escalation rate index is derived based on the cost component-weighted growth rate for a 2-hour Battery Energy Storage System

⁶⁴ NYISO, [Winter Reliability Capacity Enhancements: Market Design Details and Review of Proposed Tariff Revisions](#), October 28, 2025, p. 15.

⁶⁵ *Id.*, p. 17.

(BESS) used in NYISO's 2025–2029 ICAP Demand Curve Reset.⁶⁶ By way of this step, all parameters are available for 2027/28 winter ICAP demand curve.

We then convert 2027/28 winter ICAP demand curve to winter UCAP demand curve using the applicable factors listed in Table A-1, most notably the ICAP-UCAP translation factor published by NYISO. The UCAP max clearing price is calculated as $\text{ICAP max clearing price} / (\text{CAF} \times (1 - \text{Derating Factor}))$ and similarly, the UCAP reference price is calculated by $\text{ICAP reference price} / (\text{CAF} \times (1 - \text{Derating Factor}))$, using the CAF and Derating Factor for the reference peaking unit.⁶⁷

The winter UCAP requirement is calculated by applying the most recent ICAP/UCAP requirement translation factor used in the 2025/26 winter capability period: $\text{Winter ICAP requirement} \times (1 - \text{translation factor})$.⁶⁸ The UCAP zero-crossing point is calculated as the winter UCAP requirement multiplied by the zero-crossing percentage.

Finally, we establish the clearing point for the baseline auction without CHPE. We set supply such that cleared quantity equals the winter UCAP requirement plus the UCAP level of excess, where the level of excess reflects the size of the peaking unit (i.e., a 2-hour BESS). I calculate the UCAP level of excess as the ICAP of the peaking unit (200 MW) multiplied by the CAF of a 2-hour BESS and $(1 - \text{Derating Factor})$.⁶⁹

⁶⁶ Analysis Group, ICAP Working Group, [NYISO 2025-2029 ICAP Demand Curve Reset \(DCR\), Annual Updating of ICAP Demand Curve Parameters](#), August 22, 2024, p. 7.

⁶⁷ Zach T. Smith, [ICAP Demand Curve](#), November 5–6, 2025, pp. 38–39.

⁶⁸ NYISO, [ICAP/UCAP Translation of Demand Curve, Winter 2025–2026 Capability Period](#), p. 1.

⁶⁹ Mike Swider, [Winter Reliability Capacity Enhancements: Market Design Update and Review of Additional Proposed Tariff Revisions](#), October 14, 2025, p. 14; Zach T. Smith, [ICAP Demand Curve](#), November 5–6, 2025, p. 38.

**Table A-1. Assumptions and parameters in constructing
2027/28 winter UCAP demand curve in Zone J**

ICAP Demand Curve		
Peak Load (MW_ICAP)	[1]	7,700
LCR %	[2]	121%
Winter ICAP Requirement (MW_ICAP)	[3]	9,328
Winter Zero Crossing Point (%)	[4]	111%
Winter Level of Excess (MW_ICAP)	[5]	200
Winter Maximum Clearing Price (\$/kW_ICAP/month)	[6]	\$24.75
Winter Reference Price (\$/kW_ICAP/month)	[7]	\$10.41
ICAP -> UCAP Translation Factors		
Capacity Accreditation Factors (CAFs) of 2-hr BESS	[8]	64.94%
Derating Factor	[9]	2.50%
ICAP/UCAP Requirement Translation Factor	[10]	6.80%
UCAP Demand Curve		
Winter Maximum Clearing Price (\$/kW_UCAP/month)	[11]	\$39.09
Winter UCAP Requirement (MW_UCAP)	[12]	8,694
Winter Reference Price (\$/kW_UCAP/month)	[13]	\$16.44
Winter Zero Crossing Point (MW_UCAP)	[14]	9,650
Winter UCAP Level of Excess (MW_UCAP)	[15]	127
Net CONE (\$/kW_UCAP/month)	[16]	\$14.26

Sources and notes:

[1]: Gold Book, Table I-4b, p. 27.

[2]: NYISO, "[Winter Reliability Capacity Enhancements: Market Design Details and Review of Proposed Tariff Revisions](#)," October 28, 2025, p. 15.

[3]: [1]×[2]

[4]: NYISO, "[Winter Reliability Capacity Enhancements: Market Design Details and Review of Proposed Tariff Revisions](#)," October 28, 2025, p. 17.

[5]: NYISO, "[Winter Reliability Capacity Enhancements: Market Design Details and Review of Proposed Tariff Revisions](#)," October 28, 2025, p. 13.

[6]: Escalated from the 2025/26 maximum clearing price (by a rate of 0.92%) presented in NYISO, "[Winter Reliability Capacity Enhancements: Market Design Details and Review of Proposed Tariff Revisions](#)," October 28, 2025, p. 17.

[7]: *Id*, Escalated from the 2025/26 reference price (by a rate of 0.92%)

[8]: Pallavi Jain, "[2025 - 2026 Final Capacity Accreditation Factors and Peak Load Window](#)," 2025, p. 5.

[9]: Zach T. Smith, "[ICAP Demand Curve](#)," November 5–6, 2025, p. 38.

[10]: [ICAP/UCAP Translation of Demand Curve, Winter 2025-2026 Capability Period](#), p.1.

[11]: $[6]/([8] \times (1 - [9]))$

[12]: $[3] \times (1 - [10])$

[13]: $[7]/([8] \times (1 - [9]))$

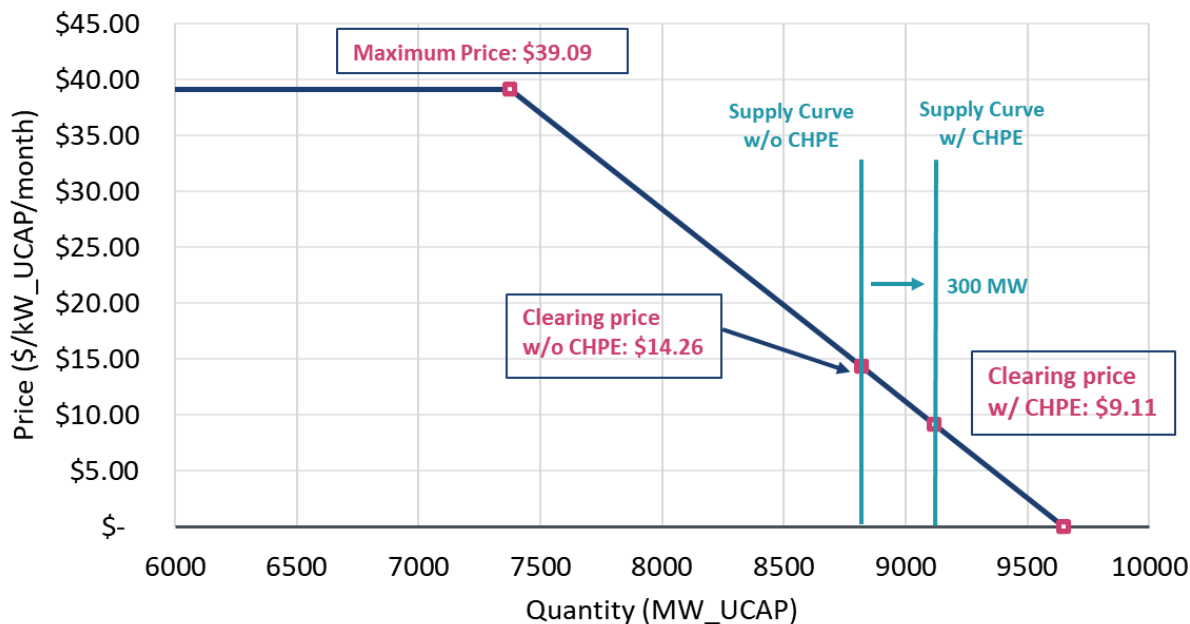
[14]: $[12] \times [4]$

[15]: $[5] \times [8] \times (1 - [9])$

[16]: Same as clearing price calculated using slope of UCAP demand curve at Level of Excess.

Figure A-1 illustrates the impact of CHPE's 300 MW of capacity on the auction outcome in Zone J. Adding 300 MW of capacity from CHPE shifts the Zone J supply curve to the right by 300 MW, increasing the cleared quantity from 8,821 MW UCAP to 9,121 MW UCAP and reducing the clearing price from \$14.26/kW-UCAP-month to \$9.11/kW-UCAP-month. As a result, I calculate that consumers would pay approximately \$128 million less in Zone J capacity payments over the three winter months in 2027/28, reflecting lower capacity prices despite a modest increase in the cleared quantity.

FIGURE A-1. IMPACT OF CHPE ON CAPACITY CLEARING IN 2027/28 WINTER AUCTION



Sources: the maximum price, zero crossing point, and the clearing point are based on the assumptions in Table A-1 above.

Given NYISO's nested capacity auction structure, the additional 300 MW of supply in Zone J also shifts the supply curves in the G–J and NYCA auctions, thereby affecting clearing prices in G–J (and thus the settlement cost to customers for the G–I results) and in NYCA (and thus the settlement cost to customers of the NYCA results). I apply the same methodology used for Zone J to the G–J and NYCA auctions. I find that the G–J clearing price decreases from \$4.74/kW-UCAP-month to \$3.41/kW-UCAP-month, reducing capacity costs by approximately \$14 million. Similarly, we estimate capacity cost savings of approximately \$23 million for Rest-of-State (Zones A–F) results. Table A-

22 Table A-2 summarizes the estimated capacity cost savings across New York
consumers.

TABLE A-2. ESTIMATED CONSUMER COST IMPACT OF 300 MW CHPE CAPACITY FOR 3 MONTHS IN 2027/28 WINTER AUCTION

Consumer Cost Impact of 300 MW CHPE Capacity for 3 months in 27/28 Winter Auction

	UCAP Requirement MW	Reference Price \$/kW _UCAP-mo	Zero Crossing Point MW	Cleared Quantity MW	Cleared Price \$/kW _UCAP-mo	Capacity Cost \$ million, over 3 months
<i>Without CHPE Capacity</i>						
NYCA	36,434	4.39	39,750	36,579	4.19	
G-J Locality	12,062	5.38	13,275	12,207	4.74	
K	5,002			5,105		
NYC	8,694	16.44	9,650	8,821	14.26	377
G-I				3,386	4.74	48
Rest-of-State (A-F)				19,267	4.19	242
<i>With CHPE Capacity</i>						
NYCA	36,434	4.39	39,750	36,879	3.80	
G-J Locality	12,062	5.38	13,275	12,507	3.41	
K	5,002			5,105		
NYC	8,694	16.44	9,650	9,121	9.11	249
G-I				3,386	3.41	35
Rest-of-State (A-F)				19,267	3.80	219
<i>Capacity cost savings</i>						
NYC						128
G-I						14
Rest-of-State (A-F)						23
Total Consumer Savings						165

Notes: UCAP Requirement, Reference Price, and the Zero-Crossing Point are based on the UCAP demand curve for each locality, as described in **Table A-1**. The cleared quantity is calculated as the UCAP Requirement plus the level of excess, plus 300 MW in the applicable case. The clearing price is determined from the demand-curve slope and the cleared quantity. Capacity cost in each locality is calculated by multiplying the clearing price by the cleared quantity applicable to consumers in that locality. The capacity cost savings are calculated as the difference between the capacity cost without and with CHPE.

* * *

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

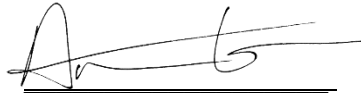
**New York Independent System Operator,)
Inc.**

Docket No. ER26-1431-000

DECLARATION OF ANDREW LEVITT

I, Andrew Levitt, identified in the foregoing prepared testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony and the exhibits attached thereto to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on March 11, 2026.

A handwritten signature in black ink, appearing to read 'A. Levitt', is written over a solid horizontal line.

Andrew Levitt