Capacity Resource Accreditation for New England's Clean Energy Transition

REPORT 1: FOUNDATIONS OF RESOURCE ACCREDITATION

PREPARED BY

Samuel A. Newell
Kathleen Spees
John Higham

PREPARED FOR

Massachusetts Attorney
General's Office

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Brattle

OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF MASSACHUSETTS

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Executive Summary

As the New England Power Pool (NEPOOL) and the Independent System Operator of New England (ISO-NE) embark on modernizing resource adequacy accreditation, the Massachusetts Attorney General's Office (AGO), Office of Ratepayer Advocacy has asked us for assistance. This paper, "Report 1," establishes a problem statement for that effort, provides a conceptual basis for approaching it, and proposes criteria for evaluating accreditation solutions. To inform the discussion, we also summarize case studies on how other jurisdictions are addressing similar problems. A subsequent "Report 2" will build on Report 1 and suggest possible guidelines for ISO-NE's priorities and approach.

New England, like other regions, currently relies on just-in-time gas-fired generation and will be increasingly relying on intermittent renewables, energy-limited storage, and a variety of demand-side resources. These changes are shifting the timing and nature of shortage risks and the value of various resources for mitigating those risks. New methods are needed to appropriately quantify resource adequacy needs and different resources' contributions, so as to signal adequate, cost-effective investment to ensure ongoing reliability and to enable the region's clean energy transition.

Other regions further along in the transition to clean energy or otherwise further along reforming resource adequacy and accreditation provide several existing approaches. The central concept for all of these approaches is to identify a methodology that accurately measures the reliability contributions of *all* capacity resources, such that 1 MW provides equivalent reliability value, or effective load carrying capability (ELCC), regardless of the underlying resource type. We review the California Independent System Operator's (CAISO's) and PJM's "ELCC" approaches for intermittent and energy-limited resources; Southwest Power Pool's (SPP's) proposed ELCC method; Alberta's once-proposed performance-based tight hours approach; Midcontinent Independent System Operator's (MISO's) discussions on performance-based accreditation for thermal resources and wind ELCC and the New York Independent System Operator's (NYISO's) early-stage discussions similar to ISO-NE's.

It is often the unique intermittent nature of wind and solar resources that triggers these discussions, although in New England the more immediate issue is winter risks during extended cold snaps, when gas-fired resources and oil-fired resources have limited ability to continue generation. At a minimum, enhanced modeling and data analysis are needed to support revised requirements and accreditations considering these risks. A recent study conducted by Astrapé Consulting found that conventional EFORd-based[1] capacity accreditation likely significantly overstates the reliability of thermal resources.[2] In order to ensure reliability and efficient investment, ISO-NE will have to improve its thermal resource accreditation. ISO-NE should also consider splitting its annual resource adequacy program into separate winter and summer components. Seasonal accreditation would allow ISO-NE to more precisely address the unique reliability challenges of each season.

In addition, although wind and solar currently serve less than 5% of New England's energy demand (compared to supplying >25% in California, SPP, and the Electric Reliability Council of Texas (ERCOT)), the region will need accurate modeling of these resources and appropriate resource adequacy accreditations of all types as they expand rapidly and increasingly displace thermal resources.

Our initial examination of ISO-NE's needs and industry-wide practices leads to several inter-related recommendations to assist in guiding ISO-NE and NEPOOL's resource adequacy and accreditation reform process. These are necessary to facilitate industry transformation while maintaining reliability at minimum costs to consumers:

- **Improve resource adequacy modeling** to capture the main shortage risks in the current and future systems in order to refine both the capacity requirements and accreditation. Currently, the most prominent risks are likely in extended cold snaps; future risks will arise from reliance on correlated intermittent resources and energy-limited resources.
- **Break the annual construct into seasons** to enable more precise targeting of unique seasonal risks. Even with improvements to winter resource adequacy modeling, a single annual approach is ill-suited to address both summer and winter reliability risks.
- **Enhance accreditation to reflect each resource's contribution to the reliability objective**. This requires a better modeling foundation as noted above, including empirical data on resources' weather drivers, and other resource information that may affect reliability value (such as access to firm fuel). The totality of the information derived from modeling, historical performance data, and resource characteristics must be considered to develop a robust accounting system that fully measures the reliability concerns affecting each technology.

[1] Equivalent Forced Outage Rate Demand (EFORd) is a metric that expresses the probability that a given resource is unavailable due to forced outage at any given time.

[2] Astrapé Consulting, "Accrediting Resource Adequacy Value to Thermal Generation," March, 2022, p. 6.

- **Thoroughly examine all resource accreditation options.** Developing and evaluating the best combination of approaches will require an extensive analytical exercise, back-testing accuracy to the extent possible, and thinking creatively about how to address the limitations of each approach.
- In pursuing accreditation approaches and all the technical details, it is essential that **all resources are treated equitably** to provide an accurate exchange rate of value for resource investors to consider. This equitable treatment requires that the accreditation concept (though not necessarily the specific approach) should be applied to all resource types, including thermal resources, and that individual resources should have the incentive and opportunity to innovate and improve performance beyond the class-average estimated accreditation.

As NEPOOL, ISO-NE, the New England States, and stakeholders assess the various options for resource accreditation in New England, we suggest the assessment criteria for each option should include: reliability, economic efficiency, technology neutrality, resource-specific incentives to improve performance, implementation practicality, transparency, and consumer cost. We discuss these criteria more fully in the conclusion of this report and will apply them in our forthcoming report assessing the various design options.

I. Background on Resource Adequacy and Capacity Accreditation

A. Resource Adequacy in New England

RESOURCE ADEQUACY AND ACCREDITATION CONCEPTS

Most electrical systems have a "resource adequacy" standard to ensure that enough resources will be available in aggregate to almost always meet demand, even during extreme peaks in demand or supply disruptions. In New England, the standard is defined by the Northeast Power Coordinating Council (NPCC) as having sufficient resources such that demand can be met in all but one event in ten years. This standard has been in place for decades and is similar to that in most of North America (despite not having been studied for economic optimality).[3]

To meet that standard, ISO-NE, like most other system operators, determines a corresponding reserve margin requirement using probabilistic modeling. ISO-NE uses the GE Multi-Area Reliability Simulation (MARS) model to simulate hourly load and resource availabilities. Load patterns reflect a year 2002 hourly load shape but with load levels subjected to random perturbations to higher/lower levels representing a distribution of weather-driven possibilities.[4] Resources reflect the current fleet, subjected to random forced unit outages corresponding to historical outage rates. ISO-NE also incorporates several more details related to imports, zonal transmission constraints, and other factors.

The ISO-NE resource adequacy study is conducted iteratively each year, first observing the simulated frequency of shortages with the current fleet, then adjusting generic supply or demand until the one-in-ten target is met. The resulting fleet is then described as the sum of all modeled resources' capacity ratings (in MW)—and those capacity ratings must be consistent with the way resources in the actual fleet will be accredited as supply, or else meeting the required reserve margin would become meaningless. Then dividing the sum of modeled resources' capacity ratings by the forecast weather-normal peak load (minus 1) yields the required reserve margin,

[3] See Pfeifenberger, Spees, Cardin, and Wintermantel, *Resource Adequacy Requirements: Reliability and Economic Implication*, September 2013, report prepared for the Federal Energy Regulatory Commission.

[4] See ISO New England, *Installed Capacity Requirement (ICR) Reference Guide*, Rev. 2.0, September 15, 2021.

expressed as a percentage of peak load. Assuming all shortage risks have been realistically captured in the modeling, meeting the required reserve margin should satisfy the one-in-ten resource adequacy standard.

As we will discuss further below, risks to reliability are not in fact fully modeled, particularly with a transforming fleet. Risks not fully captured in ISO-NE's current model include winter and other extreme-weather correlated risks; variable, correlated wind/solar/load patterns corresponding to varying weather conditions; and perhaps also realistic operation of storage and demand response (DR) and uncoordinated maintenance scheduling. These shortcomings may lead the resource adequacy model to understate the reserve margins and resource types needed to meet reliability objectives.

Rather than resource accreditation, it is accurate modeling of shortage risks that is the most fundamental challenge for ensuring adequate supply. If the resource adequacy simulations accurately represent the risks and the adequacy of the simulated fleet, any errors in resource capacity accreditation would be partly self-correcting, at least in the short-term. For example, overstated accreditations for a certain type of resource would inflate not only the credit that suppliers of such resources receive, but also the nominal reserve margin requirement itself (since that is derived by aggregating the accreditations of the simulated fleet), thus absorbing the overstatement. The net error would be zero if the simulated fleet matched the actual fleet; or could be nonzero to the extent that resource substitutions occur among resources with different accreditation errors between the studies and the delivery year.[5] This too is a concern and warrants careful examination of accreditation alongside the modeling and setting of the standard itself.

Accurate accreditation is most important for signaling adequate and cost-effective investment in the resources that will compose the future fleet. That is, investors anticipating accurate accreditation can invest in such a way that will be resource-adequate overall. Anticipating accurate, resource-neutral capacity accreditations, and how accreditations may change over time—along with evolving, resource-neutral crediting for energy, ancillary services, and clean energy objectives—will also signal the most efficient fleet overall. Accurate accreditation can thereby support good decisions; for example, whether to install battery storage along with solar plants. To do so, accreditation must reflect resources' contributions to the resource adequacy objective as equivalent substitutable units.

[5] For example, if 2,000 MW of 20%-over-accredited resources replace 2,000 MW of correctly accredited resources, real capacity shortfalls would be 400 MW, or about 1% of the total requirement. Susceptibility to that error is limited by ISO-NE's updating the study annually, before each Annual Reconfiguration Auction.

IMPLEMENTATION THROUGH THE FORWARD CAPACITY MARKET

ISO-NE procures capacity supply through a forward capacity market (FCM). The sequence of steps is as follows:

1. **Qualification/Accreditation:** ISO-NE qualifies each resource to offer into the FCM for up to an accredited number of MW, based on its characteristics.

2. **Demand Determination:** ISO-NE conducts a probabilistic study (as described above) to determine the necessary reserve margin; then updates the load forecast to produce an Installed Capacity Requirement (ICR),[6] Net ICR, Local Sourcing Requirements (LSRs), and Maximum Capacity Limits (MCLs) for export-constrained zones. ISO-NE then uses those metrics to construct demand curves known as "Marginal Reliability Impact" curves.

3. **Forward Capacity Auctions (FCAs):** ISO-NE administers its Forward Capacity Auction (FCA) approximately three years before each delivery year. The FCA optimizes the selection of offers (expressed in $/MW-month) against the Marginal Reliability Impact curves to maximize social surplus. Cleared resources take on a capacity supply obligation (CSO) for the capacity commitment period (CCP) and will be paid in that period.

4. **Annual Reconfiguration Auctions (ARAs):** Each subsequent year approaching the delivery year, ISO-NE administers reconfiguration auctions, where suppliers can buy out of their obligations and have them assumed by other suppliers; ISO-NE can also buy or sell capacity to the extent the load forecast changes.[7]

5. **Certification:** Just before each delivery year, committed resources are certified for their readiness to provide capacity.

6. **Capacity Commitment Period (CCP):** Resources with a CSO must offer into the energy and ancillary services markets and must be available during shortages, subject to performance penalties and incentives under ISO-NE's Pay-for-Performance system. Incentives and Penalties are paid at a volumetric ($/MWh) rate[8] for providing energy or ancillary services

[6] See ISO New England, System Planning, Installed Capacity Requirement, accessed April 13, 2022. and ISO New England, *Installed Capacity Requirement (ICR) Reference Guide*, Rev. 2.0, September 15, 2021.

[7] See ISO New England, System Planning, Installed Capacity Requirement, accessed April 13, 2022.

[8] The Capacity Performance Payment Rate is currently set at $3,500/MWh. However, for the 2024–25 Capacity Commitment Period, it will increase to $5,455/MWh, and then for all subsequent Capacity Commitment Periods, it will be set at $9,337/MWh.

See Market Rule 1, Section III.13.7.2.

during shortage events, levied as a penalty for those performing below their obligation or a bonus for those paying above. The obligation is set at the CSO times a balancing ratio, calculated by the ratio of actual load + operating reserve divided by total CSOs outstanding. Thus, resources taking on lower CSOs will be less exposed to penalties and more exposed to upside, although they will have the same performance incentive per MWh either way as long as the performance incentives are fully funded.[9]

B. Resource Adequacy Challenges in the Clean Energy Transition

Electricity systems are transforming in New England and throughout the U.S., along several dimensions. Supplies are changing from traditional dispatchable generation with onsite fuel, to natural gas-fired generation relying on just-in-time (mostly non-firm) fuel delivery and to clean energy from intermittent wind and solar resources, as well as battery storage. On the demand side, inelastic consumers are slowly becoming more flexible with distributed energy resources (including distributed storage); electrification of vehicles and heating will increase load and alter load shapes.[10] Meanwhile, a changing climate will bring more severe and more frequent extreme weather events.

In New England specifically, reliance on gas-fired generation has increased dramatically over the last 25 years, while non-gas-fired generation capacity has retired (7,000 MW retired or announced retirement since 2013).[11] Solar and wind generation currently provides less than 5% of energy (compared to closer to 30% in some parts of the U.S.),[12] but will increase markedly over the next eight years to meet state Renewable Portfolio Standards (RPSs), and beyond that to meet state requirements to reduce economy-wide CO_2 emissions by 80% or more by 2050.[13]

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[9] The design of the capacity performance scheme is intended to create one MWh of penalties for every one MWh of surplus performance, such that under-performers would pay over-performance to compensate in a zero-sum system.

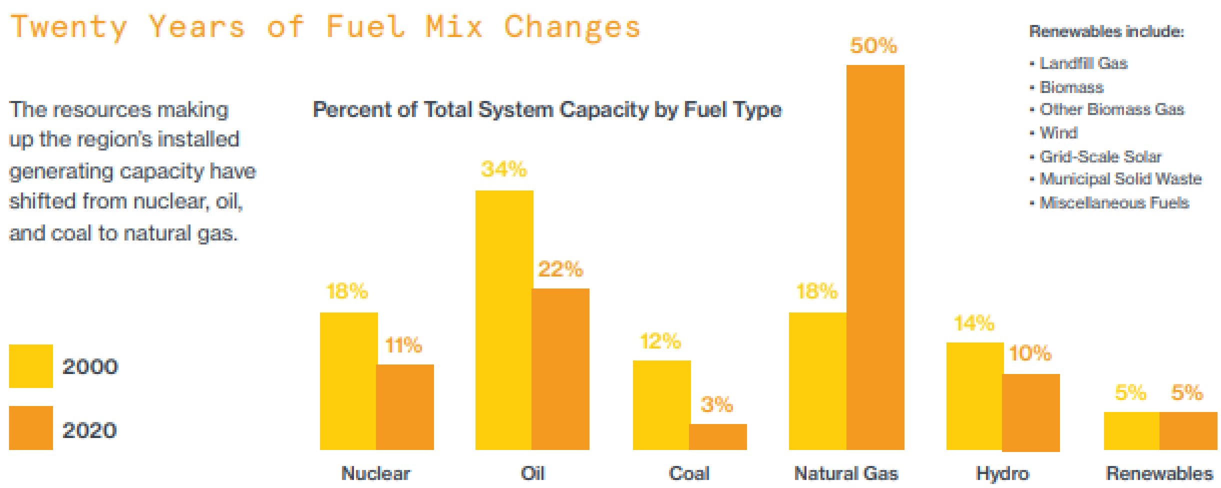
[10] Adoption of Vehicle-to-Grid capabilities or vehicle-based home back-up power will further impact load shapes in unique ways.

[11] ISO New England, *ISO New England's 2021/2022 Winter Outlook*, December 2021.

[12] SPP generation is over 33% wind (See Southwest Power Pool, Fast Facts, accessed April 29, 2022); CA supply is 24% solar + wind (See California Energy Commission, 2020 Total System Electric Generation Contact, accessed April 29, 2022); ERCOT supply is close to 25% wind and solar.

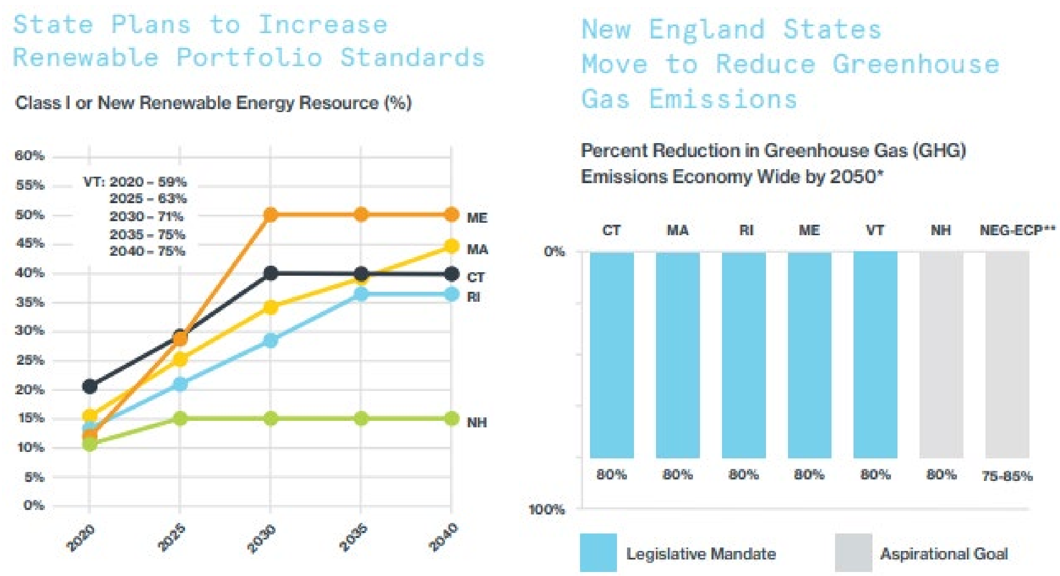
[13] ISO New England, *2021 Regional Electricity Outlook (REO): The Power of Change*, March 2021.

FIGURE 1. ISO-NE FUEL MIX COMPOSITION IN 2000 AND 2020



Source: *2020 CELT (Capacity, Energy, Loads and Transmission Report*, Summer Seasonal Claimed Capability (SCC) Capacity.

FIGURE 2. NEW ENGLAND STATES' RPS AND GHG REDUCTION TARGETS[14]



Source: ISO New England, 2021 Regional Electricity Outlook (REO): The Power of Change, March 2021, p 14.

These trends will challenge resource adequacy, shifting the nature and timing of shortage risks, and the ability of various resources to mitigate those risks. Most immediately, shortage risks may now be greater in the winter than the summer. In extreme cold snaps when gas local distribution company (LDC) demand spikes, electric generators that failed to contract for firm gas may be unable to obtain gas. In the event of fuel supply interruptions, generators that failed to procure back-up fuel supply may become unavailable, while those with limited back-up fuel supply may not have sufficient fuel stored or re-filled to serve through a long cold snap.

[14] *N.B.,* NEG-ECP is the Conference of New England Governors and Eastern Canadian Premiers.

While ISO-NE's leadership repeatedly warns the public about these risks and has looked to the states to address them,[15] ISO-NE has not yet offered modifications to its own requirements or resource accreditation or other market mechanisms that would incent the market to solve it. For example, ISO-NE has not proposed to modify its resource adequacy requirements and capacity market to include a winter demand for firm resources that can operate even when non-firm pipeline gas becomes unavailable. (ISO-NE has had measures outside of its resource adequacy construct to support winter reliability, including the defunct Winter Reliability Program.)[16]

To our knowledge, ISO-NE has not enhanced its probabilistic modeling to represent shortage risks under extreme cold conditions with correlated unavailability of non-firm, gas-fired resources. ISO-NE has also not reduced the accreditation of such resources for their inability to mitigate such risks, nor increased (or otherwise adjusted) the accreditation of other resources for their availability during such periods. These kinds of adjustments to modeling, requirements, and accreditation adjustments are presumably within the scope of ISO-NE's nascent work on accreditation. Implementing such adjustments will require incorporating extreme weather scenarios into the model, along with characterizations of how various resources perform under such conditions. That may require information on their fuel supply and storage arrangements and analyses of how different arrangements affect availability (for example, the effects of non-firm gas only vs. firm pipeline arrangements vs. back-up fuel of various durations). Observed history of availability in such conditions can provide insights into each resource's ability to perform.

ISO-NE should also consider splitting its annual resource adequacy program into separate summer and winter components. While ISO-NE expects to eventually transition from a summer-peaking to a winter-peaking system, in the more immediate future, ISO-NE will see shortage risk shift from the summer peak to the winter peak even while the summer peak continues to exceed the winter peak.

Longer term, as the region relies increasingly on solar and wind resources (displacing other capacity), risks will increase in the periods with low wind/solar output and relatively high load, that is, in the highest so-called "net load" hours.[17] For example, with increased solar generation during the afternoons, the shortage risk will shift to the evening as the sun goes down. Large

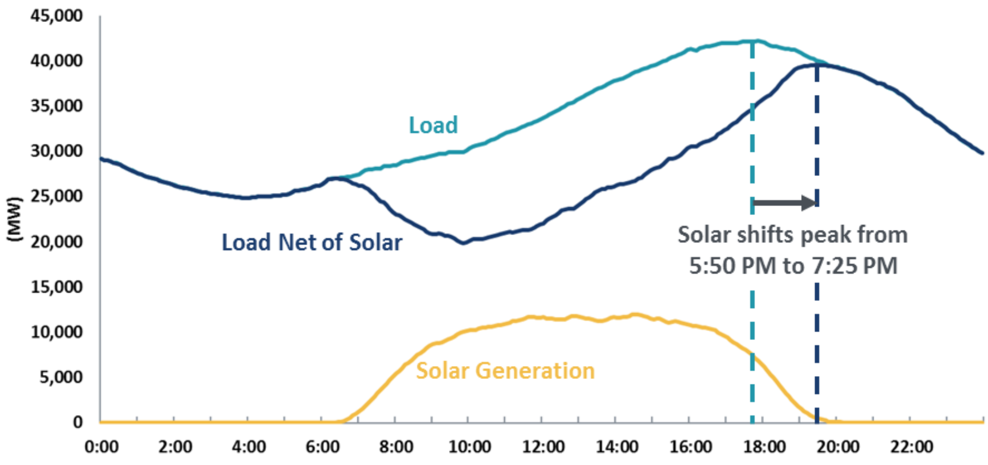
[15] See Memorandum from Gordon van Welie (President and Chief Executive Officer of ISO New England) to NEPOOL Participants Committee, January 31, 2022.

[16] ISO-NE, "Winter Program Payment Rate," accessed April 15, 2022.

[17] Net load refers to load net of intermittent renewable resources and represents the load that must be served by available dispatchable resources.

amounts of solar more than satisfy the afternoon load peak and move the net peak load into the evening when solar is less available, as illustrated in the figure below.

FIGURE 3. EXAMPLE: CAISO NET LOAD SHIFT AUGUST 12, 2021



Source: Brattle analysis of CAISO data.

Weather-driven intermittent performance suggests a need to consider wind/solar variability over a broad range of conditions, likely over many years, depending on how many years are needed for a representative sample, while considering that weather patterns are changing with climate change, and older patterns may be less representative.

ISO-NE's current resource adequacy modeling does not capture wind/solar variability over even the single 2002 load shape year. Intermittent resources are modeled at a constant output level given by their historical median output during defined hours.[18] Clearly, ISO-NE will have to enhance its modeling, resource adequacy requirements, and accreditation, as it has acknowledged by embarking on its exploration of new capacity accreditation options.

Other areas that may require enhancements include extreme correlated risks, sub-optimal maintenance scheduling, storage operation, and wind/solar/load corresponding to many weather patterns.

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[18] ISO New England, *Installed Capacity Requirement (ICR) Reference Guide*, Rev. 2.0, September 15, 2021.

II. Survey of Resource Accreditation Approaches and Key Studies

When capacity markets were first implemented, they started with rough measurements of resources' capacity value, but these accounting measurements have become more complex and more accurate over time. As resource mixes continue to transition from large, centralized, and firm-fuel (*i.e.,* coal and nuclear) generation towards natural gas-fired, intermittent, and distributed energy resources (DERs), capacity accounting conventions will need to continue to evolve. In a recent study, the North American Electric Reliability Corporation (NERC) identified the following emerging issues that may threaten reliability and require system operators to adapt and refine their approaches to resource adequacy:[19]

- Single-fuel dependency,
- Fuel security,
- DERs,
- Intermittent resource integration,
- Essential reliability services,
- Nuclear uncertainty, outages, and curtailments, and
- Transmission aging and outages.

In a 2013 report for the Federal Energy Regulatory Commission (FERC), study authors from The Brattle Group and Astrapé Consulting found prevailing accounting methods for capacity contributions of intermittent resources to be less precise than a more advanced ELCC-based approach.[20] The authors therefore elected to employ an ELCC-based accounting approach for both intermittent and DR resources.

According to a recent study conducted by Astrapé Consulting, conventional accreditation approaches for thermal resources may need to be revisited as well.[21] Study authors found that EFORd-based capacity accreditation likely significantly overstates the reliability of thermal

[19] NERC, "Probabilistic Adequacy and Measures," July, 2018, p. 11.

[20] Pfeifenberger, Spees, Cardin, and Wintermantel, *Resource Adequacy Requirements: Reliability and Economic Implication*, September 2013, report prepared for the Federal Energy Regulatory Commission, p. 63.

[21] Astrapé Consulting, "Accrediting Resource Adequacy Value to Thermal Generation," March, 2022, p. 6.

resources. Specifically, EFORd-based accreditation fails to account for outage variability, correlated outages, weather-dependent outages, and fuel supply outages.

In ISO-NE, the market is operated using an installed capacity (ICAP) accounting convention, in which traditional thermal generators and energy storage resources have capacity accreditation based on maximum output during peak demand conditions.[22] Under the ICAP accounting convention, generators' outage rates and fuel supply limitations are not considered in accreditation, leading to an even greater overstatement of thermal resource reliability value than an EFORd-based approach. Intermittent resources, however, are accredited according to their median performance during pre-defined reliability hours (hours ending 18–19 in winter and 14–18 in summer, plus any system-wide scarcity condition hours), averaged across the previous five years.[23] For all resource types, capacity ratings are calculated in both the summer and winter seasons, with the lower of the two values awarded as the resource's capacity value.[24]

Other capacity markets have already implemented or are in the process of implementing more accurate approaches to resource accounting. PJM, New York, and MISO have adopted an unforced capacity (UCAP) accounting convention for thermal, battery, and demand resources, in which resources' outage rates are applied so as to reflect a more accurate expectation of resource availability based on recent historical performance. For intermittent resources, other markets have traditionally used similar measures of resource output or class-average output during pre-defined windows to assess intermittent resource availability. However, many jurisdictions are increasingly transitioning toward the use of ELCC measures to assess capacity value such that all resources' capacity ratings will have uniform reliability value regardless of the underlying resource type. Detailed overviews of other jurisdictions' accreditation approaches are provided in Section IV.

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[22] ISO-NE, Market Rule 1, Section III.13.1.2.2.1.1.

ISO-NE, "Forward Capacity Market (FCM) Qualification Examples for Storage Technologies: Examples for Participation," March 2018.

[23] ISO-NE, Market Rule 1, Section 13.1.2.2.2.

[24] Resource owners can also engage in bilateral agreements to pair complementary summer and winter resources, so as to submit a higher aggregate annual capacity rating.

III. Considerations in ELCC-Based Resource Accreditation and other Similar Approaches

The three most promising options for accurately assessing resource adequacy contributions in modern electric systems are: (1) the "average" ELCC approach that measures the total reliability value of all resources of a single type; (2) the "marginal" ELCC[25] approach that measures the reliability value of the next resource added to the system; and (3) an empirical approach based on historical resource-specific availability/performance in specific high-risk hours. While the underlying goal of these options is identical, they all can produce substantially different results for individual resources and resource classes, which highlights the importance of supporting the chosen methodology with a robust program of analysis, analytical support, and technology-neutral assessment criteria. Importantly, it is possible and likely advantageous to pursue a hybrid approach that combines elements from multiple methods.

A. Reliability Modeling Platform and Approach

Probabilistic simulation models are central to determining reserve margins needed to meet resource adequacy objectives, such as NPCC's "one-in-ten" target, as discussed in Section I. Models can inform accreditation as well. Some of the most important issues for accurately characterizing risks and how different resources can mitigate them include:

- Modeling platform and its capabilities and limitations;
- How to capture a broad distribution of weather-driven load/sun/wind and their correlations;
- Modeling of resource outages and correlations, including in extended extreme weather;
- Treatment of transmission constraints, curtailments, and non-firm transmission rights; and
- Modeling of energy-limited storage and hybrids, DR, hydro and imports.

[25] Marginal Reliability Improvement (MRI) may be considered a sub-set of marginal ELCC and can be expected to yield very similar results. It relies on the same conceptual framework as marginal ELCC but employs a methodology that requires far fewer model runs. Since we consider these two options to be functionally synonymous, we only use the term "marginal ELCC" in this report.

Below we discuss each of these factors to help structure questions to raise with ISO-NE and to identify some of the limitations of available data modeling approaches to fully specify and help protect against all risks.

MODELING PLATFORM

Not all models are the same and none is perfect (though some are better than others). ISO-NE has been using the GE-MARS model, as has NYISO, although not necessarily leveraging the same features. PJM uses a combination of GE-MARS and its in-house PRISM model. CAISO, SPP, ERCOT, and many utilities use Astrapé's SERVM model. We understand ISO-NE has now engaged Astrapé to conduct analyses to inform its accreditation reforms. A few other models are established or in development but are not as widely used.

These models vary in their capabilities. SERVM has advanced features to model many weather years and consider fuel limitations and other correlated outages as described under the various topic areas below. In our view, SERVM or other advanced models should be used both for determining the resource adequacy objective and for accreditation, in combination with empirical data.

These models are probabilistic, simulating many scenarios drawn from distributions of possible conditions, and developing expected values of reliability outcomes across all scenarios. Simpler deterministic models or criteria can also be used to protect against certain scenarios, as in ISO-NE's Transmission Security Analysis that aims for each area to have enough supply to meet 90/10 peak load even when the largest generation or transmission outage occurs.

DISTRIBUTIONS OF WEATHER-DRIVEN LOAD/SUN/WIND AND CORRELATIONS

In preparing an electric system to have enough supply, it is most important to consider extreme weather conditions that can drive load up and resource availability down. Traditional modeling focused on summer peak load and how it could vary in extreme heat. ISO-NE, for example, simulates a single year (2002) hourly load shape but considers a range of conditions by fluctuating the load according to broader distributions derived from observations across a larger number of years.

However, current and emerging risks are shifting to other periods, including winter cold snaps and other periods when the wind or sun may not shine, as discussed in Section II. Hence it is becoming increasingly important to consider more dimensions of the weather and its simultaneous implications for load, wind/sun output, fuel availability, and outage rates. This can most straightforwardly be accomplished by simulating many years of weather data.

The analyst has to choose how many weather years to model, and other system operators have opted for as much as 30 years (in CAISO). Choosing more years provides a broader distribution of weather possibilities, and it is an empirical question how many are needed to capture enough of the long-term distribution. But more distant years may be less representative of a climate-changing future, where the frequency and magnitude of extremes may increase. There is no perfect answer for this, but it is worth considering weighing recent years with greater extremes more heavily and perhaps adding various conservative assumptions to requirements, in the reserve margin itself or in the peak load forecast to which the reserve margin is applied.

The other challenge is projecting the anticipated electric system's load and resource availability under past weather patterns.

- *Hourly load* could be simulated by incorporating historical weather data into a *short-term* bottom-up load forecasting model that accounts for the current system's mix of electricity uses, although this may not be directly possible if the short-term model is a neural network model that relies on ongoing observations of actual load and weather forecasts.
- *Hourly generation of wind and solar* resources cannot be observed in years/locations without such resources, so must be estimated as "putative" generation based on meteorological conditions. We understand that PJM uses advanced data services to do so for every kind of generator in every location, given its characteristics. This is cumbersome and data-intensive but possible.
- Hourly availability of dispatchable resources depends on outages and operations, discussed below.

RESOURCE OUTAGE MODELING

Some outages occur for idiosyncratic reasons and can be modeled as independent random events for each resource. Outages are more consequential, however, when driven by extreme temperatures or other common environmental forces affecting many resources simultaneously, and these correlated outages are more difficult and less common to model well, if at all. Correlated outages can be modeled in several ways: one is to measure historical outage rates and correlations by season or as a function of modeled weather. Outage rates and correlations might be informed by historical data, such as each resource's performance during the 2014 Polar Vortex. However, data from the past may be unrepresentative of resources' current condition and management practices for making the plant and fuel available. An alternative approach is to explicitly model causation of outages based on weather, system conditions, and unit-specified characteristics. For example, temperature can be translated into availability of non-firm natural gas, then fuel supplies including storage capacity can be translated into performance over the course of a multi-day cold snap.

Planned maintenance scheduling might also be considered in simpler or more advanced ways. Traditional systems were so summer-peaking (and sub-peaking in the winter) that maintenance could be scheduled in other times of the year without threatening reliability, and the models either ignored it or optimized the schedules across the year. Yet with risks shifting to other periods and with climate change increasing the likelihood of extreme conditions in a broader portion of the year, scheduled maintenance may become more likely to coincide with shortages. The question is how to model maintenance with a realistic amount of coordination across the fleet, or lack thereof.

AVAILABILITY OF ENERGY-LIMITED AND OTHER RESORUCES

Several classes of resources, such as battery storage and hydroelectric generation, have limitations that affect their availability during shortages in different ways that need to be considered in the models:

- *Energy-limited storage resources* may be available for short-duration events, but not fully for longer-duration events. This can be modeled within the resource adequacy model (including within GE-MARS) by optimizing the charge state of storage resources of various durations. There are at least two complications, however: one is that doing so fails to account for operators' imperfect information in managing their charge state in the real world; for example, a battery storage resource operator could discharge too early to capture high energy prices without anticipating a greater supplier shortage later in the day. A second complication is the interaction with other resources, such as DR (*i.e.*, it may be more economic for DR to curtail load "first" over an entire 6-hour event while saving 2-hour storage for the 2 super-peak hours, but that may not be realistic if the DR can only be called during emergencies).
- *Hybrid resources with intermittent generation, storage, and constraints*. Ideally, hybrid resources would have the same value as the sum of the intermittent generation and storage value. The value may be lower, however, in cases where the combined output is limited by a constraint at a shared inverter (in DC-coupled hybrids) or transmission equipment. Such a resource would have to be modeled with the constraint.
- *Demand response*. DR resources may have limitations on the number of calls per year and the number of hours per call, which must be accounted for in the simulations.

- *Imports*. Firm imports can be modeled deterministically, as ISO-NE does for contracted capacity from Hydro-Québec (HQ) and NY. But non-firm imports from neighbors are uncertain and should be reexamined by observing imports in recent shortage events, and by modeling all regions with super-regional weather patterns.

TRANSMISSION LIMITATIONS

Resource adequacy models such as GE-MARS represent limited transmission between defined zones. They do not represent all of the transmission facilities and how they might limit individual resources' ability to help meet loads. Typically, it is assumed that sufficient transmission exists for every resource to deliver up to its firm capacity injection rights.

Not all intermittent resources choose to pay for transmission upgrades to achieve firm rights up to their nameplate capacity, relying partially on non-firm energy injection rights. Some parties argue that the probabilistic resource adequacy model (and accreditations) should limit the simulated hourly output to the firm level,[26] although we believe that is misguided. In fact, non-firm capacity is available most of the time except under infrequent transmission outages that are uncorrelated with supply shortage conditions. The most accurate way to represent contributions to resource adequacy in this context is to count non-firm injections subject to (low) outage rates. Since resources economically compete for scarce firm + non-firm transmission and more will be curtailed at high penetrations, additional adjustments can be made as curtailments increase.

B. Accreditation as Marginal or Average ELCC

Accreditation should value each resource according to its contribution to the resource adequacy objective. That value is often expressed as the "effective load-carrying capability," reflecting the amount of (constant) load increase that resources enable, while maintaining the target level of reliability. It can be determined by running the model and adjusting supply or load until the target one-in-ten reliability is reached, then adding the resource and iteratively adding load until the target is reached again. A nearly-equivalent and more common approach is to run the model with the resource(s) in question and adjust supply or demand until the target is reached; then to remove the resource(s) and add back increments of perfectly-available supply until the target is reached again. The accreditation of the resource(s) is the amount of perfectly-available supply that was added.

[26] See for example, Ethan Howland, "PJM rejects generator trade group request to bar some renewables from capacity auction," Dive Brief, *Utility Dive*, February 15, 2022, updated March 7, 2022.

The result of such an analysis will depend on the system composition, particularly on complementary and competing resources across a diverse fleet. Resource adequacy is rife with synergies/antagonisms and is characterized by diminishing marginal reliability value when adding more resources whose unavailability is correlated with other similar resources. For example, intermittent renewable resources tend to generate at the same time and satisfy needs when they are all available, but not when they are not available. Shortages become more likely when they are not available. Solar resources provide an intuitive example of this: as shown in Figure 3 above, plentiful solar generation can satisfy the afternoon peak load and move the net peak into the evening as the sun sets. The more such correlated resources are added, the less likely the next unit is to help avoid shortages, hence less marginal ELCC, as illustrated with a declining marginal ELCC curve in Figure 4 below.[27]

Declining marginal value raises a question of how to accredit resources. Crediting resources according to their marginal simulated reliability value is straightforward. For example, if the next solar resource being added provides the same reliability value as a perfectly-available capacity resource with 20% as much nameplate capacity, then all solar resources would be awarded a 20% marginal ELCC rating. If all other resource types are similarly awarded marginal ELCC based on their incremental ability to avoid reliability events as compared to a perfectly-available resource, then capacity ratings and payment levels will exactly scale to each resource's contributed reliability. The proportional size of payments to each resource type will match their marginal reliability value and direct incentives toward the most reliable resources.

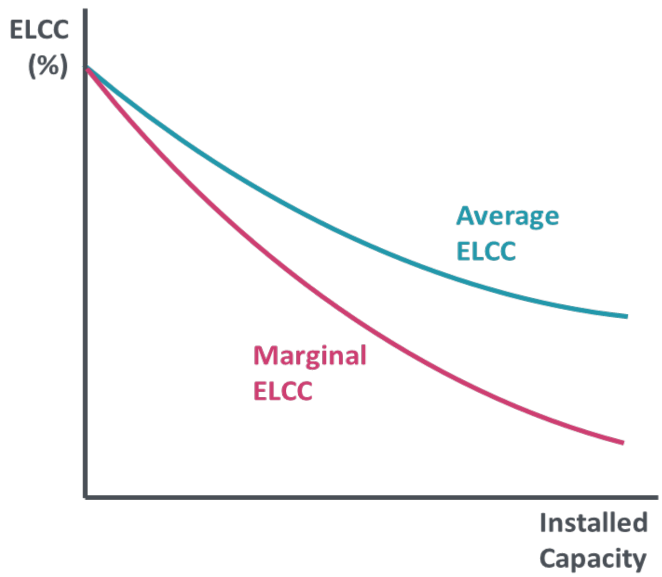
However, awarding the whole fleet at the marginal value does not recognize the cumulative value of correlated resources. For example, in a system with very high solar penetration, the fleet of solar plants greatly contributes to meeting the afternoon peak load. As a result, the afternoon peak no longer presents a reliability concern, and the period of greatest shortage risk shifts to a relatively smaller net peak load in the evening. The solar plants contribute little to serving that evening net peak, and so their marginal accreditation may be low. This means that generation sponsors that have paid for large amounts of such resources will be credited little for the value they provided to the rest of the system. This may seem counter-intuitive or unfair and has led

[27] The marginal ELCC of a given resource type may also depend on the penetration level of other resource types. These interactions across resource types, often called a "diversity benefit," may be synergistic or antagonistic depending on the nature of each resource type. Solar and battery resources are obviously synergistic. For another example, if wind resources tend to generate more at night, those resources will complement the attributes of solar resources, which produce during the day. All else equal, the marginal ELCC of solar would then *increase* as more wind is added (and vice versa). Alternatively, battery storage and DR resources both compete to flatten the net peak, so the marginal ELCC of battery storage will *decrease* as more DR resources are added (and vice versa). These interactions can be expressed in multi-dimensional surfaces analogous to the single-dimensional curve shown in Figure 4.

some renewable energy advocates to argue for accreditation being at the "average ELCC" reflecting the total value of a certain arbitrarily defined group of resources (*e.g.*, all solar or all renewable) resources provide, divided by their total nameplate capacity.

Under the average methodology, the total value can be measured by simulating the entire fleet (with small adjustments in load or generation until target reliability is reached) then removing a (arbitrarily selected) set of resources in question and substituting perfect capacity until the target is reached again; and the total value of that set is given by the amount of perfect capacity that had to be added.[28] The difference between marginal and average value can be large, as illustrated in Figure 4 below for a resource class with declining marginal value as depicted. The average value is higher than a declining marginal value, because it includes the higher marginal value of the first resources in the group as well as the lower marginal value of the last resources counted. As increasingly lower-value resources continue to come online, average ELCC will also decline but at a slower rate than marginal ELCC (see Figure 4). (Mathematically, the average value at any given quantity is the area under the marginal curve divided by the quantity).

FIGURE 4. ILLUSTRATIVE EXAMPLE: AVERAGE VS. MARGINAL ELCC



In comparing the merits of marginal vs. average approaches, only the marginal approach creates a **reliability-neutral exchange rate** among resources, which supports reliability, including when

[28] The choice of which resources to remove will affect the resulting total and average values. Some analysts have centered on removing all renewable resources, but that is as arbitrary as removing some of them or all resources. For more discussion of these concepts, see the section below on PJM's "average ELCC" approach.

Additionally, an average ELCC construct requires that the "diversity benefit" resulting from positive or negative synergies between resource classes be arbitrarily allocated amongst the different resource classes.

resource substitutions occur between the resource adequacy study and the capacity auctions. This allows the system operator to be indifferent as to which resource types clear the market, as the same level of reliability will be maintained.

The marginal approach also provides the economically efficient investment and retirement signals. New resources are compensated according to the actual reliability benefits they contribute, so a new resource will only be built if the value provided to the system exceeds the cost required to build the resource (when evaluated in combination with energy and ancillary services and any clean energy attributes). Existing resources are compensated according to the reliability benefits that would be lost if they retired. An existing resource will remain online only if the value provided to the system exceeds the cost required to stay online. The concept is the same as in any other industry where a factory producing widgets has the right incentives because it will be paid the market price (marginal value) of the widgets it will produce in every year (notwithstanding contracts that may hedge the risk around such fundamentals). Economic theory is clear that, absent market failures, such a system optimizes long-term social welfare.

In contrast, the average approach does not provide a reliability-neutral exchange rate or accurate investment signals. As the average approach does not accredit resources according to their marginal reliability value, any substitutions between resource classes may compromise reliability. For example, assume solar resources have a marginal ELCC of 20% but an average ELCC of 40%. If a 40 MW oil plant (assume 100% marginal ELCC) retires and is replaced by 100 MW of solar, the average ELCC construct would suggest that reliability is unchanged, when in reality, the 100 MW solar plant provides only half the reliability value that the oil plant did.[29] For that same reason, the average approach sends incorrect investment signals to investors. Using the same example, new solar resources are compensated as if they provide more incremental reliability value than they actually do. This over-compensation will lead investors to over-build solar resources relative to oil resources.

These conceptual advantages of the marginal ELCC approach are the primary reasons that PJM and New York market monitors have strongly advocated in favor of this approach, asserting that it is the only “right” approach. By contrast, the average ELCC approach can allow non-reliability neutral substitutions and incrementally incentivize investments in resources as if they provided substantially more reliability value than they actually do.

[29] The oil plant has a perfect capacity equivalent of 40 MW (40 MW nameplate times 100% marginal ELCC) while the solar plant has a perfect capacity equivalent of 20 MW (100 MW nameplate times 20% marginal ELCC).

We agree with the conceptual merits of marginal ELCC but caution that simulation-based marginal ELCCs can only be as good as the simulations. Simulation accuracy depends on many modeling choices and assumptions, such as selected weather years, modeling of fuel shortages and their durations, treatment of imports and external regions, granularity of dispatch modeling, and management of battery/hybrid resources. Another controversial topic is the treatment of resources that rely at least partly on non-firm transmission: the probabilistic simulations should recognize that non-firm transmission is usually available but for infrequent transmission outages that are likely uncorrelated with shortages. A careful examination of this issue is needed, along with the closely related issue of curtailments (including of thermal units dispatched down economically when transmission is limited in part because the wind/solar resource is using non-firm transmission). All of these choices should be transparent and subjected to sensitivity analyses and comparison empirical data.

Further, because both marginal and average ELCC values are developed for classes of resources to avoid conducting simulations for every individual resource, it becomes challenging to account for the wide variety of individual resource configurations, battery/hybrid resources' operational management choices, and other idiosyncratic factors that can impact resources' reliability value. Any approach should be refined or adjusted in light of resource-specific capabilities and operational performance, as discussed in the next section.

One implication of accrediting resources at only their marginal ELCC is that it can result in a total requirement and capacity supply obligations that may be less than the gross peak load + traditional reserve margin. This is because marginal accreditation reflects the ability of each generator to avoid load-shedding (which is its expected output during shortage conditions when each MWh of output avoids a MWh of load shedding); and aggregate accreditations must equal the load during those shortage events in order to avoid shedding load.

In a system where shortage risks occur when load is below peak load (as in New England winters, when gas-fired generation availability can plummet), the aggregate accreditation and thus aggregate nominal CSO could be correspondingly low. The figures below illustrate this point, with Figure 5 showing a traditional summer-risk system and Figure 6 showing a winter-risk system under a marginal accreditation framework. Similar but smaller mismatches between the accredited supply requirement and the peak load can occur within seasons or even intraday. For example, if shortage risks shift from gross peak to net peak (when load minus wind and solar output is greatest), a marginal accreditation framework will accredit and procure resource capacity to serve the need at the net peak. If the net peak is substantially lower than the gross peak, the resulting ICR and aggregate CSOs may be correspondingly low.

FIGURE 5. INSTALLED CAPACITY REQUIREMENT AND CAPACITY SUPPLY OBLIGATIONS IN A TRADITIONAL SUMMER-RISK SYSTEM

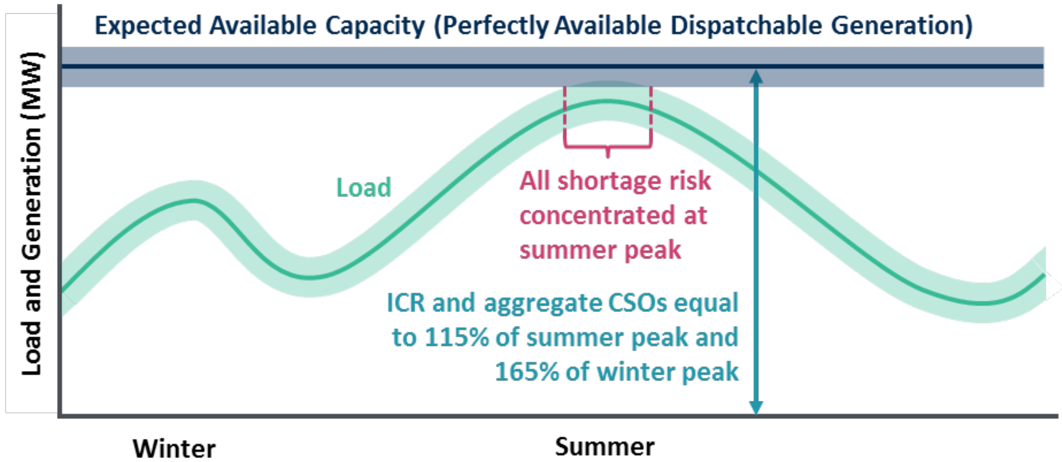
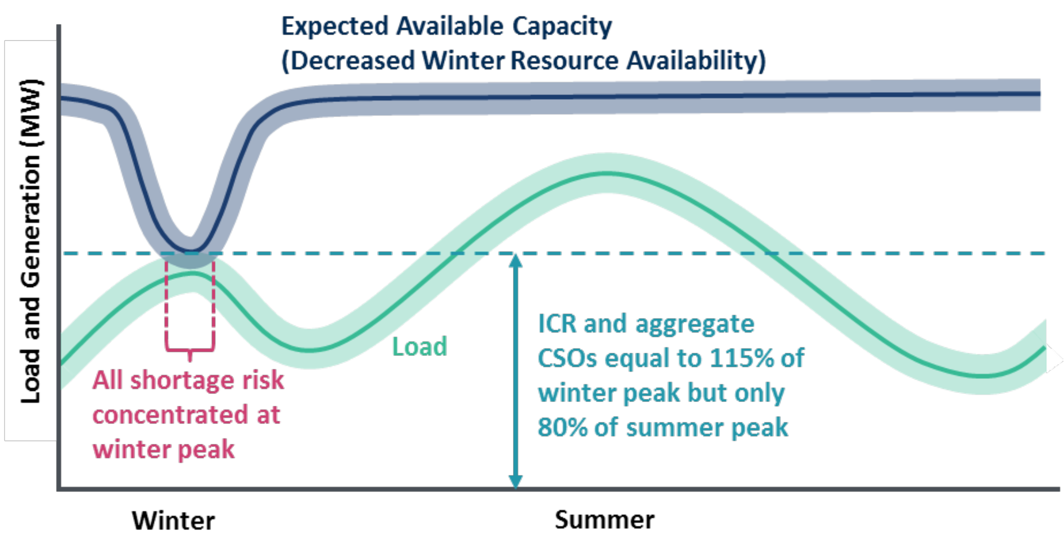


FIGURE 6. INSTALLED CAPACITY REQUIREMENT AND CAPACITY SUPPLY OBLIGATIONS IN A SUMMER-PEAKING BUT WINTER-RISK SYSTEM, UNDER A MARGINAL ACCREDITATION FRAMEWORK



The challenge this poses is that maintaining reliability all year, including at peak load periods, depends on resources delivering more MW than the nominal CSO for which they have been paid. Securing capacity commitments at MW volumes below gross peak load could make consumers, policymakers, and system operators less confident that sufficient capacity supply has indeed been secured and committed compared to what is needed for reliability. If the reliability modeling is accurate and abundant supply will be consistently available during times of gross peak load, then the fact that capacity commitments could be lower than gross peak load would be an optical problem but not a reliability problem. This could become a reliability problem (not just an optics problem) if the simulations are wrong and there is in fact risk during the gross peak load periods.[30] Thus we recommend examining whether and how often required supply deliveries might exceed the aggregate fleet-wide commitments to deliver that supply as nominally defined and paid for under the capacity obligation. If these occasions are few and far between, we anticipate this can be managed effectively through appropriate adjustments to the performance incentives framework. However, if these occasions are frequent, voluminous, or highly correlated among resources, the system could become unworkable.

This is not a reason to avoid marginal accreditation, but it does require that the Regional Transmission Organization (RTO) take steps to mitigate these risks. For cross-seasonal discrepancies, the RTO may need to split the annual resource adequacy construct into two seasons, thus enabling the resource adequacy construct to target the unique reliability risks in each season. For within-season issues, the RTO may need to adjust the way CSOs are defined. Whereas currently, each resource's CSO is equal to the quantity of cleared capacity, the CSO in a marginal approach could instead be defined as the expected 24-hour profile that was assumed in the resource adequacy modeling.[31] Additionally, the calculation of the balancing ratio should be revised such that it may exceed a value of 1. This is necessary to ensure that ISO-NE's Pay for Performance program is always fully funded, even in the event that gross load exceeds the CSO. If implemented properly, these two changes will resolve the intraday issue and ensure that CSOs always exceed forecasted and realized load.[32]

In addition to such reforms to the resource adequacy construct, energy scarcity pricing and the performance incentives framework should support reliability during realized shortages. Under

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[30] Simulations that do not identify risks at the gross peak load will suggest a target reserve margin below traditional peak load + reserve margin. No matter whether that reserve margin is expressed consistently with average accreditation or marginal accreditation, the actual fleet should match the simulated "reliable" fleet, which would be inadequate if there are in fact risks not captured in the simulations.

[31] This would involve scaling up the delivery obligations of those resources with declining marginal ELCCs (*i.e.,* intermittent, energy-limited, and non-firm fuel thermal resources) to their simulation-expected output each hour, as proposed by PJM's market monitor. Resources with declining marginal ELCCs are singled out because those resources are expected at times to generate more than the MW quantity of their marginal accreditation. Scaling CSOs is designed to align obligations with those expectations. Hourly scaling could reflect modeled conditions—not just for intermittent resources but also for non-winter-firm resources that are expected to produce at max capacity during summer peaks—and the scale-ups could be limited in aggregate to no more than the peak load + reserve margin, to still enable diversity sales across regions. However, that system results in a substantial differentiation in the assigned delivery obligations of different resources, which deviates from the goal of achieving a uniform capacity product regardless of underlying technology. See Monitoring Analytics, *ELCC—IMM Proposal*, August 12, 2020, p. 15.

[32] Modifying the CSOs to scale with the expected 24-hour profile of each resource is required to address the risks when load and generation behave as-expected. Allowing the balancing ratio to exceed 1 is required to address the risks when conditions are tighter than expected (as may arise during extreme heat or cold).

ISO-NE's Pay-for-Performance system, resources' obligation to deliver capacity scales with the size of load plus reserves during shortage events. As of the 2026/27 delivery year, resources that over-perform their capacity obligations will be awarded bonus payments of $9,337/MWh, while resources that under-perform will be penalized $9,337/MWh.[33] This design provides a strong incentive for an individual resource to meet and exceed its capacity obligations in all situations, including at times that are not precisely predicted by ISO-NE's modeling or the capacity accounting framework. Performance Incentives can incrementally improve and counteract imprecisions in ELCC-based resource accounting, but are not a robust solution to large, frequent, and highly correlated discrepancies between reliability needs and accounting outcomes.[34]

C. Class Ratings and Individual Resource Adjustments

As described above, the Average ELCC method necessarily contemplates a group of disparate resources within a class whose value would be assessed together, and then averaged. While a marginal ELCC could in theory be calculated for each individual resource, computational limitations likely require that resources be assessed by class.[35] In either case, assigning the same value to all resources in a given class would be inaccurate, given each resource's unique technologies, configurations, innovations, and operations causing different abilities to reduce

[33] *See* Market Rule 1, Section III.13.7.2.

[34] We view performance incentives alone as insufficient to make up for large, systematic capacity accounting errors for several reasons. First, reliability events have been infrequent enough that any under-performance penalties have been too small to substantially incentivize accurate self-discipline against excess capacity sales. Second, in any scenario where reliability events occur at times when load + reserves exceed committed capacity, the obligation to deliver capacity would exceed the MW volume of capacity commitments that an individual resource has been paid to deliver, a situation that may prove untenable if it were to become a regular occurrence. Third, some resources are likely to naturally provide supply in excess of their ELCC on many occasions (such as intermittent solar and wind, whose ELCC-based values are substantially below nameplate ratings), but others are not physically capable of excess deliveries (such as thermal resources whose capacity obligation is close to their maximum output rating). Fourth, large, frequent discrepancies where supply needs exceed resources' collective obligations could create situations with large non-delivery penalties that trigger the stop-loss mechanism (meaning that the penalty for under-performance is weakened, and the incentives for over-performance are similarly under-funded). Fifth, as we have observed in Texas as an outcome of hurricane Uri, it is possible that market participants, regulators, and RTOs can all collectively underestimate the size of severe reliability events and their associated financial implications, which suggests that a proactive approach to documenting and preventing such severe events cannot rely on probabilistic financial incentives alone.

[35] Both the marginal and average ELCC approaches may require grouping of like-resources (*e.g.,* all solar resources being assessed together), but the selection of resource classes in a marginal approach is less consequential than in an average approach. This is because the average approach requires an initial foundational step of selecting a super group of resources whose total value will be shared among the sub-classes and individual resources. This selection is inherently arbitrary and yet significantly impacts the ELCC values for each class (because it impacts the degree to which positive or negative synergies between resource types are captured in the modeling).

shortages. Individualized adjustments are necessary and could be implemented in numerous ways. For example, PJM has adopted an approach (detailed in Section IV.B) that allocates each resource class's total ELCC to individual resources according to each resource's demonstrated performance during the top 200 gross load and net load hours of the last 10 years. Note that these individualized resource adjustments can true-up capacity ratings amongst resources within the affected class of resources, but do not help to true-up capacity ratings as compared to resources outside the relevant resource class(es).

A slightly modified marginal ELCC method could in principle be applied to every individual resource without conducting model runs for each resource (thus circumventing the computational limitations mentioned above). This modified approach would involve simulating many weather years in order to quantify a probability of lost load (POLL) for each simulated hour. Then multiplying the corresponding hourly putative performance of each resource by the hourly POLLs will yield an estimate of the marginal unserved energy avoided by the resource in question (a reasonable proxy for marginal reliability value even if reliability is usually defined in terms of loss-of-load expectation). Finally, resources would be accredited according to how much they reduce the expected unserved energy (EUE)[36] relative to an equivalent nameplate quantity of perfectly-available capacity. Every resource would thus be credited in proportion to the (probability-weighted) expected value of its output during shortages. This is equivalent to the expected load-shedding the resource would avoid (since during a shortage every MWh of output during a shortage avoids 1 MWh of load-shedding), which can be referred to as each resource's marginal expected unserved energy (marginal EUE) value.

D. Accreditation Based on Historical Tight-Intervals Measurements

Observations of resources' actual performance or availability under various conditions can inform the probabilistic modeling used to set reserve margin requirements and accreditations. They can also be used directly for accrediting resources at their average output during shortage conditions, assuming recent history is representative of future conditions. The latter is a strong assumption, since usually weather patterns and occurrence of extremes vary year-to-year, so the most recent year or few years is not likely to be fully representative. Suppose, for example (exaggerated for illustrative purposes), that all of the risk is in one extreme 1-in-10-year event with no other load-shedding or near shortages. If a particular resource will fail under those

[36] EUE is a resource adequacy metric calculated as the number of MWh of demand expected to go unserved in a given year as a result of insufficient supply (load shed).

extreme conditions, such that its expected contribution to avoiding load-shed is 0, its resource adequacy value should always be 0 if the objective is only to avoid load-shed. Using only a 3-year sample will often falsely accredit the resource at 100% (whenever the extreme 1-in-10-year event is absent from the 3-year sample).

An additional challenge with a historical tight-intervals measurements approach is selecting the exact right hours/intervals to include in the assessment. Using the above example, assume that resources are instead accredited based on a 10-year historical sample (such that the 1-in-10-year event is always included in the sample). If the risk is concentrated in a single 10-hour period, only those 10 hours inform the resource's reliability value. Yet if the methodology accredits resources according to their performance in the 50 tightest hours of the last 10 years, there will be 40 irrelevant (*i.e.,* no shortage risk) hours diluting the impact of the 10 relevant hours, falsely accrediting the resource at 80% instead of 0. Worse yet, if the methodology accredits resources according to their performance in the 50 tightest hours of *each* of the last 10 years, the resulting credit will be 98% (*i.e.*, (0 + 490)/500). These effects will tend to over-credit resources on average, albeit not as much as in this illustrative example, with volatility that can at times under-credit them. And some resources can also be unfairly discredited if their performance was poor for idiosyncratic reasons during key measurement periods or if they have improved their operations since then. These potential downsides for resource owners can create pressure to broaden the sample of measurement hours, which can increase over-accreditation concerns described above.[37]

Yet there are three advantages of setting accreditations directly from performance: (1) it captures real-world conditions that may be missed if the modeling is overly idealized, particularly with respect to resource performance under challenging conditions; (2) it accounts for how a resource actually performed, given its physical attributes, maintenance management, fuel management, and any other measures the plant owner can take to enhance availability during shortages[38]; and (3) it provides incentives to manage availability better so as to earn higher capacity accreditation in future years. Incorporating elements of performance-based accreditation is especially important for traditional thermal resources, whose performance is strongly affected by these management factors, not just weather distributions.

[37] In its recently proposed thermal resource accreditation approach, MISO seeks to strike a reasonable balance. For each year and season in the sample, measurement hours include the 65 tightest operating margin hours, subject to a maximum operating margin of 25%. The sample will include any and all "MaxGen" hours (*i.e.,* hours with zero operating margin), even if there are more than 65 MaxGen hours. This approach allows the sample to include less than 65 hours in a season with minimal shortage risk or more than 65 hours in a season with very high shortage risk.

[38] Where available, actual observations are superior to simulated values because simulation models cannot possibly account for all operational differences, especially for thermal, hydro, battery, and hybrid resources.

Overall, we emphasize that, whether using a historical empirical approach or data-driven ELCC modeling, the model should be as realistic and representative as possible based on empirical observations of both weather and recent resource performance. Such empiricism must be incorporated one way or another, regardless of the broader modeling approach.

IV. Relevant Case Studies

This section describes the experiences of several other North American RTOs in refining their capacity accreditation methods. These case studies provide several important takeaways for ISO-NE. For convenience, we also include a summary overview of ISO-NE's current resource accreditation approach.

The average ELCC approaches employed by CAISO, PJM, and MISO provide informative examples of the granular details of ELCC modeling and implementation. The complex and contentious design processes that CAISO and PJM went through regarding the allocation of diversity benefits between resource classes offers a glimpse of the pitfalls of this arbitrary process (which is required under an average approach). CAISO's use of marginal ELCC for resource planning decisions is consistent with the idea that marginal accreditation sends the right investment signals to produce economically efficient levels of investment and resource build-out. MISO and Alberta's tight-intervals accreditation approaches, as well as the resource-specific performance adjustments used in MISO and PJM's ELCC approaches, provide an opportunity to conceptually consider what an optimally designed empirical approach might look like. An optimal approach must find a way to maximize the observed sample size (to consider as many weather years as possible) and to appropriately weight observations according to the corresponding loss-of-load probabilities (or a proxy). Such an empirical approach would be required if ISO-NE pursued a historical tight-intervals measurements approach or a resource-specific performance adjustment in an ELCC framework.

TABLE 1. OVERVIEW OF CAPACITY ACCREDITATION METHODS BY JURISDICTION

	Accreditation Periods	Accreditation Units of Measurement	Accreditation Approach for Different Technologies				
			Wind	Solar	Storage	Hybrid	Thermal
CAISO	Monthly	ICAP	**Average ELCC** for RA (Marginal ELCC for IRP)		Tested max deliverable output; 4-hour req.	Constrained sum-of-parts	Tested max deliverable output
PJM	Annual	UCAP	Implementing **Average ELCC**				EFORd-based
Alberta (Canceled)	Annual	UCAP	Capacity factor in tightest hours		Tested max deliverable output; 4-hour req.	N/A	Availability in tightest hours
MISO	Proposed: **Seasonal (4 seasons)**	UCAP	**Average ELCC**	Output in pre-defined peak hours	EFORd-based; 4-hour req.	Performance in prior year's 8 highest daily summer peaks	Current: EFORd-based Proposed: Performance in tight hours
SPP	**Seasonal (2 seasons)**	ICAP	Proposed **Average ELCC** pending approval		Tested max deliverable output; 4-hour req. Studying ELCC	Constrained sum-of-parts	Tested max deliverable output
NYISO	Monthly	UCAP	Capacity factor during pre-defined peak hours		Based on simplified average ELCC and EFORd	Constrained sum-of-parts	EFORd-based
			Future: developing **Marginal ELCC** or Marginal Reliability Improvement (MRI) for renewables, storage, hybrids and possibly some thermal resources.				
ISO-NE	Annual	ICAP	Capacity factor during pre-defined peak hours		Tested max deliverable output; 2-hour req.	Constrained sum-of-parts	Tested max deliverable output
			Future: developing **Marginal ELCC** or Marginal Reliability Improvement (MRI) for renewables, storage, hybrids and possibly some thermal resources.				

Source: Brattle research and analysis of RTO information, from sources as cited in the sections below.

A. ISO-NE's Current ICAP and Demonstrated Performance Approach

In ISO-NE, the capacity market utilizes an installed capacity (ICAP) accounting convention, in which traditional thermal generators and energy storage resources have capacity accreditation based on maximum output during peak demand conditions, subject to a 2-hour delivery requirement.[39] Under the ICAP accounting convention, generators' outage rates and fuel supply limitations are not considered in accreditation (although outage rates increase the resource adequacy requirement). Intermittent resources are accredited according to their median performance during pre-defined reliability hours (hours ending 18–19 in winter and 14–18 in

[39] ISO-NE, Market Rule 1, Section III.13.1.2.2.1.1.

ISO-NE, "Forward Capacity Market (FCM) Qualification Examples for Storage Technologies: Examples for Participation," March 2018.

summer, plus any system-wide scarcity condition hours), averaged across the previous five years.[40] Hybrid resources are subject to a constrained sum-of-parts accreditation methodology.[41] For all resource types, capacity ratings are calculated in both the summer and winter seasons, with the lower of the two values awarded as the resource's capacity value.[42]

B. CAISO's Approach Using both Average and Marginal ELCC

In California, thermal resources are accredited according to their tested maximum deliverable output, without accounting for EFORd.[43] Prior to adopting an ELCC approach, the CPUC relied on an "exceedance" methodology to establish net qualifying capacity (NQC) values for wind and solar resources for the resource adequacy program.[44] Under this approach, wind and solar generators were accredited according to the 30th percentile of their historical generation during peak hours (1 p.m. to 6 p.m. in summer and 4 p.m. to 9 p.m. in winter).[45]

In 2011, the state legislature directed the California Public Utilities Commission (CPUC) to implement an ELCC methodology, codifying a mandate to "maintain electric service reliability and to minimize the construction of fossil fuel electrical generation [needed to support renewable integration]."[46] Developing and implementing ELCC took significantly longer than expected, and it was not until 2017 that the CPUC finally approved ELCC for the resource adequacy program, to take effect in compliance year 2018.[47]

California has a unique approach to capacity accreditation because their resource adequacy and resource planning systems are bifurcated. Unlike in other RTOs, resource planning is a centralized process whereby the state Commission assesses the need and directs utilities to procure specified quantities and types of capacity. Resource adequacy is achieved through a separate

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40 ISO-NE, Market Rule 1, Section 13.1.2.2.2.

41 ISO-NE, "Forward Capacity Market (FCM) Qualification Examples for Storage Technologies: Examples for Participation," March 2018, p. 8.

42 Resource owners can also engage in bilateral agreements to pair complementary summer and winter resources, so as to submit a higher aggregate annual capacity rating.

43 CPUC, *2020 Qualifying Capacity Methodology Manual*, November 2020, p. 12.

44 CPUC, "Qualifying Capacity Methodology Manual Adopted 2015," Final, R.14-10-010, pp. 8–14.

45 *Ibid.*

46 California Senate Bill X1-2, FindLaw, California Code, Public Utilities Code – PUC § 399.26 (d)

47 CPUC, Decision 17-06-027, Decision Adopting Local and Flexible Capacity Obligations for 2018 and Refining the Resource Adequacy Program, June 29, 2017, Issued July 10, 2017, p. 21.

load serving entity (LSE) capacity obligation, whereby each LSE must bilaterally procure sufficient capacity to cover its own load.

This split approach allows the state to utilize two distinct resource accreditation methods, each serving a unique purpose. For resource planning, the state employs a *marginal* ELCC approach that properly values the reliability contributions of new incremental resources and informs optimal investment directives. For resource adequacy, the state utilizes an *average* ELCC approach that allows for (1) each resource to be accredited for its share of the total reliability contribution of its class, and (2) a static planning reserve margin that does not decrease alongside renewable penetration.

For its resource adequacy program, California currently calculates monthly average ELCC values for solar, wind, and certain hybrid resources.[48] (Standalone storage resources are not subject to ELCC and instead receive accreditation equal to the maximum output that can be sustained for four hours.[49] However, storage is included in the ELCC analysis of wind and solar to account for the diversity benefit that storage provides.[50]) The combined diversity benefit of the solar/wind/storage portfolio is allocated to each resource class in proportion to the standalone ELCC of each class.[51] This is an interim step—solar, wind, and storage are all assigned a share even though storage will not actually receive its share. Then subsequently, recognizing that storage resources predominately charge during periods of excess solar generation, the storage class's share of the diversity benefit is allocated to the solar class.[52]

The resulting perfect capacity equivalents of the solar and wind classes are then divided by the total nameplate capacity of each class to calculate monthly ELCC percentages. Then for every individual solar or wind resource, Net Qualifying Capacity (NQC) values are calculated as nameplate times ELCC percentage.[53] There is no resource-specific adjustment to account for performance differences within a given class.[54]

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48 CPUC, *2020 Qualifying Capacity Methodology Manual*, November 2020, pp. 13–14; 19.

49 CPUC, *Energy Division Monthly ELCC Proposal for 2020 RA Proceeding*, Rev. February 5, 2019, p. 7.

CPUC, Decision 19-06-026, Decision Adopting Local Capacity Obligations for 2020–2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program, June 27, 2019, Issued July 5, 2019, p. 48.

50 CPUC, "2020 Qualifying Capacity Methodology Manual," November 2020, pp. 13–14.

51 CPUC, "Energy Division Monthly ELCC Proposal for 2020 RA Proceeding," February 5, 2019, pp. 12–13.

52 *Ibid.*

53 CPUC, "2020 Qualifying Capacity Methodology Manual," November 2020, p. 14.

54 *Ibid.*

In 2020 the CPUC adopted a "sum-of-parts" methodology for calculating ELCC for hybrid resources receiving the Investment Tax Credit (ITC).[55] These resources require a special treatment because the ITC requires that the storage component charge exclusively from the co-located renewable component. The storage component is accredited at the lesser of: (1) nameplate capacity or (2) the amount of renewable charging energy transferred to the battery in the allotted time period divided by 4 (if the battery is not expected to fully charge).[56] The renewable component is accredited according to its class's ELCC percentage times the difference between its nameplate capacity and the capacity needed to charge the battery at a constant rate over the available charging hours.[57]

A recent stakeholder engagement at the CPUC prompted discussion and study of potentially: (1) transitioning to a marginal ELCC approach, (2) calculating ELCC for standalone storage, and (3) developing more granular resource classes (both locational and technological).[58] The CPUC declined to order any changes but acknowledged the merit of supporting arguments and ordered further study.[59]

The CPUC calculates resource adequacy ELCC values using SERVM, the same model it uses to calculate marginal ELCC values for Long-Term Procurement Planning.[60] Recent historical weather, load, and resource performance data are used to train a neural network model to create predictor relationships, allowing the model to create load and generation shapes for weather years dating back to 1980.[61] The CPUC analyzes five load forecast error scenarios for each weather year.[62] Each scenario and weather year is probabilistically weighted so as to produce a

[55] *Id.*, p. 19.

[56] *Ibid*.

[57] CPUC, "2020 Qualifying Capacity Methodology Manual," November 2020, p. 19.

[58] CPUC, Decision 20-06-031, Decision Adopting Local Capacity Obligations for 2021-2023,Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program, June 25, 2020, Issued June 30, 2020, pp. 33–36.

[59] *Ibid*.

[60] CPUC, *Proposal for Monthly Loss of Load and Solar and Wind Effective Load Carrying Capability Values for 2018 Resource Adequacy Compliance Year*, Resource Adequacy Proceeding R.14-10-010, February 24, 2017, p. 8; and CPUC, Decision 17-06-027, Decision Adopting Local and Flexible Capacity Obligations for 2018 and Refining the Resource Adequacy Program, June 29, 2017, Issued July 10, 2017, p. 21.

[61] CPUC, "Proposal for Monthly Loss of Load and Solar and Wind Effective Load Carrying Capability Values for 2018 Resource Adequacy Compliance Year," February 24, 2017, p. 9.

[62] *Id.*, p. 11.

single weighted average loss of load expectation (LOLE).[63] Transmission constraints are modeled, but ELCC results are not at present differentiated by geography.[64]

C. PJM's Average ELCC Approach

PJM is currently implementing reforms to its accreditation, and we'll start with a description of its old approach (still in effect), then describe its reforms.

Until those reforms have been implemented, PJM continues to accredit thermal resources according to their maximum capability in summer peak conditions, discounted for EFORd.[65] Storage resources are accredited at the maximum capability that can be sustained for 10 hours during conditions consistent with the summer peak.[66] Wind and solar resources are accredited according to their demonstrated capacity factor during summer peak hours (2–6 p.m. from June 1 to August 31).[67] For each resource, PJM calculates an annual average summer peak capacity factor for each of the last three years. For years where data is unavailable, PJM will use the class-average capacity factor.[68] Then for each resource, PJM calculates a 3-year capacity factor equal to the mean of the calculated single year capacity factors for the previous three years.[69] The unforced capacity value (UCAP) of each resource is calculated as that resource's 3-year capacity factor times its nameplate capacity.[70] All accredited resources are subject to verification testing.[71]

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63 *Ibid.*

64 *Ibid*.

65 PJM, "PJM Manual 18: PJM Capacity Market," Revision 52, February 24, 2022, p. 121.
PJM, "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Rev. 13, Effective Date: May 1, 2019, p. 25.

66 PJM, "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Rev. 13, Effective Date: May 1, 2019, p. 25.

67 PJM, *PJM Manual 21: Rules and Procedures for Determination of Generating Capability*, Rev. 16, Effective Date: August 1, 2021, pp. 36–37.

68 *Ibid*.

69 *Ibid*.

70 *Ibid*.

71 PJM, "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Rev. 13, Effective Date: May 1, 2019, p. 16.

In 2020, PJM set out to develop an ELCC-based approach for wind, solar, storage, and hybrid resources.[72] This initiative was motivated by a recognition that the current capacity accreditation approach may not be sufficient in a high-renewable future. Specifically, PJM stated that the current approach cannot adequately measure a resource's contribution to resource adequacy because it does not capture the impact of correlations among resources and the overall fleet. This deficiency becomes more pronounced alongside growing penetration of correlated intermittent resources. PJM also identified a need to phase out its 10-hour duration requirement for storage resources, and ELCC provides an opportunity to accurately assess the contributions of shorter-duration storage.

During the stakeholder process, PJM's independent market monitor (IMM) proposed a marginal ELCC approach, emphasizing that the capacity market should maximize consumer welfare by establishing efficient investment signals for market entry and exit.[73] According to the IMM, an average ELCC approach will over-procure and overpay intermittent resources while inefficiently displacing traditional resources.[74] Interestingly, the IMM proposed that intermittent resources' performance obligations be defined as their expected 24-hour generation profile.[75] This approach avoids the potential issue of peak load exceeding the aggregate CSOs (described in Section III.B), but it means that intermittent resources may at times be obligated to produce more MW than they offered into the capacity market.

Many of PJM's incumbent renewable generators expressed a preference for an average approach that would accredit the overall portfolio of ELCC resources for its total contribution. These stakeholders argued that the primary function of capacity accreditation is to ensure reliability (which the average approach basically does as long as the requirement itself is expressed in consistent terms); they argued that producing efficient signals for market entry and exit was not a primary purpose of accreditation.[76] Several stakeholder groups (primarily renewable/storage owners and operators) additionally lobbied for a transition mechanism that would establish class rating floors for ELCC resources on a rolling annual basis for 13 delivery years following market

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72 PJM, "Problem/Opportunity Statement: Effective Load Carrying Capability for Limited Duration Resources and Intermittent Resources," April 7, 2020, p. 1.

73 Monitoring Analytics, *ELCC—IMM Proposal*, August 12, 2020.

74 *Id.*, p. 17.

75 *Id.,* p. 15.

76 PJM filing letter *re* Effective Load Carrying Capability Construct in FERC Docket No. ER21-278-000, October 30, 2020, p. 23.

entry.[77] Proponents argued that the transition mechanism was necessary to limit uncertainty and volatility in class ELCC values.

PJM staff endorsed the stakeholder proposal and in October 2020 filed tariff revisions to implement an average ELCC approach as well as the proposed transition mechanism.[78] The FERC rejected PJM's initial filing, citing the unjust and unreasonable transition mechanism that would discount certain resources' capacity accreditation below their actual capacity value in order to accredit other resources above their actual capacity value.[79] PJM then refiled the tariff revisions without the transition mechanism and received FERC approval in July 2021.[80] Notably, in its order accepting PJM's proposal, the FERC stated that, "while a marginal approach may also be designed in such a way that it is just and reasonable and not unduly discriminatory, that fact does not render PJM's proposed average approach unjust and reasonable."[81] PJM's now-approved ELCC methodology will employ an average ELCC approach for wind, solar, storage, hybrids, and hydropower resources. PJM has yet to fully define the specific resource classes, but has stated they will consist of resources that are "reasonably homogeneous in character and with respect to impact on system [resource adequacy]"[82] PJM's filing also indicates that storage resources and hybrid storage resources will be segmented by duration (durations of 4, 6, 8, and 10 hours). Hydropower resources with non-pumped storage often have unique characteristics that prevent them from being modeled as a class. As such, these resources will be modeled on an individual basis.[83] At present, PJM's average ELCC methodology will not apply to dispatchable non-energy limited resources, but PJM is now considering extending ELCC to all resource types.[84]

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77 PJM, *Joint Stakeholder Transition Package*, PJM Markets & Reliability Committee Special Session: Capacity Capability Senior Task Force, September 17, 2020, pp. 5–7.

78 PJM filing letter *re* Effective Load Carrying Capability Construct in FERC Docket No. ER21-278-000, October 30, 2020.

79 175 FERC ¶ 61,084, Order Rejecting Proposed Tariff Revisions, Lifting Paper Hearing Abeyance, and Establishing Briefing Schedule, April 30, 2021, P 17.

80 176 FERC ¶ 61,056, Order Accepting Tariff Revisions and Terminating Section 206 Proceeding, July 30, 2021, P 3.

81 *Id.*, P 37.

82 PJM filing letter *re* Effective Load Carrying Capability Construct in FERC Docket No. ER21-278-000, October 30, 2020., p. 16.

83 *Id.*, p. 42.

84 PJM, *Capacity Market Reform: Phase 2*, Capacity Market Workshop #9, September 28, 2021, p. 5, available at:.

PJM's average ELCC approach aims to decompose the total portfolio ELCC into individual resource class ratings that reflect each class's contribution, including interactions with other classes, using a three-step "Delta Method".[85] Those steps are as follows:[86]

1. PJM calculates the Portfolio ELCC (combined ELCC of all ELCC resource classes).

2. PJM calculates a First-In and a Last-In marginal ELCC for each resource class. The First-In ELCC for a given resource class is the ELCC of a 1 GW increment of that class when added to a portfolio exclusive of all ELCC resource classes, scaled up to the size of the resource class. The Last-In ELCC for a given resource class is the ELCC of a 1 GW increment of that class when added to a portfolio inclusive of all ELCC resource classes (including the resource class in question), scaled up to the size of the resource class. The First-In ELCC is essentially the marginal ELCC for a given resource type if it were the first GW of any ELCC resource type to come online. The Last-in ELCC is the marginal ELCC for a given resource type, where it is the very last GW to come online. As ELCC resources all have declining marginal ELCCs, the First-In ELCC will typically (but not always) be larger than the Last-In ELCC. The Last-In ELCC may be larger than the First-In ELCC if there are significant synergies between resource types (*e.g.,* if storage becomes more valuable when there is solar on the system).

3. PJM then calculates the Total Delta ELCC, which is equal to the difference between the sum of all Last-In ELCCs and the sum of all First-In ELCCs for all ELCC resources. For each resource class, the Delta ELCC is equal to the difference between that resource class's Last-In and First-In ELCC. Then the MW difference (positive or negative) between the portfolio ELCC and the sum of all First-In ELCCs is allocated to each class in proportion to that class's Delta ELCC relative to the Total Delta ELCC. Each class's final ELCC Class Rating is equal to its First-In ELCC plus its share of the MW difference between the portfolio ELCC and the sum of all First-In ELCCs.

For each individual resource, PJM calculates an accredited UCAP value by multiplying the resource's nameplate capacity by the ELCC Class Rating described in Step 3 above and by a resource-specific performance adjustment.[87] The resource-specific performance adjustment is a factor designed to account for the resource's individual performance relative to its class. These

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[85] 176 FERC ¶ 61,056, July 30, 2021, P19.

[86] Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-2043-000, June 22, 2021, p. 15; and PJM, *Delta Method—Step-by-Step Guide*, February 18, 2021, available at:.

[87] PJM filing in FERC Docket No. ER21-278-000, October 30, 2020, p. 34.

performance adjustment factors are scaled such that the sum of accredited UCAP values for all resources in a given class equals the total ELCC Class Rating.

For limited duration resources, non-intermittent hybrid resources (*i.e.,* any hybrid resource where neither component is intermittent), and hydropower resources with non-pumped storage, the resource-specific performance adjustment will simply be 1 minus EFORd.[88] For intermittent resources, the resource-specific performance adjustment will be based on each resource's performance in the 200 highest putative net peak load hours (proxy for Last-In contribution) and 200 highest peak load hours (proxy for First-In contribution) from the previous 10 years.[89] Each intermittent resource's performance adjustment will equal its average capacity factor in those 400 hours divided by the weighted-average capacity factor of the entire class in those same hours.[90]

Accreditation of intermittent hybrid resources in PJM follows a sum-of-parts methodology. For each class of intermittent hybrid resources (*e.g.* solar with 4 hour storage or wind with 8 hour storage), PJM will calculate a total ELCC Class Rating. The intermittent component of the hybrid's accredited UCAP will be calculated as the product of (1) the applicable intermittent resource ELCC Class Rating, (2) the effective nameplate capacity of the intermittent component, and (3) the resource-specific performance adjustment based on the directly measured output of the intermittent component (and calculated as for any other intermittent resource). The limited duration component of the hybrid's accredited UCAP will be calculated as the product of the equivalent effective nameplate of the storage component and (1 minus the applicable EFORd), adjusted *pro-rata* such that the sum of all hybrid accredited UCAP values in the class equals the total ELCC Class Rating.[91]

PJM has not yet specified which model and software it will use to perform ELCC calculations, but it will differ from that used for the Reserve Requirement Study.[92] The ELCC model will rely on weather data dating back to June 2012, so as to include only years with substantial wind/solar

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88 *Ibid*.

89 Putative net peak load is defined as actual load minus the putative hourly output of variable resources based on the resource mix of the target year.

See Id., p. 35.

90 *Ibid*.

91 *Id.*, pp. 40–41.

92 Affidavit of Dr. Patricio Rocha Garrido on Behalf of PJM Interconnection, L.L.C., October 28, 2020, p. 14 (p. 280 of pdf), Attachment C (p. 266 of pdf) to PJM filing letter *re* Effective Load Carrying Capability Construct in FERC Docket No. ER21-278-000, October 30, 2020. ("Garrido Affidavit").

performance data.[93] Hourly load shapes will be generated by inputting historical weather data into PJM's load forecast model, with 1,000 variation scenarios generated for each weather year.[94] PJM calculates a probability of each historical weather year so that all years may inform a single weighted LOLE value.[95]

Hourly variable generation output will be based on historical and putative generation data for each weather year.[96] Putative generation data is also calculated for modeled resources without historical data, based on historical weather data consistent with each resource site.

Storage resources will be modeled using non-economic simulation of charging and dispatch, with zero foresight.[97] The model assumes that storage resources will charge whenever available unlimited and variable generation exceeds load, subject to applicable constraints (*e.g.,* ability to charge using grid power, limited inverter capacity).[98] The simulation dispatches storage resources after unlimited and variable resources, but before deploying DR.[99]

Transmission constraints and curtailments are not considered in the probabilistic modeling. The underlying assumption is that the Regional Transmission Expansion Plan (RTEP) process precludes any congestion-driven LOLE.[100]

D. Alberta's Proposed Top-250-Hours Accreditation

In 2017, the Alberta Electric System Operator (AESO) proposed and designed a capacity market construct, but the market was never implemented. In that design the AESO proposed to accredit capacity resources based on performance/availability during the 250 tightest supply cushion hours (*i.e.,* hours with the lowest amount of available excess capacity) in each of the previous 5

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93 PJM filing letter *re* Effective Load Carrying Capability Construct in FERC Docket No. ER21-278-000, October 30, 2020, pp. 25.

94 Garrido Affidavit, pp. 4–5.

95 *Id.*, p. 4.

96 *Id.*, p. 6.

97 Non-economic simulated charging and dispatch means that in the simulation, storage resources are dispatched/charged based on resource availability and need, rather than on economics. Zero-foresight means that the criteria for dispatch/charging depend only on instantaneous real-time conditions rather than expectations of future conditions.

98 *Id.*, pp. 8-9.

99 Garrido Affidavit, p. 8; and PJM filing letter *re* Effective Load Carrying Capability Construct in FERC Docket No. ER21-278-000, October 30, 2020, p. 29.

100 Garrido Affidavit, p. 13.

years.[101] The AESO's proposal stipulated that resources be accredited using the following methodology:

Intermittent resources would receive a UCAP value equal to their average capacity factor in those 1,250 tight supply cushion hours. Dispatchable resources (including storage) would receive a UCAP value equal to their average availability factor in those same hours.[102] Storage resource UCAP would be capped at the maximum output that can be sustained for four hours.[103]

For both dispatchable and intermittent resources, forced and planned derates and outages, distribution system constraints, transmission outages, and *force majeure* events would be included in the availability/performance data (*i.e.*, would reduce calculated UCAP values).[104] Transmission system constraints, however, would not be included in the availability factor calculation.[105]

For resources having fewer than five years of operational data, the UCAP calculation would use all available data, provided that available data exceeds the minimum requirement (data in at least 250 tightest supply cushion hours for dispatchable resources or 300 tightest supply cushion hours for intermittent resources). For resources not meeting that minimum requirement, UCAP would be determined using a combination of available data and class averages.[106]

One possible shortcoming of this approach is that by analyzing the top 250 hours in each year (as opposed to the top 1,250 hours in the previous five years), it may overweight hours that were relatively tight in a given year but not relative to the broader five-year period. For example, Figure 5 shows the average supply cushion in the tightest 100, 250, 500, and 1,000 hours for each year from 2012/13 to 2016/17. Using the tightest 250 hours from each year yields 1,250 hours with an average supply cushion of 538 MW. Note however that in 2012/13, the tightest 1,000 hours had an average supply cushion of 482 MW. The AESO methodology fails to recognize that the scarcity risk in this period was highly concentrated in a single year. As a result, this approach under-values performance in 2012/13 and over-values performance in all other years.

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[101] AESO, Overview of the Alberta Capacity Mark*et*, pp. 3-4.

[102] AESO, "Calculation of Unforced Capacity (UCAP)," pp. 2-3.

[103] AESO, "Overview of the Alberta Capacity Market," p. 2.

[104] Transmission outages defined as outages that result in an asset being electrically disconnected from the transmission system.

AESO, "Overview of the Alberta Capacity Market," p. 4.

[105] It is unclear if transmission constraints would also be excluded from the capacity factor calculation for intermittent resources.

[106] AESO, "Calculation of Unforced Capacity (UCAP)," p. 3.

FIGURE 7. DISTRIBUTION OF TIGHTEST SUPPLY CUSHION HOURS IN EACH YEAR

Hours per Capacity Interval	Average Supply Cushion (MW) 2012/13	2013/14	2014/15	2015/16	2016/17	Average
100	47	516	666	476	268	395
250	173	670	811	633	402	538
500	313	792	942	798	532	675
1000	482	929	1083	993	709	839

Data source: AESO, "Calculation of Unforced Capacity (UCAP)," p. 8.

E. Midcontinent ISO's New Seasonal Capacity Market with Average ELCC for wind

In MISO, thermal resources are currently accredited according to nameplate capacity discounted for EFORd.[107] Though it has not yet been approved, MISO recently filed with FERC to implement a new seasonal accreditation approach, where thermal resources would be accredited according to their historical performance during tight supply cushion hours.[108] MISO has employed an average ELCC approach for its wind resources since planning year 2011–12.[109] Though MISO and its stakeholders are beginning to discuss the possibility of introducing ELCC for solar and storage, those resources are currently subject to a historical performance-based accreditation.

Under MISO's current approach, solar resources receive a UCAP accreditation equal to their 3-year historical average output (with curtailments added to actual output) for hours ending 15, 16, and 17 for the months of June, July, and August.[110] For solar resources with less than three years but more than 30 days of summer performance data, MISO simply averages across fewer hours. Any solar resource with fewer than 30 days of summer performance data will receive the class average of 50% for its first year. The UCAP value of a storage or other use-limited resource is based on the resource's XEFORd[111] value and tested maximum output that can be sustained

[107] MISO, "Business Practices Manual 011: Resource Adequacy," December 15, 2020, Section 4.2.1.1, (see file "BPM-011-r25_Resource_Adequacy_clean.pdf).

[108] MISO, "Re: Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirement for the MISO Resource Adequacy Construct," November 30, 2021, p. 15.

[109] MISO, *Planning Year 2021–2022 Wind & Solar Capacity Credit*, Draft, December 2020, p. 10.

[110] MISO, "Business Practices Manual 011: Resource Adequacy," December 15, 2020, Section 4.2.3.3.2.

[111] XEFORd is a metric MISO uses that is equivalent to EFORd but calculated such that it excludes outages that are considered "Out of Management Control," such as transmission outages. *See* MISO, "Business Practice Manual 001: Resource Adequacy," Appendix I, December 15, 2020.

for four hours.[112] As with all other resources, solar and storage resources must meet certain deliverability criteria in order to convert UCAP into capacity credits (referred to as Zonal Resource Credits or ZRCs).[113]

Since MISO only calculates ELCC for a single class of resources, there are no diversity benefits to be allocated across classes. The fleet-wide wind ELCC is simply calculated as the difference in load-serving capability of the resource portfolio with and without the fleet of wind resources.[114] MISO conducts its ELCC study using SERVM. Model inputs include the actual historical hourly load and hourly wind output profiles. For each weather year dating back to 2005, MISO calculates a wind ELCC for the fleet that existed in that weather year. Then for each weather year, it scales up the wind profiles and recalculate the ELCC value each of for several different levels of penetration (30 GW, 40 GW, and 50 GW of installed wind). Each weather year now has 4 calculated values of wind ELCC. MISO then fits a trend line showing the correlation between wind penetration (installed wind capacity as a % of peak load) and ELCC (as a % of installed wind capacity) for each weather year. Next MISO inputs the current level of wind penetration into each of those polynomial functions to calculate an estimate of the current wind ELCC from each weather year. The final wind ELCC value (expressed as a percentage) is then calculated as the simple average of those estimates.[115]

MISO adopted a new process of allocating the fleet-wide ELCC for wind to individual resources in 2020.[116] The fleet-wide wind ELCC percentage is multiplied by the wind installed capacity to determine a MW quantity of fleet-wide wind capacity. Then for each wind resource, MISO calculates two allocation metrics. The first metric is based on each resource's average capacity factor over the top 8 daily peak hours for each year dating back to 2005, relative to the fleet-wide average capacity factor in those same hours. The second metric is the same, but with curtailments counted as output in the capacity factor calculations. Each resource's UCAP is calculated using whichever metric yields a higher UCAP value.[117]

The use of two different allocation metrics may lead to individual UCAP values that sum to a number higher than the calculated fleet-wide quantity, and this was indeed the case in planning year 2021–22. MISO calculated a fleet-wide ELCC quantity of 3,598 MW, but the individual

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112 MISO, "Business Practices Manual 011: Resource Adequacy," December 15, 2020, Section 4.2.4.2.

113 *See* MISO, "Business Practices Manual 011: Resource Adequacy," December 15, 2020, Appendix H and V.

114 MISO, "Planning Year 2011-2022 Wind & Solar Capacity Credit," Draft, December 2020, pp. 6–7.

115 *See Id.*, pp. 7–9.

116 *See* [173 FERC ¶ 61,139](), November 13, 2020.

117 MISO, "Planning Year 2021-2022 Wind & Solar Capacity Credit," Draft, December 2020, p. 12.

resource UCAP values summed to 3,661.[118] Resource UCAP values are subject to a deliverability requirement in order to be converted to ZRCs.[119]

F. SPP's Proposed Tiered-Average ELCC Approach

In SPP, thermal resources are accredited according to their tested maximum deliverable output, without derating for EFORd.[120] SPP currently accredits wind and solar resources according to the 60th percentile of generator output during the highest 3% of load hours of each month for a historical period of at least three years.[121] Recognizing the substantial growth in wind and solar resources in the region, SPP in 2018 began researching ELCC and assessing if its then existing methodology could threaten reliability.[122] Two 2019 investigative ELCC studies indicated substantial discrepancies between ELCC and the current framework. As a result, SPP approved ELCC as the guiding principle for wind, solar, and storage resources. SPP is now in the process of implementing a tiered average ELCC methodology for wind and solar resources, to take effect in 2023.[123]

SPP has stated that its tiered approach serves to encourage firm transmission service and prevent early adopters from overly depressing the capacity accreditation of Load Responsible Entities (LRE) implementing intermittent resources at a slower rate.[124] Each wind and solar resource on the system will be assigned to one of three tiers depending on: (1) whether the resource has firm transmission service rights and (2) the quantity of installed capacity (of that specific technology) to which the associated LRE owns the resource adequacy credits. The tiers are structured as follows:[125]

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[118] *Ibid*.

[119] *Id.*, pp. 13–14.

[120] SPP, "SPP Planning Criteria, Revision 2.4," February 4, 2021, Section 7.1.1.1.

[121] If the facility has been in operation for 3 years or less, it will be a 3-year evaluation period (using putative output where measured data is not available). If the facility has been in operation for more than 3 years, the evaluation period will be all years where data is available, up to a maximum of 10 years.

See SPP, *SPP Planning Criteria, Revision 2.4*, February 4, 2021, Section 7.1.2.10.

[122] SPP, *Wind and Solar Accreditation*, August 2019, p. 3.

[123] SPP, "Revision Request 418: Effective Load Carrying Capability Methodology for Wind and Solar Resource Accreditation," August 21, 2020, p. 6, (see file "RR418 SPP Comments 8 21 2020.docx).

[124] LREs in SPP are predominantly vertically integrated utilities.

[125] SPP, "Revision Request 418: Effective Load Carrying Capability Methodology for Wind and Solar Resource Accreditation," August 21, 2020, p. 6.

- Tier 1—New wind (solar) resources having firm transmission service will be assigned to Tier 1 until the associated LRE's owned wind (solar) capacity exceeds 35% (20%) of the LRE's average seasonal net peak load for the previous three years.
- Tier 2—New wind or solar resources having firm transmission will be assigned to Tier 2 only after Tier 1 is full.
- Tier 3—New wind or solar resources *not* having firm transmission will be assigned to Tier 3.

SPP will sequentially calculate separate class total ELCC values for each tier. For example, the ELCC of solar Tier 1 will estimate the capacity contribution of Tier 1 solar resources, where no other solar is modeled in the base case. The ELCC of solar Tier 2 estimates the capacity contribution of Tier 2 solar resources where all solar Tier 1 resources are included in the base case. The same approach is used for solar Tier 3 but solar Tiers 1 and 2 are included in the base case.

SPP has not proposed an interaction adjustment. In absence of such an adjustment, ELCCs for each resource type and tier will be standalone. The class total ELCC for each resource type and tier will be allocated to individual resources based on three years of historical or putative performance data. For Tiers 1 and 2, ELCC allocation is based on performance in the top 3% of the associated LRE's annual load hours. For Tier 3, allocation is based on performance during the top 3% of SPP system-wide load.[126]

Many details of SPP's ELCC modeling process have not yet been determined. SPP's tariff revisions stipulate that the Supply Adequacy Working Group will annually determine and approve the parameters of the ELCC Accreditation Study. SPP states that most of the inputs and assumptions will be consistent with the most recent LOLE study, but one notable difference is that transmission constraints will not be modeled in the ELCC study.[127]

While modeling details have not been formally codified, SPP has conducted several investigative ELCC studies that may offer some insights into their future modeling approach.[128] In those studies, SPP employed a similar model to their existing Reserve Margin study, with the main differences being that the ELCC studies did not model transmission limitations or load forecast

[126] SPP, "Wind and Solar Accreditation," August 2019, p. 13.

[127] SPP, "Revision Request 418: Effective Load Carrying Capability Methodology for Wind and Solar Resource Accreditation," July 30, 2020, p. 13.

[128] SPP, *ELCC Wind Study Report*, August 13, 2019.
SPP, *ELCC Solar Study Report*, 2019.
SPP, *2020 ELCC Wind and Solar Study Report*, July 2021.

uncertainty but did assess several scenarios of future nameplate wind and solar. In the 2019 studies, SPP modeled six weather years (2012–2017), each with multiple scenarios of pre-commitment outages and maintenance schedules as well as probabilistically weighted load forecast uncertainty levels. SPP calculated an ELCC for each weather year and then averaged the results. For sites with existing installed solar, SPP utilized historical solar generation data. For modeled regions without historical data, SPP relied on irradiance data and historical correlations to generate putative output profiles.

G. NYISO's Upcoming Development of a Marginal ELCC Approach

In NYISO, thermal resources are currently accredited based on nameplate capacity, derated for EFORd.[129] NYISO currently accredits intermittent resources on a seasonal basis according to their demonstrated capacity factor in the relevant Summer or Winter Peak Load Hours during the prior year's capability period. Summer Peak Load hours are from HE13 to HE18, and Winter Peak Load Hours are from HE16 to HE21, but not all hours are weighted equally.[130]

Prior to 2020, energy limited resources (*e.g.,* batteries or pumped hydro) received the same capacity accreditation as a comparable unlimited resource, provided that resource could operate for four continuous hours.[131] In 2019, as part of an initiative to improve the participation requirements for ICAP suppliers (*i.e.,* entities selling capacity into NYISO's ICAP market), NYISO hired GE Energy to assess whether the 4-hour requirement would be sufficient to guarantee resource adequacy in a high-storage penetration future.[132] GE Energy conducted a storage ELCC study that assessed the capacity value of various storage durations under several different levels of penetration.[133]

Based on the results of that study, NYISO designed and received FERC approval for a tiered approach that could accurately derate energy-limited resource accreditation based on resource-

[129] NYISO, "Installed Capacity Manual Attachments," December 15, 2021, Attachment J, Section 3.1.1.

[130] *See* NYISO, *Installed Capacity Manual Attachments*, December 15, 2021, Attachment J, Section 3.4(b).

[131] 170 FERC ¶ 61,033, "Order Accepting Tariff Revisions and Directing Compliance Filing and Informational Report," January 23, 2020, p. 33.

[132] NYISO filing in FERC Docket No. ER19-2276, June 27, 2019, p. 64.

[133] GE Energy Consulting, Valuing Capacity for Resources with Energy Limitations, January 8, 2019.

specific duration and the overall level of penetration.[134] These "duration adjustment factors" are applied to each energy-limited resource's maximum capability to calculate an adjusted ICAP. That adjusted ICAP is then derated according to a derating factor based on the resource's time-weighted upper operating limit availability evaluated against the quantity of ICAP sold.[135] NYISO's current duration adjustment factors are shown in Figure 6.

FIGURE 8.NYISO DURATION ADJUSTMENT FACTORS

	Incremental Penetration of Resources with EDLs	
	Less than 1000 MW	1000 MW and greater
Energy Duration Limitation (hours)	Duration Adjustment Factor (%)	Duration Adjustment Factor (%)
2	45	37.5
4	90	75
6	100	90
8	100	100

NYISO, "Amount of Capacity Qualified to Offer," June 23–24, 2021, p. 14.

In 2019, New York State approved ambitious climate goals and clean energy mandates that would greatly increase the amount of intermittent and energy-limited resources on the NYISO system. NYISO has indicated that its current accreditation methods may be insufficient to accommodate the scale of these mandates.[136]

NYISO therefore began engaging with stakeholders about possible implementation of an ELCC-based approach. NYISO's market monitor recommended a marginal approach: either marginal ELCC or Marginal Reliability Improvement (MRI).[137][138] NYISO subsequently submitted a filing with the FERC in January 2022 stating its intention to proceed with a marginal accreditation

[134] 170 FERC ¶ 61,033, "Order Accepting Tariff Revisions and Directing Compliance Filing and Informational Report," January 23, 2020, pp. 37–38.

[135] NYISO, Amount of Capacity Qualified to Offer, Intermediate ICAP Course, June 23–24, 2021, p. 31.

[136] NYISO, Capacity Accreditation: Straw Proposal, August 9, 2021, p. 7.

[137] MRI may be considered a sub-set of marginal ELCC and can be expected to yield very similar results. It relies on the same conceptual framework as marginal ELCC but employs a methodology that requires far fewer model runs. We consider these two options to be functionally synonymous.

[138] NYISO Market Monitoring Unit and Potomac Economics, NYISO Capacity Accreditation: Conceptual Framework and Design Principles, August 9, 2021, p. 19.

approach.[139] NYISO does not specify any particular design details in this filing, but it does state its intention to consider ELCC/MRI for all resource classes, including existing conventional resources.[140]

V. Potential Implications for Consumer Costs

The single largest cost driver for consumers would be if resource adequacy requirements and total reliability needs are not met. As a consequence, consumers would suffer the costs of energy shortages, while paying for capacity that did not deliver as-expected. Plus, they would likely have to pay for costly out-of-market Reliability Must Run (RMR) contracts or manual commitments that likely are not the lowest-cost (and have historically focused on fossil resources).

The other cost drivers are primarily focused on the accuracy of accounting and economic incentives. The most accurate measurements and efficient incentives will tend to reduce consumer costs by driving the most cost-effective reliability (via both the FCM itself and via bilateral and state contracts to the extent these internalize the accurate capacity value of resources).

Cost effective reliability could be achieved if all resources were awarded based on an accurate measure of their marginal contribution, if that is possible. Such an approach would further minimize customer costs by reducing the total amount of capacity to a level corresponding to the average load during shortage conditions (plus reserve margin for variability), which could be slightly less than current purchases based on peak load. This would avoid paying producers for the value they provide relative to a hypothetical system where (arbitrarily specified) classes of resources did not exist and customers had to pay for capacity to increase scarce supply during peak loads.

[139] NYISO filing letter *re* New York Independent System Operator, Inc., Excluding Certain Resources from the "Buyer-Side" Capacity Market Power Mitigation Measures, Adopting a Marginal Capacity Accreditation Market Design, and Enhancing Capacity Reference Point Price Translation in FERC Docket No. ER22-349-000, January 5, 2022.

[140] *Id.*, p. 34.

VI. Criteria for Assessing Resource Accreditation Options in New England

The upcoming NEPOOL and ISO-NE processes for assessing alternative resource accreditation options could be challenging because the results could significantly impact market participants' financial outcomes. Additionally, unlike in some other market design contexts, there is no perfect solution that will avoid reliance on administrative judgement and modeling uncertainties.

In evaluating options for resource accreditation, the guiding principles should be to: (1) help ensure that **reliability** will be maintained; (2) **provide a reliability-neutral exchange rate** among resources, both to enable reliable substitutions and to signal efficient investment—which requires accurately expressing each resource's marginal reliability value; (3) help **incent resource owners** to enhance, maintain, and operate their facilities to be able to perform when needed most, by reflecting demonstrated performance in their accreditation; and (4) **recognize modeling and data limitations** that may differ among types of resources.

Based on these principles, we identify seven relevant criteria for evaluating accreditation approaches and assessing tradeoffs, summarized in Table 2.

TABLE 2. PROPOSED CRITERIA FOR ASSESSING RESOURCE ACCREDITATION OPTIONS IN NEW ENGLAND

Criteria	Description
Reliability	• Will the reliability modeling accurately represent shortage risks when establishing resource adequacy requirements and associated resource accreditations, so as to ensure that the system maintains reliability? • Will the ISO, New England states, and consumers be confident that the total of accredited resources are sufficient to meet system resource adequacy needs, without backstop interventions?
Economic Efficiency	• Will the design incentivize an efficient investment level, resource mix, and level of demand resources? • Will the design incentivize operational decisions that minimize societal cost while supporting system reliability?
Technology-neutrality	• Will the design appropriately reward all resource types for their reliability contributions? • Will classes of resources be compensated for their full contribution to the reliability objective? • Will resources be fairly accredited for performance/capabilities exceeding their class average? • Will implementation timing ensure that no resources face inconsistent early application of ELCC, even while others are over-compensated due to implementation delays?
Performance	• Will individual resources be incentivized to maximize their performance during reliability events? • Will new resources/investments be incentivized to pursue upgrades or operational changes that result in improved going-forward performance?
Practicality	• What are the modeling and data requirements of each design? • What barriers to implementation may exist?
Transparency	• Is the design reasonably easy to understand? • To what extent might market participants be able to predict their resource accreditation? • Is the approach overly sensitive to administrative judgement, modeler choices, and administrative error?
Consumer Cost	• Will consumer costs be contained, considering both risk of out-of-market actions and accuracy of incentives, and accounting toward least-cost reliability?

We will apply these criteria in our forthcoming paper assessing a range of alternative approaches to resource accreditation in New England.

List of Acronyms

AESO	Alberta Electric System Operator
ARA	Annual Reconfiguration Auction
AGO	Attorney General's Office
CAISO	California Independent System Operator
CCP	Capacity Commitment Period
CPUC	California Public Utilities Commission
CSO	Capacity Supply Obligation
DC	Direct Current
DER	Distributed Energy Resource
DR	Demand Response
EFORd	Equivalent Forced Outage Rate Demand
ELCC	Effective Load Carrying Capability
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
GE-MARS	General Electric Multi-Area Reliability Simulation
GHG	Greenhouse Gas
GW	Gigawatt
HQ	Hydro-Québec
ICAP	Installed Capacity
ICR	Installed Capacity Requirement
ISO	Independent System Operator
ISO-NE	ISO New England or Independent System Operator of New England
ITC	Investment Tax Credit
IMM	Independent Market Monitor
LDC	Local Distribution Company
LOLE	Loss of Load Expectation
LRE	Load Responsible Entity
LSE	Load Serving Entity
LSR	Local Sourcing Requirement

MA AGO	Massachusetts Attorney General's Office
MARS	Multi-Area Reliability Simulation
MCL	Maximum Capacity Limit
MISO	Midcontinent Independent System Operator
MRI	Marginal Reliability Improvement
MW	Megawatt
MWh	Megawatt hour
NEG-ECP	Conference of New England Governor and Eastern Canadian Premiers
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NQC	Net Qualifying Capacity
NYISO	New York Independent System Operator
PJM	PJM Interconnection
POLL	Probability of Lost Load
PRISM	Probabilistic Reliability Index Study Model
RA	Resource Adequacy
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard
SERVM	Strategic Energy & Risk Valuation Model
SPP	Southwest Power Pool
UCAP	Unforced Capacity
XEFORd	Equivalent demand forced outage rate, excluding causes of outages that are outside management control
ZRC	Zonal Resource Credit

Authors

Samuel A. Newell leads Brattle's Electricity Group of over 50 consultants addressing the most challenging economic questions facing an industry transforming to clean energy. His 23 years of consulting expertise centers on electricity wholesale markets, market design, generation asset valuation, integrated resource planning, and transmission planning. He frequently provides testimony and expert reports to Regional Transmission Organizations (RTOs), the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and the American Arbitration Association. Dr. Newell earned a Ph.D. in Technology Management & Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science & Engineering from Stanford University, and a B.A. in Chemistry & Physics from Harvard College.

Sam.Newell@brattle.com

Kathleen Spees is a Principal at The Brattle Group with expertise in wholesale electricity and environmental policy design and analysis. Dr. Spees has worked in more than a dozen international jurisdictions supporting the design and enhancement of environmental policies and wholesale power markets. Dr. Spees earned her PhD in Engineering and Public Policy within the Carnegie Mellon Electricity Industry Center and her MS in Electrical and Computer Engineering from Carnegie Mellon University. She earned her BS in Physics and Mechanical Engineering from Iowa State University.

Kathleen.Spees@brattle.com

John Higham is a Senior Research Analyst with The Brattle Group, specializing in wholesale power market design. He holds a bachelor's degree in Mathematical Economics from Colorado College.

John.Higham@brattle.com