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Evolving Planning Criteria for a Sustainable Power Grid

A Workshop Report

July 2024

RELIABILITY | RESILIENCE | SECURITY

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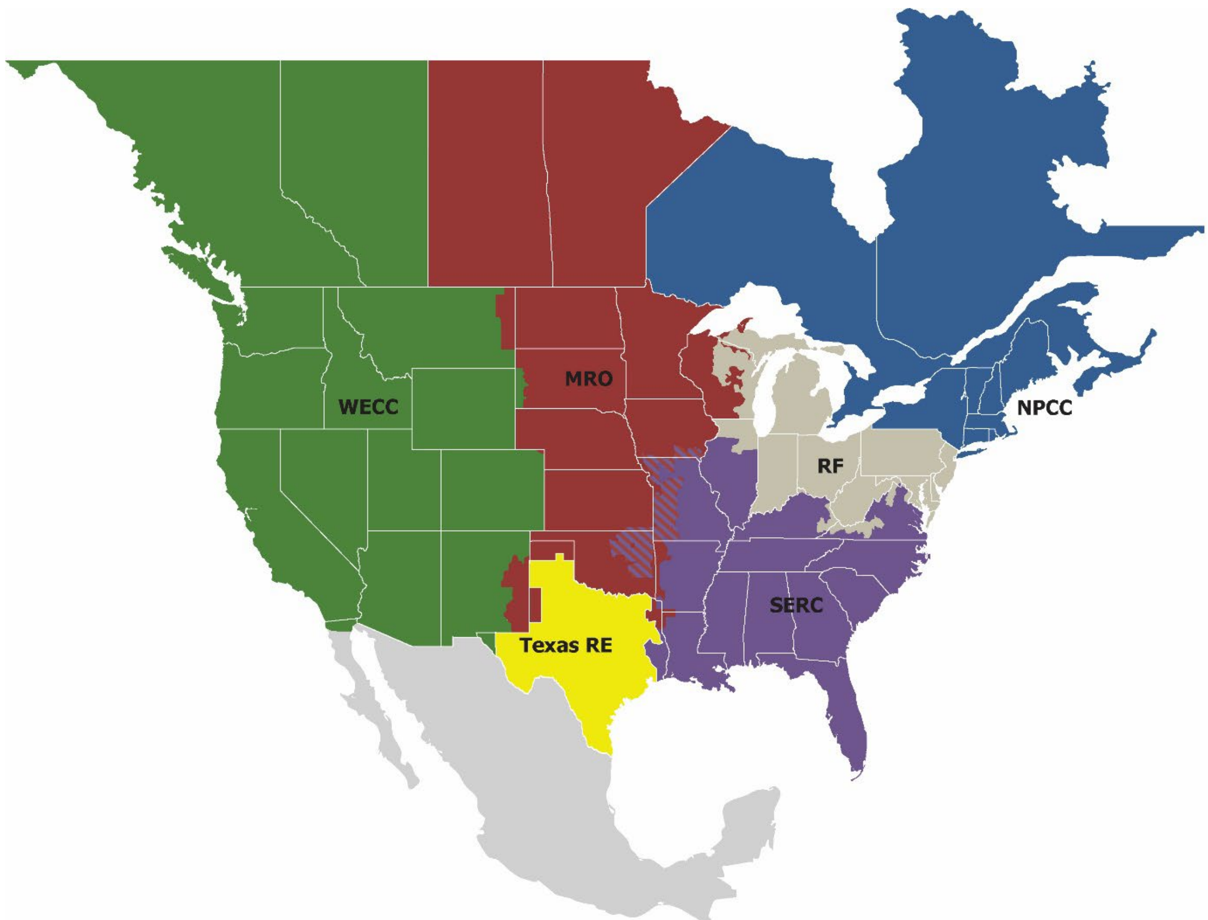
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to ensure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

This report summarizes the proceedings and actionable recommendations from the co-sponsored NERC and NAE Section 6 workshop in March 2024 that focused on examining electric reliability criteria for planning resource and transmission adequacy on the transforming grid. The workshop, "Evolving Planning Criteria for a Sustainable Power Grid," assembled industry thought leaders to build consensus around the need for additional criteria, actionable short- and long-term recommendations, and next steps. The workshop concentrated on two broad topics: capacity vs. energy and planning the evolving transmission grid.

The recommendations in this report complement the first workshop hosted by the NAE Section 6 in October 2022, the outcome of which resulted in the report *Creating the Sustainable National Electric Infrastructure While Maintaining the Reliability and Resiliency of the Grid*.[1]

Given that electricity plays an essential role in modern society, energy adequacy is a critical complementary consideration of resource adequacy to ensure overall system reliability. Traditional resource adequacy models and approaches are rooted in a loss of load expectation (LOLE) criterion of 1-day-in-10 years, which is focused on peak hour conditions. However, LOLE does not adequately account for the growing risk, over all hours, arising from increased variability and uncertainty caused by the evolving resource mix and increasing demand levels. A recent Energy Systems Integration Group (ESIG) survey of electric industry professionals, shown in **Figure E.1**,[2] asked whether industry should consider a new resource criterion. Data from the survey overwhelmingly indicated that industry should consider a new approach—beyond the LOLE criterion alone—to resource adequacy modeling that reflects the reliability needs of the rapidly evolving grid. Survey results indicated that there is not just one solution, and supplemental criteria are needed that consider the size, frequency, timing, and duration of energy shortfalls.

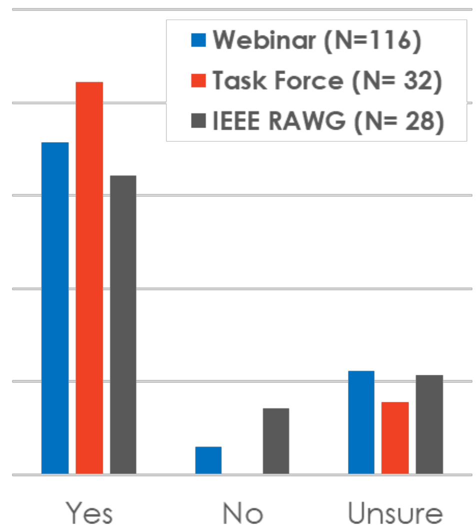


Figure E.1: ESIG Survey Question—Should Industry Consider a New Resource Adequacy Criterion?

Traditional resource adequacy models and approaches rooted in a LOLE of 1-day-in-10 years do not adequately account for the essential role that electricity plays in modern society…

The Regional Energy Shortfall Threshold (REST), the Independent System Operator New England (ISO-NE) initiative to move beyond LOLE, reflects the region's risk tolerance with respect to energy shortfalls during extreme weather. The ISO-NE energy adequacy studies, using the Probabilistic Energy Adequacy Tool (PEAT), are expected to play an important role in informing the ongoing development of REST. Using innovative approaches, such as REST and PEAT along with a consistent approach to performing assessments over a wide area,[3] could more effectively measure

[1] *Creating the Sustainable National Electric Infrastructure While Maintaining the Reliability and Resiliency of the Grid*, NAE – Section 6, October 24, 2022.

[2] New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements, ESIG, March 2024, Figure 1, p. 12 (Note: RAWG – IEEE Reliability Assessment Working Group).

[3] A wide-area approach extends beyond the planning assessment area under study to the ability of neighboring systems to provide transfers at times of calculated shortfalls.

energy adequacy. This is particularly relevant in extreme weather where impacted areas are highly reliant on long-distance transfers from other areas that have greater fuel diversity and sufficient resources to serve demand and meet their reserve margins. Planners outside of North American that are experiencing similar resource adequacy challenges have implemented varying approaches. For example, seven countries in Europe have adopted an LOLH criterion of less than or equal to three hours per year to account for energy and resource adequacy risks. The Australian National Energy Market (NEM) Reliability Panel sets a normalized EUE (NEUE) of less than or equal to 0.002% per year.[4]

NERC's most recent evaluation of the EUE metric in its *2023 Long-Term Reliability Assessment* (LTRA)[5] demonstrates that using EUE identifies risk not captured using other metrics, such as reserve margins. Therefore, from an assessment perspective, additional metrics for evaluation can inform risk assessments and call attention to where risk might be unacceptable. NERC is now using a set of thresholds for future LTRAs that align with the EUE and LOLH metrics. These thresholds do not establish resource adequacy criteria; rather, they offer an approach to consistently apply energy evaluations across all assessment areas in North America. Since EUE represents the amount of total energy unserved, it can be normalized over an assessment area and interconnection.

NERC Actions Resulting from the Workshop

NERC's LTRA quantifies the normalized expected unserved energy (NEUE) metric as the ratio of energy unserved relative to total annual energy. A NEUE of zero is considered low risk, less than or equal to 0.002% is medium, and any NEUE greater than 0.002% is high. These represent reasonable thresholds that would cover the losses in the most recent cold weather events referenced in **Table 2.1.** Further, a threshold of 0.002% is consistent with several countries, including that of the Australian Energy Market Operator (AEMO), which has significant renewable resources in several states and has experienced challenges with resource adequacy. This is a starting point that sets the stage for further refinement. Tailored criteria in terms of EUE and LOLH for each area will be developed and supplement a 1-day-in-10 reliability expectation.

In addition to using more robust metrics and criteria, a broader set of design-based scenarios must be developed to provide analyses that are technically sound and provide more insight. Adequate system performance should be ensured within a spectrum bound by defined parameters such as the outer ends of the distributions of input data, sometimes referred to as the tails. While the tail events encompassed in these scenarios are usually averaged into an overall index, planners may want to ensure that certain tail events are fully understood and mitigated by this scenario analysis. These tail events are generally associated with extreme-condition impacts, such as a low-temperature and no-wind scenario or a 99th percentile demand coupled with a pipeline outage.

Input from the workshop resulted in nine actionable topic areas that, combined, form an improved approach to resource adequacy. These topic areas are the basis for the recommendations detailed in **Chapter 4** and are summarized in **Table E.1**. The following are the actionable topic areas:

- Accomplish a consistent approach to resource adequacy planning by using a multi-metric approach supplementing LOLE with EUE and LOLH
- Address duration and magnitude of load loss by incorporating EUE and summaries of individual event characteristics
- Coordinate generation and transmission adequacy studies to the greatest possible extent
- Assure that chronological studies for transmission planning are conducted

[4] *Resource Adequacy for a Decarbonized Future: A Summary of Existing and Proposed Resource Adequacy Metrics*, EPRI, April 2022, Table 2, p. 8.
[5] *2023 Long-Term Reliability Assessment*, December 2023.

- Include stressed scenarios in the resource and transmission planning process
- Determine transmission energy adequacy for stressed resource adequacy scenarios
- Ensure a more comprehensive approach to load forecasting by planners
- Standardize the use of Monte Carlo simulations as a tool for resource and transmission adequacy planning
- Continue enhancing NERC's annual 10-year resource adequacy assessment, the LTRA, with enhanced energy metrics that more accurately measure the energy frequency, event duration, and event magnitude reliability risks

The long-term recommendations listed in **Table E.1** further expand on these nine topic areas. They include continuing the evolution of the resource adequacy criterion, collecting quality data, building composite plans across the interconnections, tracking demand increases resulting from electrification, developing extreme scenarios, finding ways to increase transfer capacity, improving coordination of transmission with distribution, and improving benchmarking metrics to enhance the energy adequacy assessment process.

Next steps include augmenting NERC's LTRA to include a "Reliability Threshold" that uses a non-binding measure for assessing system energy adequacy based on these metrics and a set of scenarios, enabling NERC to better assess energy adequacy and drive industry toward a specific target or set of targets—recognizing that a one-size-fits-all approach may not work given the diversity of resources, load, and transmission topologies. Assessing energy adequacy with the addition of an energy-centric EUE will measure the magnitude of demand exceeding the available capacity across all hours. **Table E.1** summarizes the recommendations.

Table E.1: Actionable Takeaways	
Near-Term Recommendations	**Longer-Term Recommendations**
<u>1-day-in-10 LOLE evolution:</u> NERC should lead the development of a multi-metric approach augmenting LOLE with LOLH and EUE	**<u>1-day-in-10 LOLE evolution:</u>** NERC should further work to develop additional criteria beyond LOLH and EUE
Duration and magnitude of load loss: NERC should lead industry to incorporate LOLH and EUE to address unserved energy duration and magnitude and report event-based statistics	**Quality data:** NERC should determine data collection needed to inform planning (e.g., battery charge/discharge behavior, climate data, and [correlated] forced outage rates)
Coordinated, composite approach to reliability study: NERC should effectuate consistent evaluation of LOLH and EUE over the various interconnections such that market administrators and system planners can ensure sufficient resources and transmission through regulation or standards	**Composite system reliability programs:** NERC should facilitate the transition of research work in academia and the Institute of Electrical and Electronics Engineers (IEEE) into BPS planning practice
Chronological studies: NERC should pilot a chronological study of the hourly profiles needed to capture inter-hour relationships that could be constraining, such as ramping and storage scheduling	**Demand changes:** NERC should monitor load changes, including those due to electrification, that may lead to shifts in the peak conditions; consider developing technical paper(s) about how to best integrate flexible resources
Stressed conditions: NERC should continue developing standards requiring the planning to consider extreme and stressed conditions and associated sensitivities	**Scenarios:** NERC should continue to create standardized or common guidelines for consistent and actionable planning scenario development

Table E.1: Actionable Takeaways	
Near-Term Recommendations	**Longer-Term Recommendations**
Determine transmission energy requirements: NERC should facilitate collaboration to improve grid robustness by having resource adequacy planning inform transmission planning	**Transfer capability:** NERC should identify opportunities to increase energy transfers over greater distances between assessment areas to reduce constraints
Comprehensive load forecasts and transmission and distribution (T&D) planning: Industry transmission planner forecasts must account for distribution system resources and electrification impacts, extreme weather stressed scenarios, and gathering data beyond the operations planning horizon	**Transparency:** NERC should promote higher levels of T&D coordination in planning and operations and help industry improve data intelligence beyond the standard 10-year planning horizon
Simulations: NERC should lead industry toward using Monte Carlo simulations to calculate broad risks and deterministic simulations (i.e., scenarios) to identify specific low-probability tail risks	**Tool and Method Advancement:** NERC should continue leading industry to advance the tools and methods for performing energy adequacy analyses and probabilistic simulations (e.g., ISO-NE's PEAT and REST)
Measuring: NERC must augment its LTRA with enhanced energy metrics that more accurately measure the energy frequency, event duration, and event magnitude reliability risks	**Benchmarking:** NERC should continue monitoring metrics and advance criterion enhancements to adapt with the evolving grid

Chapter 1: The Energy Adequacy Planning Problem

Problem Statement

Due to the resource mix transformation, existing criteria used to determine adequate levels of capacity, energy, and transmission insufficiently represent reliability risk. In their application, current adequacy criteria fail to differentiate between the scenarios, size, frequency, duration, and timing of energy shortfalls. This has become increasingly important as the resource transformation evolves from capacity-based resources without fuel limitations to energy-constrained resources that are increasingly impacted by weather and environmental conditions. Therefore, supplemental criteria must be adapted to properly assess system adequacy and help determine appropriate solutions.

The workshop was divided into two major topic areas: **Energy Assurance (Capacity Versus Energy: Changes in the Way to Plan for Resource Adequacy**) and Transmission Planning (**Planning the Evolving Transmission Grid**). These are detailed below.

Capacity Versus Energy: Changes in the Way to Plan for Resource Adequacy

Industry's methods of planning for resource adequacy need to change. The modern power system requires the enhancement of assumptions and supplementation of risk information for a better characterization of the risk. Historically, the resource adequacy criterion has been based on the LOLE metric, which should be no more than 1 event-day in 10 years when the generating resources are less than load (commonly known as "1-day-in-10"). This has been a design basis for the U.S. electric grid for at least 70 years (with its first formal mention in a 1951 American Institute of Electrical Engineers paper by C. W. Watchorn) and has historically served the industry well. Two important related but separate discussion topics include considerations for assumptions in the calculation of LOLE and other metrics and the establishment of the resource adequacy criteria (i.e., traditionally in terms of LOLE-1-day-in-10).

The 1-day-in-10 LOLE criterion is commonly converted into a minimum capacity requirement resulting in a target or Reference Margin Level (RML). In doing this, planners determine the minimum Planning Reserve Margin (PRM) required to maintain a 1-day-in-10 LOLE level. Historically, systems with an actual PRM above the minimum generally have sufficient resources and provide adequate energy and essential reliability services[6] that operators need to reliably operate the BPS.

Issues can arise in resource adequacy planning processes when planners solely rely on the RML comparison as the system transforms from an era of certain to more uncertain fuel sources and load demand response. In recent years, NERC has documented warnings of potential energy shortages in its reliability assessments in cases where the reference reserve margin comparison indicates no shortfall. Substantial uncertainty has been introduced into planning the system with the addition of energy-constrained resources (inverter-based resources such as wind and solar, and, at times, other fuels such as natural gas) that are highly dependent on weather and environmental conditions. Uncertainty in energy sufficiency is increasing as resources once certain in their ability to be dispatched (dispatchable resources) in response to the variable resource availability are constrained by fuel supply, reservoir depletion, or battery discharge. Historical generator reliability assumptions based on the idea of well-maintained, well-invested units with an anticipated long life are no longer adequate. This increases uncertainty as a greater proportion of fossil-fueled resources continue to be retired with or without notice to the planners. Nameplate values of variable energy resources are not as meaningful as projected energy availability, and environmental conditions can adversely impact the simultaneous availability of thousands of megawatts.

[6] *NERC Essential Reliability Services Whitepaper on Sufficiency Guidelines*, December 2026.

Assumption Considerations: LOLE was introduced in an era in which the grid was dominated by large fossil, nuclear, and hydro generation that had long-term and known fuel availability as well as less complex loads and more predictable demand. Historically, LOLE was calculated by evaluating only peak load days and has been modified over time to consider all days and hours. In addition, this metric was based on generating nameplate capacity and derated according to the unit type or failure mode representation; this required making several significant assumptions that were justified at the time. While the application of LOLE in planning studies has relevance, the aforementioned assumptions are increasingly unreliable, especially with the rapid growth in wind and solar generation whose fuel availabilities are far less certain. LOLE calculations are also based on many other assumptions that are becoming increasingly tenuous and may not fully represent the dimensions of risk that are most important to industry leaders and policymakers. These assumptions include the following:

- Unit outages during a few peak conditions, such as the summer peak, contribute the most to the LOLE.
- Each day is independent and does not include forced outages of generators from the day before as units would come back on-line or other actions could be taken to balance generation and load.
- Generator failures are random and independent from each other with no correlations due to common conditions or failure modes.
- Fuel is readily available 24/7.
- Daily peak demand is the most resource-constrained period of the day.
- Transmission system is a “copper sheet” (i.e., no constraints, no congestion).
- Sufficient amounts of energy and essential reliability services (e.g., ramping, voltage, and frequency) are available with a basis in capacity.

Over time, planners have fully or partially addressed these assumptions to improve LOLE calculation accuracy. While this report recommends the addition of two metrics to supplement LOLE, efforts to improve model fidelity and confirm input assumptions and methods should continue. These improvements can yield insights from LOLE calculations and calculations of other metrics. Although resolving these assumption challenges will require additional work, this does not mean that LOLE is inherently problematic. On its own, LOLE has proved an effective metric in the past to justify the construction of generation and other investments.

Establishment of the Resource Adequacy Criteria: Resource adequacy criteria attempt to generally balance the economic value of reliability with the cost of supplying a predetermined specific level of sufficiency. Recent research is insufficient to determine the exact economic benefits of using the current 1-day-in-10 resource adequacy criterion. Additionally, it is unclear if this longstanding criterion still offers the best balance between reliability and cost. Given the reliance on electricity, this raises the question of whether the 1-day-in-10 criterion might be too low (or too high) for today’s resource adequacy needs.

Today’s application of the 1-day-in-10 criterion does not generally define the duration nor magnitude of the shortfall as measured by the LOLH and EUE metrics, respectively. EUE for a power system is the energy a system was unable to serve due to capacity shortages likely caused by a combination of events such as generator outages, severe weather, or higher-than-expected demand. While there is a clear need for applying a multi-metric approach in addition to the 1-day-in-10 criterion, there is less consensus that the 1-day-in-10 years resource adequacy criterion needs to be changed.

The changes in the power system—increases in new types of generation resources, storage, inverter-based resources connected at lower voltages (including consumer owned), and other resources that could include vehicle-to-grid delivery—have complicated the use of traditional criteria, metrics, methods, and tools for calculating resource adequacy. Moreover, the newness of the technologies has made it difficult to gather enough operational data to characterize their probabilistic behavior needed for such calculations (e.g., correlation between generation from various renewable resources and load). Lastly, after the restructuring of the generation market in some parts of the United States, there is no consistent analytical method for assuring resource and energy adequacy across multiple assessment areas within an interconnection, creating uncertainty regarding the assumptions that one area could rely on another area during stressed system conditions. This problem is expanded upon in the next section.

Planning the Evolving Transmission Grid

A strong and flexible electric transmission system capable of coping with a wide variety of system conditions is necessary for a reliable supply and delivery of electricity. Electric power transfers can significantly affect the reliability of interconnected electric transmission systems. Recent and continuing resource mix evolution requires greater access and deliverability of resources to maintain reliability—particularly during extreme weather and environmental conditions.

Planning for future electricity needs involves two key steps:

- **Determining how much electricity will be needed (demand) and how it will be generated (generation fleet):** This considers uncertainties like future economic growth and environmental regulations. The goal is to find the most cost-effective way to generate enough electricity reliably while potentially meeting other goals like using more renewable energy.
- **Evaluating the impact of building new transmission lines:** Once the expected electricity needs and generation plan are known, new transmission lines can be assessed to understand how they would address the needs of the system. Scenario studies with and without the new lines are needed to understand how they influence electricity prices and system stability.

Transmission planners currently analyze the connections between transmission planning areas to determine the maximum level of transmission transfer capability as well as scenarios that might limit the capability. This capability is used to address resource shortfalls and enable firm or economic transfers and emergency purchases. Because there is no specific industry-accepted standard for setting resource adequacy criteria or protocols for determining the amount of transfer capability, there is considerable variation across the continent.

Electric power transfers can significantly affect the reliability of the interconnected electric transmission systems.

The probabilistic planning process used in resource adequacy analysis can also be expanded to traditional deterministic transmission planning. Power grid reliability is currently assessed using a fixed-scenario approach to determine whether system performance meets NERC Transmission Planning (TPL) standards. If not, TPL requires the implementation of corrective action plans to meet the performance-based scenarios to ensure an acceptable level of system steady-state and dynamic performance.

Deterministic scenarios were not developed for probabilistic planning and have limitations because they do the following:

- **Focus on worst-case scenarios:** They analyze how the grid performs under peak demand and specific equipment failures (contingency sets: outage of a single generator, transmission line, or combination of facilities).
- **Ignore probabilities and variability:** They do not consider the likelihood of these failures or how changes in demand (like bad weather) might affect reliability.
- **Do not compare options easily:** It is hard to tell which upgrades provide the most benefit if several options solve the same worst-case problem.

Probabilistic analysis enhances deterministic transmission planning from an energy adequacy standpoint given the following factors:

- **Considers likelihood of events:** It uses historical data to estimate how often different outages and weather conditions might occur.
- **Provides more information:** It calculates the average impact of these events, including how often and how long power outages might last.
- **Helps compare options:** It enables the selection of the upgrade(s) that provide the best balance between cost and reliability over time to be chosen.

Probabilistic analysis more effectively assesses energy adequacy for reliability because it considers the risk of extreme events, not just the average case. This is important because occurrences like bad weather or unexpected outages can much more significantly impact reliability than good weather or periods without outages.

Data from operations is needed for energy metrics to sufficiently assess resource adequacy, and there needs to be additional information beyond the operations horizon (less than 1 year), and the near-term (1–5 years) and long-term (5–10 years) transmission planning horizons. This not only supports BPS reliability but also the increasingly impactful distribution systems. Furthermore, as T&D interrelationships continue to evolve between the supply segment and the delivery grids, it is becoming increasingly important to plan these systems in a coordinated fashion by considering the full, integrated effect of all generation resources and loads. This framework includes comprehensive load forecasts and more integrated T&D planning, discussed in greater detail in **Chapter 2**.

Chapter 2: Breakout Session Outcomes

Workshop participants heard from nine presenters who offered perspectives with common themes and consistent messages focused on the need to enhance the present resource adequacy planning around capacity, energy needs, and transmission planning. These presentations set the groundwork and served as a primer to begin focusing on the need for change in each of the four breakout sessions.

One leading message in both the presentations and breakout sessions was that the current use of the 1-day-in-10 years LOLE criterion is an incomplete measure to capture today's risks, resulting in insufficient energy to meet demand for all hours. Figure 2.1 shows how an annual LOLE can mask the frequency, duration, and magnitude of events.

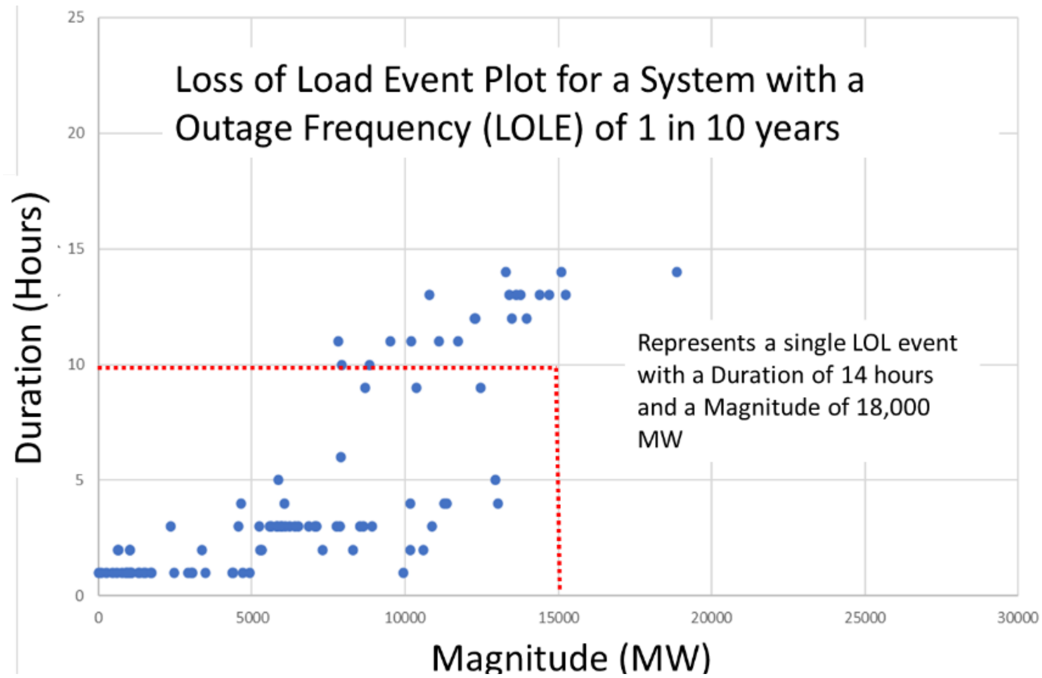


Figure 2.1: ERCOT Example of How LOLE Falls Short When Energy Is Not Considered

The blue dots in Figure 2.1 represent the unserved energy for the largest duration and magnitude observed in each of the Monte Carlo draw events. The Electric Reliability Council of Texas (ERCOT) uses Monte Carlo draws and probabilistic analysis to establish the resource mix necessary to meet a three-part reliability standard being developed for the Public Utility Commission (PUC) of Texas. This new potential standard could be based on the frequency, magnitude, and duration for a loss-of-load event in Texas.

LOLE (1-Day-in-10)

Most North American resource planners have historically used the LOLE criterion of 1-day-in-10 with some modifications depending on applications. LOLE does not have the ability to capture resource adequacy risk due to the transforming resource mix, thus leading industry leaders to consider ways to supplement the use by adding a multi-metric approach. The LOLE criterion measures the number of days of load loss on average, whereas the LOLH criterion measures the number of hours of load loss but does not account for the amount of load loss or differentiate between smaller but more frequent and larger and less frequent load-loss events. Figure 2.2 shows the number of hours with system operator-initiated firm load shed from 2018 to 2022, which highlights the variation in the depth of load loss each year.

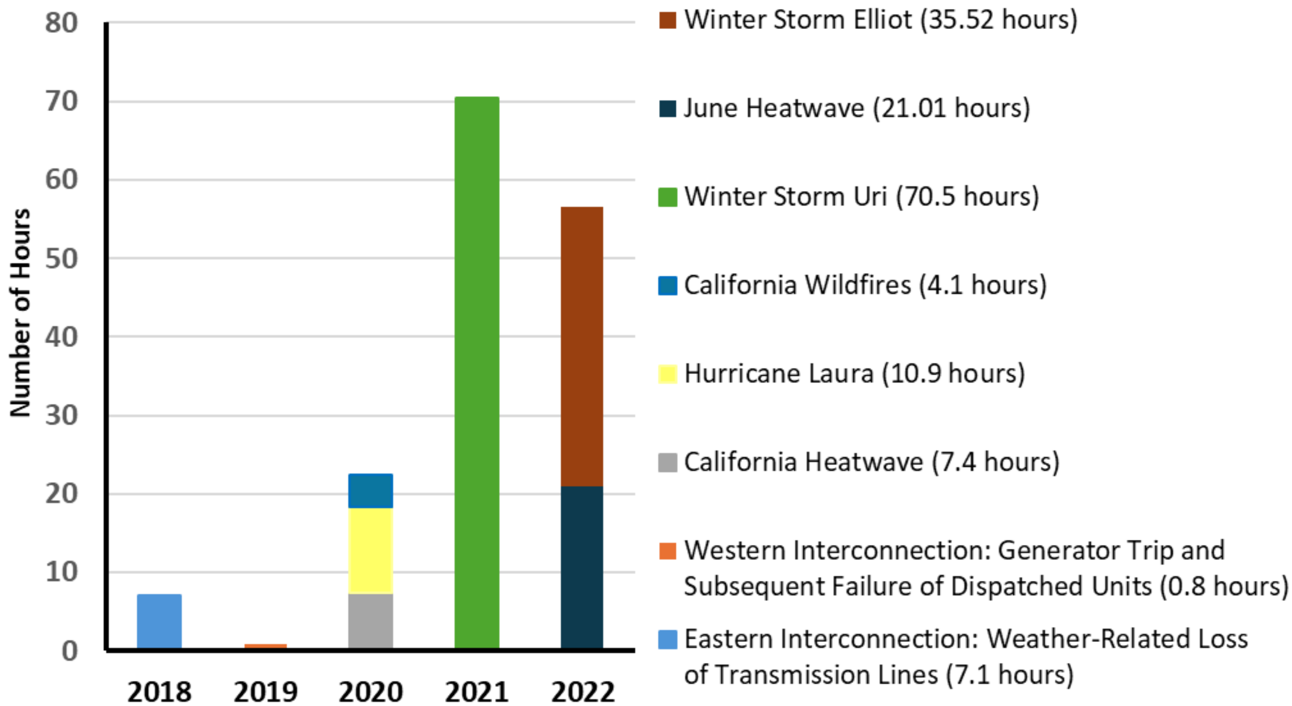


Figure 2.2: Hours with Operator-Initiated Firm Load Shed

In addition to accounting for the number of hours using LOLH, augmenting LOLE with EUE can inform resource planners of the total amount (magnitude) of load loss, but this augmentation provides no indication of frequency and duration. In contrast to the use of LOLE in North America for assuring energy adequacy, Europe tends to use LOLH, and other parts of the world tend to use EUE and other criteria.[7] More resource planners are beginning to incorporate EUE as well as other criteria beyond LOLE alone, so a multi-metric approach is needed.

Duration and Magnitude of Load Loss

Establishing a design basis for all resource adequacy planners to use will create the needed consistency to ensure reliability and transparency for consumers and policymakers. The LOLE criterion has been useful historically to ensure a high level of reliability in a capacity-certain world; however, resource adequacy must address other unserved energy possibilities in the evolving grid.

Designing the BPS to account for both frequency and duration (with reliability and cost in mind) can be accomplished through an understanding of the shortfall magnitude. LOLE can be interpreted as a frequency, but frequency and duration are separate indices. This interpretation can exacerbate confusion among planners that use LOLE, which, again, is an average and cannot fully account for the frequency and duration indices. Together, LOLH and EUE probability-based indices are suitable for and require less data than the frequency and duration indices. A single approach may not strike a balance between energy adequacy (i.e., reliability) and cost. There is an ability to normalize EUE to regional (i.e., localized vs. wide area) differences to balance these perspectives for electric systems of varying size. **Table 2.1** provides an example of duration (hours), magnitude (size in MW), and the resulting EUE metric for extreme weather events.

[7] Resource Adequacy for a Decarbonized Future: A Summary of Existing and Proposed Resource Adequacy Metrics, EPRI, April 2022, Table 2, p. 8.

Table 2.1: Extreme Weather Events Disrupt Electricity Supplies at Unacceptable Levels					
Event	**Area**	**Duration (Hours)[8]**	**Firm Load Shed (MW)[11]**	**Unserved Energy (MWh)[9]**	**Unserved Energy (Percent Annual)[10]**
2020 Heat Dome	California-Mexico (CAMX)	8	1,879	7,772	0.0030
2021 Winter Storm Uri	ERCOT	105	20,000	1,002,375	0.2366
	SPP	9	3,443	12,010	0.0045
2022 Winter Storm Elliott	SERC Central	18	4,820	70,182	0.0311
	SERC East	10	1,961	19,225	0.0086

Variable thresholds for metrics like EUE and LOLH could work for North America as they are used in Australia and Europe, but these thresholds must be coordinated with policymakers because the use of variable or different thresholds between neighboring systems could lead to unidentified risks. For example, consideration must be given if organization "A" plans to accept loss of load for 10 hours and 1,000 MWs and neighboring organization "B" is at 5 hours and 500 MWs, as the potential for loss of load impacting "B" by "A" might result in lower overall reliability if the transfer assumptions are not accurately represented.

Composite Generation and Transmission Planning

Resource and transmission planners must study the BPS in a coordinated fashion to the extent possible. In many assessment areas, coordination is conducted via wholesale market structures, such as capacity markets that serve to clear/procure the required resources to meet a defined reliability criterion. Generally, in restructured markets, long-range coordination of transmission and generation cannot be conducted because the generation to be built is speculative in the long term (since there is no central resource planner). Thus, the transmission planner is typically reactive to the market. The Federal Energy Regulatory Commission (FERC) final rule on transmission planning will require transmission planners to coordinate with states to plan sufficient transmission to meet policy goals and integrate and deliver clean energy.[11] Probabilistic tools and methods must be consistent, and this should be specified through appropriate regulations/standards that set the required coordination between planning areas to ensure that sufficient transmission is built in the most likely locations of potential resources to meet load. For example, planners must understand differences in the operations and planning horizons and regional and seasonal differences, including the need for the right data. In restructured assessment areas, this may require scenario-based transmission planning since it is not possible to accurately predict the emerging resource mix. In vertically integrated planning areas, central planners can plan the transmission system with greater certainty because the resource mix is centrally planned.

When regional storms impact the T&D systems, industry has "mutual assistance" programs to support restoration with crews and equipment. Likewise, when future storms and extreme weather events remove substantial amounts of resources, mutual assistance will be needed in the form of transfers from outside the regionally impacted area.

[8] Duration and firm load shed values come from EEA-3 Event Reports.

[9] Unserved energy is estimated using calculations from EEA-3 Event Reports or other reporting such as the NERC *State of Reliability* report.

[10] A resource adequacy metric used in some electricity systems is normalized unserved energy. For example, resource planners must maintain normalized unserved energy at or below 0.002% in parts of Australia.

[11] Order No. 1920, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, 187 FERC ¶ 61,068 (2024).

Adding more resources in the deficit area will not fully support shortfalls as neighboring areas could experience the same regional weather conditions simultaneously. This increases the importance of transmission as a way to manage the risk from the uncertainty presented by the transforming resource mix, where outages are correlated to environmental conditions and common mode failures.

Recent operational events on the BPS show that the energy needed to continuously meet customer demand, particularly during extreme conditions, is achieved through support from neighbors. Therefore, in addition to composite generation and transmission planning, assessing sufficient energy transfer capability of the transmission system presents an important opportunity to inform future planning. NERC's work performing the U.S. congressionally mandated Interregional Transfer Capability Study[12] (ITCS) will continue to assess transmission capability and adequacy periodically within its LTRA. Continual assessment of future energy deficits—based on an industry-vetted approach—using energy-based metrics and scenario analyses will lead to clear needs of both generation and transmission to support reliability criteria.

Established transmission planner processes do not apply enough emphasis on managing the uncertainty of energy-constrained resources, including associated fuel supplies. When new resources are built (e.g., offshore wind), they may be constrained when transferring energy to a particular interconnection point. Likewise, when new loads (e.g., data centers) are added to an area, they might be orders of magnitude larger than the existing load profile and therefore not have sufficient energy available to operate.

These mismatched loads and resources mean that resource and transmission planners require more substantive coordination, especially between the energy balancing authority and the transmission operator. Other owners, operators, and users of the BPS with significant roles are the coordinators who work with multiple resource and transmission planners. A centralized approach to informing the transmission planning process should be considered for consistency and oversight. While NERC conducts assessments and studies independent of industry and specific to reliability, NERC cannot conduct transmission planning or coordinate between generation and transmission because it lacks the jurisdiction, resources, and necessary tools.

ISOs/RTOs are resource neutral, meaning that they are prohibited from specifying the resource portfolio composition and directly coordinating generation with transmission. While ISOs/RTOs can address reliability issues, it remains difficult to address major congestion areas within markets. Difficulties in expanding transmission to alleviate congestion stem from public policy barriers in that states generally have different positions on cost and their agreement is required for interstate expansion. Barriers include cost-allocation battles of recent years that have resulted in an approach to transmission planning that just barely covers the requirements. When cost/benefit analysis must be narrowly calculated and allocated, there is no extra system margin created and the facilities added are "used up" as soon as they go into service.

In these areas, there are opportunities to increase transparency about transmission costs and provide ways for generation developers to better understand where the interconnection cost is not prohibitive or uncompetitive through the regulatory process. This could have a twofold benefit for ISO/RTO areas: First, it would likely reduce the queue for interconnection studies to eliminate the projects that would probably not materialize. Second, it becomes a substitute for being unable to coordinate directly between the generator and transmission planner but would yield greater visibility on where and what type of resources will be interconnected. In turn, this transparency could result in adequacy studies that would be more representative of future conditions in an already complex environment and facilitate more consistency with any established adequacy threshold or target.

Determining energy adequacy needs and achieving agreed-upon metrics/criteria can establish an adequate resource mix along with sufficient transmission infrastructure. Coordination should be iterative and transparent between the resource and transmission planners to the extent possible in meeting any metrics/criteria. Resource and transmission

[12] Fiscal Responsibility Act of 2023.

planners must expand their discussions with their generators, fuel suppliers, and electric distribution system entities when creating an iterative process toward transmission planning and resource adequacy.

Furthermore, a deeper understanding of the scenarios measured with progressive resource adequacy metrics is necessary to identify and craft the design basis due to changing climate and weather conditions, resource portfolio implications, and contingency selection. As with other discussions herein, collaboration must occur to increase resource and transmission planners' knowledge of the forces that impact a wide area such that credible planning scenarios are developed, employed, and validated. Validation will ensure that the scenario (anticipated possibility) for the system will meet the expected reliability thresholds or targets. Scenarios in this case are not simply creating cases for high demand, no wind, extreme weather, and so on; they must consider the bigger picture of load growth 20 or 30 years into the future along with the congestion that the transmission system could experience and the potential location of resources.

Hourly Chronological Studies

The vast majority of resource adequacy studies are performed on an hourly basis which leads to the need for transmission studies at a more granular level rather than a few daily peak hours. As observed with the transforming resource mix, the peak condition is not always when the worst condition(s) might occur. Now that resource availability is becoming more variable (uncertain) and electricity demand is growing, chronological studies are needed to ensure energy adequacy for all hours. Chronological studies will most likely need to involve inter- or intra-hour relationships (for all 8,760 hours/year), such as ramping and energy scheduling. Resource planners can address this added complexity by employing production-cost-based models with periodicities of day, week, month, and year. Planning in the operations horizon typically evaluates anticipated conditions on an hourly basis or using multiple intervals over a day. Long-term planning in the sense of determining resource needs is conducted on an annual basis (e.g., Years 1–3, 5, and 10) and needs to go beyond the typical 10-year horizon. Hourly study is required for the resource planner to implement a multi-metric approach for loss of load that includes duration and magnitude for these complexities given the resource uncertainty and factors like extreme climate events. This leads to consistency in the methods used to calculate the criteria, which is an additional burden on the planners. However, as a benefit, the additional study can reveal potential loss-of-load events during different hours of the day and in different months and loading characteristics not associated with peak hours.

A benefit to conducting chronological studies is gaining a better understanding of how to make the best use of energy storage systems for energy delivery. For example, battery energy storage systems become depleted during energy shortfalls if certain weather conditions persist and cannot be identified in peak-based studies. Studies can also reveal that there may not be sufficient time or capacity to recharge battery systems. Battery discharging and charging is illustrated in **Figure 2.3**, which shows the complex interplay with solar resources in the California Independent System Operator (CAISO) system for June 25, 2023. The figure shows that CAISO served 88% of its energy with wind and solar for a short period.

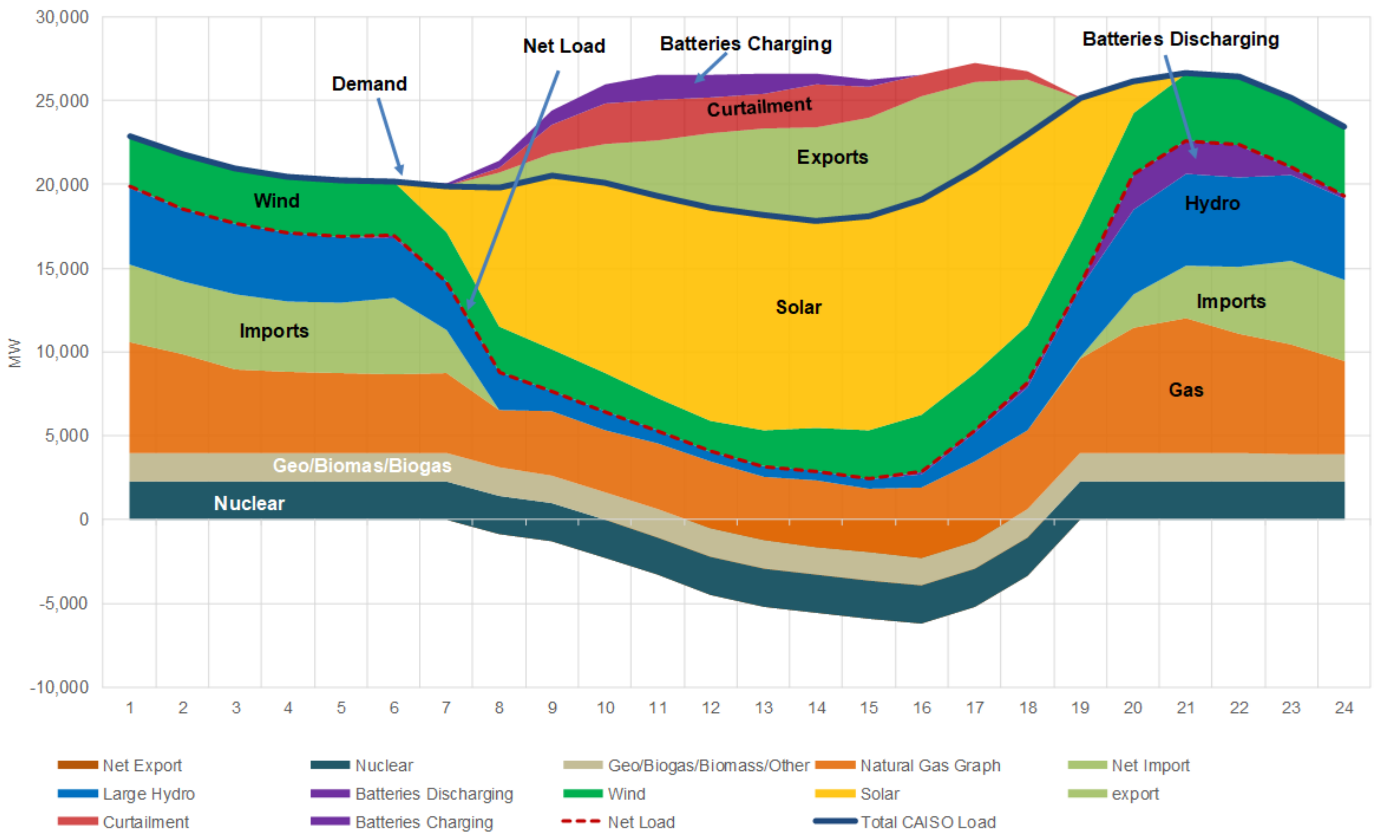


Figure 2.3: CAISO Graph Showing Complex Interplay Between Solar and Energy Storage

Another key theme around resource planning was how to determine the most effective way(s) to integrate energy storage and other flexible resources and flexible demand into studies. Overall, there needs to be a wider understanding of studying flexible resources in planning processes, which could include NERC developing a study, white paper, or reliability guideline. It was clear that chronological studies are more burdensome but probably also necessary to gain the needed visibility of flexible resources.

Stressed Scenarios

Transmission planning must be enhanced to incorporate more scenario-based planning. For example, planning scenarios used to stress the system must include various climate change impacts. Other complexities include reliance on transfers (i.e., imports), storage, interconnectedness with other energy sectors (e.g., natural gas), effects of distributed energy resources (DER) within the electric distribution system, and the potential for cyber and physical attacks and disruptions.

It is unclear how to craft appropriately stressed scenarios to reflect weather resulting from climate change and how to incorporate them into the probabilistic transmission planning process. The scenarios must consider probable extreme conditions that can occur coincident with other stressors affecting the performance of resource and transmission facilities, including the lack of sun and wind on a high-demand day or a cyber event affecting transmission visibility or disrupting generation output and control. Table 2.2 shows the method used by Tri-State Generation and Transmission to address resource adequacy for extreme events. It includes stressed transmission availability, power and gas pricing, market availability (depth and timing), continuous (fuel-certain) resources, intermittent (fuel-uncertain) resources, and load (based on historical events). Intermittent resources are additionally stressed for 72 hours over the peak period.

Table 2.2: Tri-State G&T Resource Adequacy Method		
Modeling	**Metric**	**Results**
• "Extreme Weather Event" (worst winter and summer week) • Assume no wind (winter and summer peak) • Assume no solar (winter peak) • Assume no imports from neighbors	• ≤ 12 LOLH during study period (10 years) • ≤ 3 LOLH in any one year • EUE ≤ 20% of total load in any one hour • Cannot rely on market purchases to meet load during critical peak	• Gas/oil plant is required for reliability, 30.5% PRM • Endorsed by Colorado PUC and 28 stakeholders in Tri-State Electric Resource Plan • Ongoing work with Rocky Mountain Institute to enhance method

Stressed scenarios must be analyzed thoroughly, which requires improved probabilistic modeling and scenario selection. Technologies like battery energy storage systems and multiple climate-spawned weather conditions add complexity to scenario planning, stressing the scenario further. Stressed scenario planning makes it difficult to benchmark events (e.g., cold/hot day, high demand, no wind, lower solar irradiance) while ensuring that the events are plausible and not overly restrictive, including prolonged or sustained occurrences. In any case, scenarios to be evaluated should be consistent with regional differences in weather conditions and design philosophies.[13]

An initial step is to establish a common starting point for scenario benchmark event development. For example, deterministic simulation for the stressed scenarios selected must be consistent, well-coordinated, and agreed upon between planners and neighbors. This also includes the periodicity of such plans and potentially extending the planning time horizons beyond 10 years, the minimum required period for long-term planning under the NERC transmission planning Reliability Standard TPL-001. Benchmark event development must be standardized with a set of common guidelines for consistent and actionable stressed scenario development.

Best practices emphasize the importance of incorporating climate impacts into scenarios when planning for large loads and energy storage. Nonetheless, extreme heat and cold scenarios (for example) could drive stressors in the study (e.g., a significant increase in peak load, transmission and generation outages; facility derating) to reveal energy adequacy weaknesses. Planners can even use their own recent (i.e., historical) events to evaluate the level of resource and transmission adequacy while NERC moves forward with creating a temperature-based extreme weather benchmark event library.

Determine Transmission Adequacy Requirements

Resource adequacy planning must apply the same stressed scenarios to transmission planning, though planners may consider other more impactful transmission scenarios. Using a coordinated approach between the resource and transmission planners, as discussed above, can reveal potential transmission improvements. Analysis of the impacts and limits of the transmission system under stressed scenarios can inform decisions that lead to a more robust transmission system. Improvements in the resource adequacy procurement mechanisms (including market designs and centralized resource planning) will lead to sufficient resources rather than aiming to solve an isolated problem. For example, having a more robust transmission system can reduce the criticality of individual lines and substations and lower the cost to protect and recover from events or can simply lead to the facility being deemed non-critical. This means that coordination between the planners must include a complete understanding of the design basis for threats. Incorporating physical security concepts in the design and operation of the transmission system will make the grid more resilient to cyber and physical threats.

[13] Order No. 896, Transmission System Planning Performance Requirements for Extreme Weather, 183 FERC ¶ 61,191 (2023).

Incorporating resource adequacy needs into transmission planning further assures that the needed transfer capability in extremes will be ample and most likely available. Not doing so could lead to a lack of transfer capability when transmission planning fails to consider issues like tie-line outages for the given scenario.

Comprehensive Load Forecasts

Accurate and comprehensive load forecasting is a must in resource adequacy due to the blurring lines between T&D (i.e., the effects of DER on the BPS). The evolving grid now requires load forecasts that account for electric distribution resources. This is important to determine the impacts at the T&D interface and the complexities revealed between the BPS resource mix, DER, and distribution load changes due to electrification, all of which may have a greater impact than overall extreme climate-spawned extreme events and tail risks.

Figure 2.4 is a scenario for Winter Storm Elliott taken directly from ERCOT's *Monthly Outlook for Resource Adequacy* (MORA)[14] showing the hourly risk assessment of capacity available for operating reserves (CAFOR). A deterministic analysis shows that ERCOT would have about a 25% PRM for a severe winter storm scenario in February 2024, indicating the potential lack of available resources at the peak hours. It is important that load forecasts be comprehensive such that chronological studies can be performed to assess resource adequacy.

There is a need for better coordination at the T&D interface and better behind-the-meter DER visibility to inform BPS planning. Increased visibility using operational data will enable planners to model shifts in peak loads for chronological studies. In addition, operators need this visibility in the magnitude in load reduction and resource dispatching capability. More data on the statistical distribution of expected load loss is needed to help quantify forecasting to support adequacy studies. Additionally, significant improvements in demand-side management (both energy efficiency and demand response) are necessary and an important variable in the forecasting process. DERs currently mask the gross load at the T&D interface and can lead to inaccurate representation of the total potential demand on the system. Planners need better data to understand shifts in net peak load, energy storage charging and discharging characteristics, and accurate correlated climate data.

	EMERGENCY LEVEL		
	Chance of Normal System Conditions	Chance of an Energy Emergency Alert	Chance of Ordering Controlled Outages
Hour Ending	Probability of CAFOR being above 3,000 MW	Probability of CAFOR being less than 2,500 MW	Probability of CAFOR being less than 1,500 MW
1 a.m.	89.07%	3.56%	1.68%
2 a.m.	88.53%	3.39%	1.74%
3 a.m.	89.79%	2.88%	1.31%
4 a.m.	90.67%	2.50%	1.23%
5 a.m.	87.82%	4.69%	2.65%
6 a.m.	84.75%	6.90%	4.37%
7 a.m.	80.08%	11.35%	8.24%
8 a.m.	71.92%	18.27%	14.66%
9 a.m.	86.55%	6.12%	3.98%
10 a.m.	94.38%	2.25%	1.18%
11 a.m.	97.62%	0.65%	0.20%
12 p.m.	99.82%	0.02%	0.00%
1 p.m.	100.00%	0.00%	0.00%
2 p.m.	100.00%	0.00%	0.00%
3 p.m.	100.00%	0.00%	0.00%
4 p.m.	100.00%	0.00%	0.00%
5 p.m.	100.00%	0.00%	0.00%
6 p.m.	100.00%	0.00%	0.00%
7 p.m.	90.65%	1.69%	0.56%
8 p.m.	92.06%	1.66%	0.69%
9 p.m.	93.31%	1.39%	0.59%
10 p.m.	95.79%	0.64%	0.18%
11 p.m.	99.04%	0.04%	0.02%
12 a.m.	99.72%	0.00%	0.00%

Note: Probabilities are not additive.

Figure 2.4: Scenario Assuming Winter Storm Elliott Weather Conditions Above Typical Emergency Level

[14] *Monthly Outlook for Resource Adequacy* (MORA), ERCOT, Reporting Month: February 2024, Report Date: December 1, 2023, p. 2 at MORA February 2024.pdf (ercot.com).

In summary, just as DER and load can negatively impact the BPS when not adequately planned and coordinated, a T&D planning and investment prioritization framework is required to maximize operational objectives and reduce costs. There is a further need to address the tools and processes for implementing such a coordinated framework. These include tools for steady-state and dynamic modeling of all the new technologies like IBRs, storage devices, new electronic controllers, digital protective devices, communications, and other such components.

Monte Carlo Simulations

Monte Carlo simulations can be used to cover a large range of scenarios to calculate risk levels. The simulations can provide an understanding of what tail risks to plan to (i.e., cyber and physical risks, including climate-induced weather and environmental conditions). The PEAT being used by ISO-NE introduces an innovative approach to evaluate energy adequacy risk quantitatively and probabilistically under extreme weather events within an operational time frame. ISO-NE collaborated with the Electric Power Research Institute (EPRI) and developed PEAT for assessing energy adequacy risks and system resilience. Initial studies using PEAT focused on the 2027 and 2032 study years and provided insights on the regional energy shortfall risks as climate projections and the resource mix evolve. More information is provided in the ISO-NE *Final Report on the PEAT Framework and 2027/2032 Study Results*.[15]

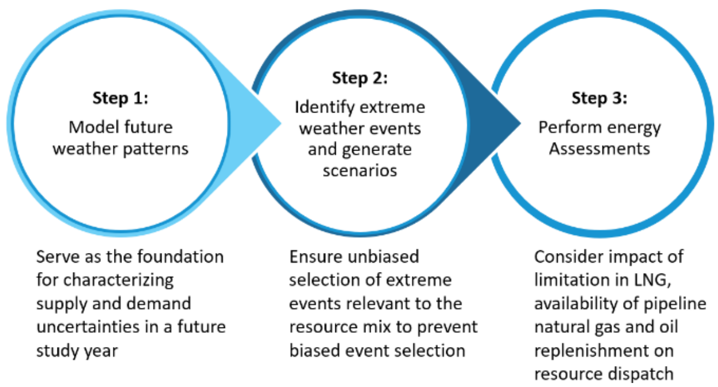


Figure 2.5: PEAT Framework

The PEAT framework (**Figure 2.5**) stress tests the ISO-NE power system's resilience to extreme weather conditions from an energy balance perspective without considering the transmission system. While not focusing on a long-term planning perspective, PEAT evaluates the power system's capability to manage disruptions in energy demand and supply over a 21-day period.

Monte Carlo simulations can also help with estimating the impacts associated with the loss of certain facilities. This demonstrates the need to incorporate stochastic/probabilistic approaches using Monte Carlo as one of the key tools rather than relying on only deterministic approaches. Monte Carlo simulations can help inform energy budgets for various climate conditions (e.g., droughts), hydro run-of-the-river-flow management, energy storage impact, natural gas supply modeling (which is not well established), replenishment of on-site fuel (e.g., oil), and the emergence of new technologies.

[15] Operational Impact of Extreme Weather Events: *Final Report on the Probabilistic Energy Adequacy Tool (PEAT) Framework and 2027/2032 Study Results,* ISO-NE, December 2023.

Chapter 3: Next Steps for NERC Reliability Assessments

This chapter details the near-term actions that NERC will take in the improvement of the energy assessment portion of its annual 10-year LTRA. The focal point is the adoption of an energy adequacy benchmark to help evaluate energy adequacy risk across each assessment area in North America.

NERC Long-Term Reliability Assessments

In addition to the individual planning analyses conducted by industry, NERC conducts annual reliability assessments of the North American BPS.[16] Each year, NERC is responsible for independently assessing and reporting on the overall reliability, adequacy, and associated risks that could impact the upcoming summer and winter seasons as well as the long-term, 10-year period.

The analytical processes used for the LTRA range from relatively simple calculations of PRM to rigorous reliability simulations that employ LOLH and EUE values. The 1-day-in-10 LOLE based RML is a target for the PRM to meet. This planning criterion requires an electric system to maintain sufficient capacity such that system peak load is not likely to exceed available supply for more than a 1-day-in-10 period. Utilities, system operators, and regulators across North America rely on variations of the 1-event-in-10-year criterion for ensuring and maintaining resource adequacy. Midcontinent Independent System Operator (MISO) highlighted its continual effort to explore alternative resource adequacy metrics and targets over the traditional reliability criterion shown in **Figure 3.1**.

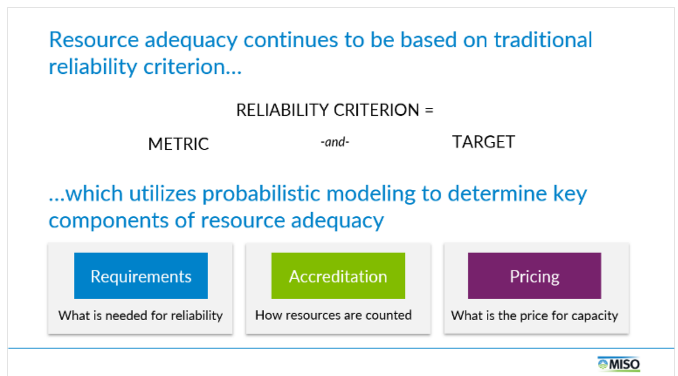


Figure 3.1: Reliability Criterion

To identify high-risk periods and potential energy constraints resulting in load-loss events, NERC assesses load-loss metrics LOLH and EUE from probability-based simulations of projected demand and resource availability over all hours. Consideration of wide area perspectives, evaluation of extreme conditions, reliance on neighboring areas, and transmission constraints in these assessments is insufficient. Therefore, the improvement actions described in the next section are being implemented across the ERO Enterprise.

Reliability Assessment Improvement Actions

No one metric is the solution, and multi-metric criteria are needed to consider the magnitude, frequency, duration, and timing of energy shortfalls. Therefore, NERC is pursuing the following measurement improvements to its LTRA evaluation process:

- **Enhanced Risk Measures:** In addition to the evaluation of the equivalent 1-day-in-10 years reserve margin, the LTRA[17] will continue to evaluate EUE and LOLH metrics[18] and will provide more hourly resolution on the impact and duration of loss-of-load events.
  - **Loss of Load Hours**: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the hourly resource capability, commonly referred to as a load-loss event.

[16] NERC conducts four annual assessments: Long-Term, Summer, Winter, and Case Quality Metrics on modeling.
[17] *2023 Long-Term Reliability Assessment*, NERC, December 2023.
[18] NERC's ProbA work maintains the calculation of the (monthly) EUE and LOLH probabilistic indices for Base and Scenario/Sensitivity Cases for the LTRA. See 2022 NERC Probabilistic Assessment (ProbA): Regional Risk Scenario Sensitivity Case, June 2023.

- This metric is calculated by counting each hourly load-loss event in the given time period. LOLH is evaluated using all hours rather than just peak periods and is applicable to both small and large systems. It can be evaluated over annual, seasonal, monthly, or weekly study horizons. LOLH does not specify the magnitude or frequency of load-loss events but is used as a measure of their combined duration. LOLH provides insight into the impact of the variable nature of energy-limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Such energy-limited resources include the following:
  - Demand-response programs, which can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
  - Energy-efficiency programs, which can be modeled as reductions to load with an hourly load shape impact
  - DERs, such as behind-the-meter photovoltaic (solar), which can be modeled as reductions to load with an hourly load shape impact
  - Variable energy resources, such as wind and solar
- **Expected Unserved Energy**: EUE is a probabilistic average calculated by summing the amount of energy demand that will not be served for each time period as a result of energy demand exceeding the available supply across all hours. EUE is an energy-centric metric that considers the magnitude for all hours of the time period.[19]
  - When EUE is normalized based on various components of an assessment area (e.g., total area annual energy), NERC refers to this measure as NEUE or ppm. Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).
  - EUE is the only metric that considers the magnitude of load-loss events. With the changing generation mix, to make the EUE metric more effective, hourly EUE for each month provides insights on potential adequacy risk during shoulder and non-peak hours. EUE is very useful in estimating the magnitude of load-loss events so the planners can estimate the cost and impact. EUE can be used as a basis for RML determination in combination with or as an alternative to the 1-day-in-10 LOLE. In addition, the EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.
  - The AEMO is responsible for power system planning in Australia and uses a NEUE of ≤ 0.002%[20] as its energy adequacy requirement.[21]

- **Reliability Benchmark for Assessment:** Thresholds for assessing risk of load-loss hours based on annual LOLH and EUE will be evaluated as follows:
  - LOLH Risk Threshold: Annual LOLH (hours per year)
    - High: Greater than 2.4 hours/year
      - Medium: Between 0.1 and 2.4 hours/year
      - Low: Less than 0.1 hours/year

[19] EUE is the amount of energy including the PRM generally expressed in MWhrs.
[20] Often expressed in "ppm" or parts per million of total energy served or as a percentage.
[21] A NEUE of ≤ 0.002% is consistent with the NEUE metrics of several countries around the world, including that of the Australian Energy Market Operator (AEMO), which has significant renewable across the continent with Tasmania reaching 100% in 2023.

- EUE Risk Threshold: Annual Normalized EUE to Total Energy[22] – calculated over an assessment area and interconnection:
  - High: Greater than 0.002% of total system energy
  - Medium: Less than or equal to 0.002% of total system energy
  - Low: Negligible or zero (0.0%)

- **Common Tool and Internally Consistent Assumptions:** The ERO is developing a new reliability assessment process that includes a wide-area energy assessment using a common tool. Because the current process relies on industry studies each with their own set of assumptions, tools, and methods, a consistent approach to assessment over a wider area will more effectively measure energy adequacy, particularly under extreme weather events making an area highly reliant on long-distance transfers. Neighboring interconnected systems may also be undergoing similar weather or climate events and as a result may not be able to provide the support required during an emergency. This approach is similar to the REST initiative that will be established in ISO-NE to reflect the assessment area risk tolerance with respect to energy shortfalls during extreme weather. The ISO-NE energy adequacy studies using PEAT are expected to play an important role in informing the development of REST in 2024.

[22] NEUE is the ratio of energy relative to total annual load including the PRM and is generally expressed as a percentage.

Chapter 4: Recommendations and Next Steps

Recommendations (NERC Actions):

I. **Achieve consistency in resource adequacy planning:** To achieve consistency in resource adequacy planning, NERC should request industry stakeholders through its Reliability and Security Technical Committee (RSTC) to develop a white paper or reliability guideline of best practices for resource adequacy modeling. Additionally, NERC should educate policymakers on the need to align policies to create cohesiveness within assessment areas.

II. **Address the duration and magnitude of load loss:** NERC should begin working to establish evaluation methods (e.g., visualizations) for the LOLH and EUE metrics that help account for the loss of fidelity when LOLE aggregates duration and magnitude load-loss risks. Establishing thresholds for metrics that supplement LOLE will allow industry to measure it themselves and understand risks. The LOLH and EUE metrics may be specific to each interconnection. To accomplish this, NERC may request industry stakeholders through the RSTC to develop consensus around threshold values. Furthermore, NERC may need to institute new data collection that will facilitate the calculation of appropriate LOLH and EUE metrics or other criteria.

III. **Coordinate study on generation and transmission adequacy to the extent possible:** To ensure enhanced coordination, NERC should request industry stakeholders through the RSTC to develop a white paper, practice guide, or reliability guideline covering key elements that the resource and transmission planners should consider as part of their adequacy planning, including the effects of energy-constrained resources and the potential for increased transfers during a particular scenario or stressed condition. Should NERC's enhanced tracking of adequacy metrics reveal a need to establish a threshold, NERC may propose establishing a threshold through the NERC Reliability Standards process. There should be a minimum set of information or data established between resource and transmission planners that considers needs beyond the operations horizon (less than 1 year) and long-term planning horizon (10 years).[23]

IV. **Assure that chronological studies for transmission planning are conducted:** All planners need chronological studies to ensure energy adequacy across all hours. NERC should consider initiating a pilot study among a small group of transmission planners to assess the benefits of Monte Carlo simulations over every hour. Chronological studies could inform the existing deterministic transmission planning assessment process by identifying additional critical hours. Coordination between the transmission and resource planners is required and the pilot should aim to reveal the most valuable insights and observations in the chronological studies that require more analysis. The results should inform NERC and the resource and transmission planners whether a subsequent practice guide or reliability guideline would be a sufficient next step or whether a NERC Reliability Standard is needed to require enhanced chronological studies.

V. **Include stressed scenarios in the resource and transmission planning process:** Although a NERC project is developing a Reliability Standard specifically addressing extreme heat and cold weather planning scenarios, planners should not wait for this standard, which is anticipated to be completed by industry in 2024. The standard will still require regulatory approval along with a defined implementation period. In the meantime, planners should use historical information and other sources to develop their own extreme or stressful scenarios based on good engineering judgment. In doing so, some planners might be able to provide insight to NERC once it begins to develop Reliability Standards for other normal and extreme natural weather, DER, and gas–electricity interconnectedness energy adequacy scenarios.

[23] See also Order No. 1920, paragraph 859.

VI. **Determine transmission energy adequacy for stressed resource adequacy scenarios:** NERC should facilitate an industry forum or task force to evaluate the potential opportunities for increasing the robustness of the grid while reducing the criticality of certain resources and transmission facilities. NERC's 2024 work performing the U.S. congressionally mandated ITCS could inform opportunities to not only improve reliability but also the robustness and resilience of the BPS. A failure to account for impacts on transmission during extreme conditions can result in energy shortfalls and loss of load.

VII. **Ensure a more comprehensive approach to load forecasting by planners:** Planners must consider distribution-level utility-scale DER, behind-the-meter DER, and electrification impacts. Additionally, planners must develop ways to unmask the net load to determine the underlying potential impacts of DER on the T&D interface. Certain NERC Reliability Standard development projects delve into this area. For example, some NERC Reliability Standards projects aim to improve the load data required to be provided by the NERC-registered Distribution Provider (DP) function to the planner for BPS modeling, to require the DP to have interconnection processes for its distribution system, and to require NERC-registered Transmission Planner functions to explicitly model DER in their BPS annual planning assessment(s).[24] NERC should evaluate whether its current Reliability Standards work addresses the comprehensiveness of load forecasts sufficiently. If supplemental work is necessary, NERC should determine whether to augment its Reliability Standards by creating/revising a Reliability Standard to ensure that the DP is obligated to conduct comprehensive load forecasts that include the necessary inputs for resource and transmission adequacy. The framework should also require enhanced tools for steady-state and dynamic modeling of new technologies like IBRs and other components, including electromagnetic transient simulation.

VIII. **Standardize the use of Monte Carlo simulations as a tool for resource and transmission adequacy planning:** NERC should lead industry toward using Monte Carlo simulations as an integral tool for revealing risks associated with resource and transmission adequacy. Simulations can be used to cover a large range of scenarios to calculate risk levels. Using the simulations in coordination between the resource and transmission planner, to the extent possible given some market constructs, will reveal potential areas of unserved energy as an initial study step. Subsequent deterministic studies can then measure the more specific and localized risks, tail risks, and associated cost of implementing a corrective action plan.

IX. **Continue Enhancing NERC's annual 10-year assessment, the LTRA, with enhanced energy metrics that more accurately measure the energy frequency, event duration, and event magnitude reliability risks:** NERC will adopt assessment thresholds that include EUE or a normalized NEUE (> 0.002% will be considered "high risk") and LOLH (> 2.4 hours per year will be considered "high risk"). These additional metrics provide higher resolution compared to the current LOLE representation, which treats all energy shortfalls equally. Further refinements are expected as EUE and LOLH metrics used for the LTRA should reflect the unique characteristics of each area's demand, generation fleet reliability, and transmission system topology. Further enhancements are expected toward differentiating scenarios that represent a loss of large amounts of load for a short duration compared to the loss of smaller amounts of load for a long duration.

Next Steps

NERC will work with its technical committees[25] and industry stakeholders to incorporate enhanced resource adequacy modeling into all planning processes. In addition, NERC will need to educate federal, state, and local regulators on the need to evolve planning modeling processes due to the changing grid. To measure the changes in resource planning, NERC will assess resource adequacy according to the described metrics for EUE, LOLH, and LOLE.

[24] Capitalized DP and Transmission Planner terms are functional registration designations according to their NERC-defined roles and responsibilities.
[25] For example, the Probabilistic Assessment Working Group (PAWG) and Reliability Assessment Subcommittee (RAS).

NERC will ensure adoption of consistent interconnection-wide methods and programs to ensure consistency throughout an interconnection. Lastly, NERC should improve the understanding of frequency, duration, magnitude, and timing of events to evaluate each criterion for adjustment.

For the probabilistic modeling perspective, NERC will help industry implement chronological studies that can provide insight to potential shortfall risks in periods other than the peak hour(s). NERC will then take another step to help industry use deterministic modeling to further study specific issues that may arise, especially in adverse climate conditions. NERC is undertaking steps to continue moving the needle forward through the formation of a library for extreme heat and cold temperature events that can be used to construct normal and extreme weather-based scenarios.

NERC plans to socialize this report and recommendations via future workshops through groups like NERC's RSTC; the IEEE Power System Operation, Planning and Economics (PSOPE) technical committee meeting at the IEEE Power and Energy Society General Meeting in Seattle in July 2024; the Conseil International des Grands Réseaux Électriques "Grid of the Future" conference in Raleigh, North Carolina in November 2024; and the IEEE Grid Edge conference in San Diego in January 2025.

Chapter 5: Conclusion

Traditional resource adequacy models and approaches rooted in a LOLE of 1-day-in-10 years do not adequately account for the essential role that electricity plays in modern society. Pre-distributed reports identified the need to act to address resource adequacy planning due to the limitations of LOLE. ISO-NE's REST, to be developed further this year, will serve as an energy adequacy criterion for extreme weather events, which aligns with several recommendations in the ESIG report. This initiative is expected to be a collaborative process with regional stakeholders, including the six New England states. A portion of the ESIG survey[26] shown in **Figure 5.1** underscores that a multi-metric approach is necessary and that EUE should be a component of resource adequacy planning.

Resource and transmission adequacy studies must be coordinated to capture their interrelated impacts. A white paper, practice guide, or reliability guideline for resource and transmission planners will assure that key study elements and methods are included in adequacy planning. In addition, a pilot study will assess improvements and the benefits achieved through these recommendations. These efforts combined with study beyond the 10-year horizon are integral to assuring resource and transmission adequacy.

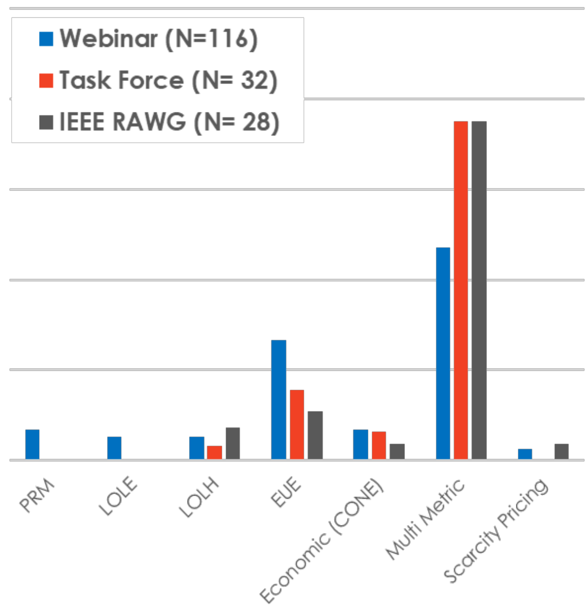


Figure 5.1: ESIG Survey Question—If You Had to Pick One Resource Adequacy Criterion, Which Would You Pick?

NERC recommends thresholds for assessing the risk of LOLE based on annual EUE and LOLH. Annual EUE thresholds that are zero or near zero will be considered low, NEUE less than or equal to 0.002% as medium, and any NEUE greater than 0.002% as high. For total energy, it should be annualized (calculated as a percentage) over an assessment area and interconnection. Annual LOLH thresholds of less than 0.1 will be considered low, thresholds between 0.1 and 2.4 as medium, and any hours above 2.4 as high. Planners must incorporate the anticipated effects of extreme weather.

In addition to the evaluation of the equivalent 1-day-in-10 years criterion, NERC will begin evaluating the EUE, NEUE, and LOLH metrics in its LTRA and provide greater resolution on the impact and duration of loss-of-load events.

As stated before, no one metric is the solution. NERC's work with industry and groups like the NAE Section 6 will continue the discussion and move the needle toward a more reliable, resilient, and secure BPS across North America.

[26] New Resource Adequacy Criteria for the Energy Transition Modernizing Reliability Requirements, March 2024, Figure 1, p. 12.

Appendix A: Workshop Agenda

7:00–8:00 Breakfast

8:00 Call to Order

Facilitator's Remarks – Scott Barfield-McGinnis, Principal Technical Advisor, NERC *(5 minutes*)

Agenda

1. **Safety Briefing – AFC Building Engineer *(2 minutes*)**
2. **Introduction – Anjan Bose, Regents Professor – Distinguished Professor in Power Engineering, Washington State University (*10 minutes)***
3. **Keynote – Jim Robb, President and CEO, NERC (*10 minutes)***
4. **Market Considerations – Gordon van Welie, President and CEO, ISO-NE *(5 minutes)***

8:30–9:30 Presentations

5. **Presenters 1–4 *(15 minutes each/order subject to change)***
   a. John Moura, Director, Reliability Assessments and Technical Committees, NERC
   b. Andrew Macdonell, Senior Policy Manager, Office of Gas and Electricity Markets (OFGEM), United Kingdom
   c. Derek Stenclik, Founding Partner, Telos Energy (representing Energy Systems Integration Group (ESIG))
   d. Duane Highley, Chief Executive Officer, Tri-State Generation and Transmission

9:30–9:45 Break *(15 minutes*)

9:45–10:50 Presentations

6. **Presenters 5–8 *(15 minutes each/order subject to change)***
   a. Aditya Jayam Prabhakar, Director of Resource Assessment and Planning, CAISO
   b. Eduardo Ibanez, Advisor, Strategic Insights, Midcontinent ISO (MISO)
   c. Jinye Zhao, Technical Manager, ISO New England
   d. Woody Rickerson, Senior Vice President and Chief Operating Officer, ERCOT
7. **Instructions for Breakout and Lunch Schedule – Scott Barfield-McGinnis *(5 minutes)***

10:50–11:05 Break and Transition from AFC to NERC *(15 minutes)*

11:05–12:35 Breakout Sessions Part 1 *(90 minutes)*

8. **Session 1: Generation – 611**
   a. Moderator – Richard Burt, Senior Vice President and COO, Midwest Reliability Organization (MRO)
   b. Scribe – Svetlana Ekisheva, Principal Data Science Advisor, NERC
      i. Aditya Jayam Prabhakar, Director of Resource Assessment and Planning, CAISO

ii. Andrew Macdonell, Senior Policy Manager, OFGEM
iii. Anna Lafoyiannis, Technical Leader, Resource Planning for EPRI
iv. Brett Kruse, Vice President of Market Design, Calpine
v. David Mulcahy, Power System Modeler, Illuminate Power Analytics
vi. Denise Buffington, Senior Director, Federal Regulatory Affairs, Evergy
vii. Eduardo Ibanez, Advisor, Strategic Initiatives, MISO
viii. Gilbert Bindewald III, Principal Deputy Assistant Secretary, Department of Energy
ix. Jinye (Jeannie) Zhao, Technical Manager, ISO-NE
x. Vijay Vittal, Regents Professor, Ira A. Fulton Chair Professor, Arizona State University

9. **Session 2: Generation – 612**
   a. Moderator – Mark Henry, Chief Engineer and Director, Reliability Outreach, Texas Reliability Entity
   b. Scribe – Hugo Perez, Manager of North American Relations, NERC
      i. Adam Keech, Vice President Market Design and Economics, PJM Interconnection, LLC
      ii. Chanan Singh, Distinguished Professor, Regents Professor & Irma Runyon Chair Professor, Texas A&M University
      iii. David Richardson, Supervisor Planning Models, Independent Electricity System Operator (IESO), Canada
      iv. Derek Stenclik, Founding Partner, Telos Energy (representing ESIG)
      v. Duane Highley, Chief Executive Officer, Tri-State Generation and Transmission
      vi. Francis Bradley, President and CEO, Electricity Canada
      vii. Jay Giri, Chair of NAE Section 6, National Academy of Engineering
      viii. Philip Fedora, Vice President and Chief Engineer, Northeast Power Coordinating Council (NPCC)
      ix. Rich Hydzik, Principal System Operations Engineer, Avista Corp
      x. Robert Friel, Policy Representative, Apteno Consulting Ltd (representing the Royal Academy of Engineering)
      xi. Woody Rickerson, Senior Vice President and Chief Operating Officer, ERCOT

10. **Session 3: Transmission – 7th Floor Executive Boardroom**
   a. Moderator – Tim Ponseti, Vice President, Operations, SERC
   b. Scribe – Elsa Prince, Principal Technical Advisor, NERC
      i. Andrew Arana, Director, Real Zero - Grid Planning, Florida Power & Light
      ii. Andrea Koch, Senior Director, Reliability Policy, Edison Electric Institute
      iii. Damir Novosel, President and Founder, Quanta Technology

iv. Eric Vandenberg, Deputy Director, Office of Electric Reliability, Federal Energy Regulatory Commission (FERC)

v. Gordon van Welie, President and Chief Executive Officer, ISO New England

vi. Jim Robb, President and Chief Executive Officer, NERC

vii. Mark Carpenter, Senior Vice President T&D Operations, Oncor Electric Delivery Company

viii. Nelson Peeler, Senior Vice President, Grid Strategy, Planning & Integration, Duke Energy

ix. Thomas Overbye, Professor – Department of Electrical and Computer Engineering, Texas A&M University

x. Todd Lucas, Vice President Transmission Operations & Policy, Southern Company

11. Session 4: Transmission – 604

a. Moderator – Branden Sudduth, Vice President, Reliability Planning and Performance Analysis, WECC

b. Scribe – Maria Kachadurian, Principal Analyst, NERC

i. Anjan Bose, Regents Professor - Distinguished Professor in Power Engineering, Washington State University

ii. Bob Bradish, Senior Vice President Infrastructure Planning, American Electric Power (AEP)

iii. Edison Elizeh, Director, Regional & National Initiatives, Bonneville Power Administration (BPA)

iv. Elliott Nethercutt, Principal Regulatory Policy Specialist, National Association of Regulatory Utility Commissioners (NARUC)

v. Eric Brown, Director, GridScientific (representing Royal Academy of Engineering)

vi. Kevin Carden, Chief Executive Officer, Astrape Consulting

vii. Marcus Hawkins, Executive Director, MISO States

viii. Paul Turner, Vice President Power Delivery, Georgia System Operations Corporation

ix. Rob Manning, Trustee, NERC Board of Trustees

x. Teresa Mogensen, Chair, President & Chief Executive Officer, American Transmission Company (ATC)

xi. Tom Galloway, President and Chief Executive Officer, North American Transmission Forum (NATF)

12:35–12:55 Lunch (staggered) *(20 minutes)*

12:55–2:25 Breakout Sessions Part 2: Sessions 1–4 Continued *(90 minutes)*

2:25–2:35 Break *(10 minutes)*

2:35–4:30 Closing Session *(115 minutes)*

12. Breakout Reporting – Moderators *(70 minutes)*

13. **Actionable Takeaways – John Moura; Mark Lauby, Senior Vice President and Chief Engineer, NERC; Moderators *(30 minutes)***

14. **Closing Remarks – Mark Lauby; Anjan Bose *(15 minutes)***

4:30 Adjourn

Appendix B: Participant Roster

Table B.1: Workshop Participants		
Attendee Name	**Title**	**Organization**
Arana, Andrew	Director of Real Zero - Grid Planning	Florida Power & Light
Bindewald III, Gilbert	Principal Deputy Assistant Secretary	Department of Energy (DOE)
Bose, Anjan	Regents Professor - Distinguished Professor in Power Engineering	Washington State University
Bradish, Bob	Senior Vice President Infrastructure Planning	American Electric Power (AEP)
Bradley, Francis	President and CEO	Electricity Canada
Brown, Eric	Director	GridScientific (representing the Royal Academy of Engineering)
Buffington, Denise	Senior Director, Federal Regulatory Affairs	Evergy
Burt, Richard	Senior Vice President and Chief Operating Officer	Midwest Reliability Organization (MRO)
Carden, Kevin	Chief Executive Officer	Astrape Consulting
Carpenter, Mark	Senior Vice President T&D Operations	Oncor Electric Delivery Company
Elizeh, Edison	Director, Regional & National Initiatives	Bonneville Power Administration (BPA)
Fedora, Philip	Vice President and Chief Engineer	Northeast Power Coordinating Council (NPCC)
Friel, Robert	Policy Representative	Apteno Consulting Ltd (representing the Royal Academy of Engineering)
Galloway, Tom	Chief Executive Officer	North American Transmission Forum
Giri, Jay	Chair of NAE Section 6	National Academy of Engineering
Hawkins, Marcus	Executive Director	MISO States
Henry, Mark	Chief Engineer and Director, Reliability Outreach	Texas Reliability Entity
Highley, Duane	Chief Executive Officer	Tri-State G&T
Hydzik, Rich	Principal System Operations Engineer	Avista Corp
Ibanez, Eduardo	Advisor, Strategic Initiatives	Midcontinent ISO (MISO)
Jayam Prabhakar, Aditya	Director of Resource Assessment and Planning	California ISO (CAISO)
Keech, Adam	Vice President Market Design and Economics	PJM Interconnection, LLC

Table B.1: Workshop Participants		
Attendee Name	**Title**	**Organization**
Kim, Soo Jin	Vice President, Engineering and Standards	NERC
Koch, Andrea	Senior Director, Reliability Policy	Edison Electric Institute
Kruse, Brett	Vice President of Market Design	Calpine
Lafoyiannis, Anna	Technical Leader, Resource Planning for Electric Power Systems	Electric Power and Research Institute (EPRI)
Leslie, Julian	Director of Strategic Energy Planning and Chief Engineer	National Grid Electric System Operator
Lauby, Mark	Senior Vice President and Chief Engineer	NERC
Lucas, Todd	Vice President Transmission Operations & Policy	Southern Company
Macdonell, Andrew	Senior Policy Manager	OFGEM – Office of Gas and Electricity Markets
Manning, Rob	Trustee	NERC Board of Trustees
Mogensen, Teresa	Chief Executive Officer	American Transmission Company (ATC)
Moura, John	Director, Reliability Assessments and Technical Committees	NERC
Mulcahy, David	Power System Modeler	Illuminate Power Analytics
Nethercutt, Elliott	Principal Regulatory Policy Specialist	National Association of Regulatory Utility Commissioners (NARUC)
Novosel, Damir	President and Founder	Quanta Technology
Overbye, Thomas	Professor - Department of Electrical and Computer Engineering	Texas A&M University
Peeler, Nelson	Senior Vice President, Grid Strategy, Planning & Integration	Duke Energy
Ponseti, Tim	Vice President, Operations	SERC
Richardson, David	Supervisor Planning Models	Independent Electricity System Operator (IESO)
Rickerson, Woody	Senior Vice President and Chief Operating Officer	Electric Reliability Council of Texas (ERCOT)
Robb, Jim	President and Chief Executive Officer	NERC
Singh, Chanan	Distinguished Professor, Regents Professor & Irma Runyon Chair Professor	Texas A&M University
Stenclik, Derek	Founding Partner	Telos Energy (representing ESIG)

Table B.1: Workshop Participants		
Attendee Name	**Title**	**Organization**
Sudduth, Branden	Vice President, Reliability Planning and Performance Analysis	WECC
Turner, Paul	Vice President Power Delivery	Georgia System Operations Corporation
van Welie, Gordon	President and CEO	ISO-NE
Vandenberg, Eric	Deputy Director, Office of Electric Reliability	Federal Energy Regulatory Commission (FERC)
Vittal, Vijay	Regents Professor, Ira A. Fulton Chair Professor	Arizona State University
Zhao, Jinye	Technical Manager	ISO-NE

Table B.2: NERC Workshop Participants		
NERC Staff	**Title**	**Role**
Barfield-McGinnis, Scott	Principal Technical Advisor	Workshop Coordinator
Lawrence, Stephanie	Senior Program Specialist	Workshop Administrator
Ekisheva, Svetlana	Principal Data Science Advisor	Scribe
Kachadurian, Maria	Principal Analyst	Scribe
Perez, Hugo	Manager of North American Relations	Scribe
Prince, Elsa	Principal Technical Advisor	Scribe

Appendix C: Authors and Contributors

Anjan Bose, Regents Professor – Distinguished Professor in Power Engineering, Washington State University

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Elsa Prince, Principal Technical Advisor, NERC

Gordon van Welie, President and CEO, ISO New England

Hugo Perez, Manager of North American Relations, NERC

Jay Giri, Chair of NAE Section 6, NAE

John Moura, Director, Reliability Assessments and Technical Committees, NERC

Maria Kachadurian, Principal Analyst, NERC

Mark Lauby, Senior Vice President and Chief Engineer, NERC

Murty Bhavaraju, retired, PJM

Scott Barfield-McGinnis, Principal Technical Advisor, NERC

Stephanie Lawrence, Senior Program Specialist, NERC

Svetlana Ekisheva, Principal Data Science Advisor, NERC

Thomas Overby, Professor - Department of Electrical and Computer Engineering, Texas A&M University

Vijay Vittal, Regents Professor, Ira A. Fulton Chair Professor, Arizona State University

Appendix D: Abbreviations and Acronyms

AEMO	Australian Energy Market Operator
AEP	American Electric Power
ATC	American Transmission Company
BPA	Bonneville Power Administration
BPS	Bulk power system
CAFOR	Capacity Available for Operating Reserves
CAISO	California Independent System Operator
CAMX	California-Mexico
DER	Distributed energy resources
DOE	Department of Energy
DP	NERC Distribution Provider function
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability of Texas
ERO	Electric Reliability Organization (NERC and the six Regional Entities)
ESIG	Energy Systems Integration Group
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
ISO-NE	Independent System Operator New England
ISO	Independent System Operator
ITCS	Interregional Transfer Capability Study
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	NERC Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
MORA	ERCOT Monthly Outlook for Resource Adequacy
MRO	Midwest Reliability Organization
MW	Megawatt
MWhrs	Megawatt hour
NAE	National Academy of Engineering
NARUC	National Association of Regulatory Utility Commissioners

NEM	National Energy Market
NERC	North American Electric Reliability Corporation
NEUE	Normalized Expected Unserved Energy
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
OFGEM	Office of Gas and Electricity Markets
PAWG	Probabilistic Assessment Working Group
PEAT	ISO-NE Probabilistic Energy Adequacy Tool
PJM	PJM
ppm	parts per million
PRM	Planning Reserve Margin
PSOPE	IEEE Power System Operation, Planning and Economics (committee)
PUC	Public Utility Commission
RAWG	IEEE Reliability Assessment Working Group
RAS	Reliability Assessment Subcommittee
REST	ISO-NE Regional Energy Shortfall Threshold
RML	Reference Margin Level
RSTC	NERC Reliability and Security Technical Committee
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPL	Transmission Planning (set of NERC Reliability Standards)
T&D	Transmission and Distribution