NARUC
National Association of Regulatory Utility Commissioners

Resource Adequacy for State Utility Regulators:
Current Practices and Emerging Reforms

November 2023

Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-OE0000925. NARUC thanks the following individuals for their information and contributions in the development of this report:

Report Leadership

- **Ann Rendahl,** Washington Utilities and Transportation Commission
- **Matthew Schuerger,** Minnesota Public Utilities Commission

NARUC Staff

- **Sarah Fitzpatrick,** National Association of Regulatory Utility Commissioners
- **Jeff Loiter,** National Association of Regulatory Utility Commissioners
- **Elliott J. Nethercutt,** National Association of Regulatory Utility Commissioners
- **Danielle Sass Byrnett,** National Association of Regulatory Utility Commissioners

Authors / Contributors

- **Gabriel Aguilera,** New Mexico Public Regulation Commission
- **Rizwana Alamgir-Arif,** New Hampshire Public Utilities Commission
- **Abigail Anthony,** Rhode Island Public Utilities Commission
- **Harika Basaran,** Public Utility Commission of Texas
- **Todd Bianco,** Rhode Island Public Utilities Commission
- **Simone Brant,** California Public Utilities Commission
- **Kacia Brockman,** Oregon Public Utilities Commission
- **Kent A. Chandler,** Kentucky Public Service Commission
- **Joey Chen,** Maryland Public Service Commission
- **Rory Christian,** New York State Public Service Commission
- **Cathy Cole,** Michigan Public Service Commission
- **Ben Deitchman,** Georgia Public Service Commission
- **Phillip Ellis,** Florida Public Service Commission
- **Cynthia Enriquez,** New Mexico Public Regulation Commission
- **Andrew Fay,** Florida Public Service Commission
- **Andrew J.** French, Kansas Corporation Commission
- **Mark Futrell,** Florida Public Service Commission
- **Ron Guay,** Maine Public Utilities Commission
- **Amy Hicks,** Georgia Public Service Commission
- **Warren Hicks,** North Carolina Utilities Commission
- **Darcie L. Houck,** California Public Utilities Commission
- **Mary Jo Krowelski,** Vermont Public Utility Commission
- **Maryam Mozafari,** California Public Utilities Commission
- **Brendan Ok,** Public Utility Commission of Texas
- **Tricia Pridemore,** Georgia Public Service Commission
- **Josh Ryor,** Connecticut Public Utilities Regulatory Authority
- **Dan Scripps,** Michigan Public Service Commission

- **John Slocum,** Massachusetts Department of Public Utilities
- **Karin Sung,** California Public Utilities Commission
- **Jason Stanek,** Maryland Public Service Commission
- **Leuwam Tesfai,** California Public Utilities Commission
- **Mark Thompson,** Oregon Public Utilities Commission
- **Takira Thompson,** Florida Public Service Commission
- **George Twigg,** New England Conference of Public Utilities Commissioners
- **Jessica Waldorf,** New York State Public Service Commission

NARUC also thanks the following individuals for providing review and additional expertise:

- **Gregory V. Carmean,** Organization of PJM States (OPSI)
- **Yonghong Chen,** National Renewable Energy Laboratory (NREL)
- **Erik Ela,** Electric Power Research Institute, International Inc. (EPRI)
- **Marcus Hawkins,** Organization of MISO States (OMS)
- **Fritz Hirst,** North American Electric Reliability Corporation (NERC)
- **Anna Lafoyiannis,** Electric Power Research Institute, International Inc. (EPRI)
- **Mark Lauby,** North American Electric Reliability Corporation (NERC)
- **Debra Lew,** Energy Systems Integration Group (ESIG)
- **Carl Linvill,** Regulatory Assistance Project (RAP)
- **William McCurry,** North American Electric Reliability Corporation (NERC)
- **Maya McNichol,** Western Power Pool (WPP)
- **John Moura,** North American Electric Reliability Corporation (NERC)
- **Michael O'Brien,** Western Power Pool (WPP)
- **Mark Olson,** North American Electric Reliability Corporation (NERC)
- **Mohamed Osman,** North American Electric Reliability Corporation (NERC)
- **Molly Robertson,** Resources for the Future (RFF)
- **Abraham Silverman,** Columbia University – Center on Global Energy Policy
- **Ben Sloan,** Organization of PJM States (OPSI)
- **Derek Stenclik,** Telos Energy
- **Aidan Tuohy,** Electric Power Research Institute, International Inc. (EPRI)

Please direct questions regarding this report to Elliott J. Nethercutt, NARUC, at enethercutt@naruc.org.

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Preface

This report was developed by staff in the National Association of Regulatory Utility Commissioners (NARUC) Center for Partnerships and Innovation (CPI). Additional support was provided from commissioners, commission staff, and other technical experts to provide foundational information for state utility regulators on the evolving nature of resource adequacy for the electric system. With the changing nature of the system, state commissioners will continue to play a vital role in their respective jurisdictions. Their roles in overseeing resource decisions are growing in complexity, with consideration for customer costs, state and federal environmental requirements, extreme weather events, fuel supply limitations, generation retirements, shifting requirements for system operators, and growing levels of intermittent and energy-limited resources (e.g., wind, solar, and battery storage). Reliability concerns continue to be an urgent and immediate priority for utility regulators in most parts of the United States. The information in this report is designed to support state commissioners and their respective staff members as they navigate an evolving resource adequacy landscape to maintain reliability amidst a rapidly changing system.

Part I of this report provides a brief history of resource adequacy and why the purpose remains unchanged, despite the current of conventional frameworks. **Part II** describes the various federal, regional, state, and local regulatory authorities involved in resource adequacy processes aimed at maintaining a reliable electric system. **Part III** introduces foundational resource adequacy concepts, including the common planning standards based on probabilistic metrics, fundamental load forecasting and capacity accreditation practices, and the formulation of planning reserve margins.

Part IV explores three topics related to evolving reliability issues that were prioritized with input from the utility regulatory community. While some of these topics do not fall directly within the established resource adequacy frameworks, they are closely related:

- **Resource Adequacy Reforms & Supplemental Approaches:** Explores resource adequacy reforms currently underway to further improve reliability assessment practices, better understand the changing system attributes, and recognize the associated risks of a rapidly changing electric grid.
- **Regulatory Considerations for Extreme Weather Events:** Investigates recent regulatory and legislative actions at the state and federal levels and recommendations to address climate impacts with increased system outages resulting from recent winter cold snaps and summer heat waves.
- **The Interplay between State Resource Planning & Regional Reliability:** Examines how resource planning decisions by individual states can impact reliability across a region.

Part V of this document facilitates NARUC's goal of sharing information between state commissions with descriptions of different resource adequacy approaches, stakeholder processes, and regulatory involvement in states and regions across the country. This section is organized by different electric system areas that do not necessarily align with state boundaries. Commissioners and commission staff developed the content of each state or regional section, highlighting their regulatory involvement and engagement. This section also includes information on current and emerging resource adequacy reforms and reliability issues identified by commissions for each system.

I. The History and Purpose of Resource Adequacy

Resource adequacy is a measure of whether there are sufficient electric resources available to serve customer demand. Methods, metrics, and approaches for measuring resource adequacy can serve to inform state utility regulators as they evaluate how much utilities should invest in generation, how much new generation should be built, what type of generation should be built, and which generation can be taken out of service with consideration for the potential local and regional reliability impacts.

During the 1870s and 1880s, electric power in the United States was initially generated by smaller power plants and distributed to nearby customers in primarily urban areas, using direct current (DC) circuits (DOE, 2015). Electricity was not stored, and system operators adjusted voltage levels depending upon the customer demand. As the demand for electricity service expanded across the country, more expensive DC power systems were unable to keep up with demand, and toward the end of the nineteenth century, alternating current (AC) circuits were used instead to provide a more robust, cost-efficient method to generate and distribute power, connecting grids over long distances. Beginning with Niagara Falls, the construction of larger AC generating stations became a commercially-viable solution (PowerMag, 2022).

As the system became more integrated, connected, and commercialized across the country in the 1870s, coordination between different generators serving various load centers became increasingly important. The integration of multiple grids toward the end of the nineteenth century led to the emergence of discussions around what constitutes an appropriate level of system reliability. Specifically, the industry was exploring how a more complex electric and interconnected system could provide adequate generation to meet demand during all times, with a level of failure that would be acceptable to society. The concept of resource adequacy formally emerged during the 1930s and 40s, with the application of probabilistic analysis to establish a foundational planning standard for the electric grid that was aimed at maintaining adequate capacity (Carden & Wintermantel, 2013).[1] This standard and corresponding planning reserve margin framework became a foundational tool for system planners for decades to follow.

System planners and utility regulators had a relatively straightforward approach in anticipating system needs for most of the 20th century. During that time, there was little distinction between a resource's nameplate capacity and its operational contribution for meeting the relatively predictable fluctuations in system demand on both a daily and seasonal basis. Moreover, it was safe to assume that all resources would be uniformly available throughout the year, barring any major natural disasters. When generators did fail, or when load was higher than expected, forced outages occurred at random times and locations. Reserve capacity was added to the system in accordance with the reserve margin framework, providing a "cushion" for system operators to maintain electric service, even when facing higher-than-expected load or generator outages. The amount of excess (reserve) capacity needed for each system was determined by observing the attributes of the generation mix.

At the turn of the 21st century, the electric system began integrating renewable resources at different speeds and trajectories throughout the country. The variable nature of these resources created a need to explore different methods to better assess the potential output so that system planners and operators could respond accordingly. Several regions also began pushing for equal access to the transmission system and ultimately enabled wholesale competition with the first independent grid operators (IRC, 2023). The larger systems

1 The probabilistic analyses included Loss of Load Hours (LOLH), Loss of Load Probability (LOLP), Loss of Load Events (LOLE), or Expected Unserved Energy (EUE). Wilson & Peterson, 2011. By 1947, Giuseppe Calabrese, an assistant engineer at the Consolidated Edison Company of New York (today known primarily as ConEd), had written a technical paper entitled, "Generating Reserve Capacity Determined by the Probability Method." The criterion of limiting outage events to one every ten years (1-in-10 LOLE) can be found beginning in the 1950s and continues to be widely used today. While some consider criteria like the 1-in-10 LOLE to be outdated and uneconomic, studies like those of Giuseppe Calabrese constitute the first steps towards comprehensive resource adequacy standards in the United States (Carden & Wintermantel, 2013).

allowed for a pooling of resources, consolidated planning processes across multiple entities, and a reduction of excess reserve capacity. In recent decades, the electric system faced more significant impacts from extreme weather events that carry a greater threat of causing correlated events, common mode outages, and fuel supply interruptions (ESIG 2023).[2] On the customer side, energy efficiency and demand-side management have reduced demand growth with technological advancements including efficient appliances and internet-connected devices. However, load profiles have also grown in complexity and are increasingly difficult to forecast, due to increasing installations of customer-owned resources and equipment (e.g., rooftop solar), electric vehicle chargers, and behind-the-meter battery storage, as well as the changes to distribution system needs with increased remote work (higher residential demand and lower commercial demand) resulting from the COVID-19 pandemic. Reliability risks are also increasingly viewed as concentrated not only in summer months, but during the winter, calling into question the long-history of addressing summer peak loads in most parts of the United States (ESIG, 2023). Finally, planning for enough resources to meet the typical summer afternoon peak is no longer adequate, as other periods of high demand and energy-limited resources are creating additional periods of tighter operating conditions for system operators.

These trends have accelerated during the past two decades, with the proliferation of variability and uncertainty on both the supply and demand sides of the system. Despite the relatively rapid rate of these system changes, the purpose of resource adequacy – to ensure there are enough resources available on the system to meet future load, while accounting for uncertainty in both generation (outages) and load (forecast uncertainty) – remains unchanged and especially important as society's reliance on electricity continues to increase. Some reforms to existing resource adequacy approaches are needed, along with new tools that are commensurate with the changing nature of the system. System planners and utility regulators throughout the country face particular challenges in maintaining reliable systems with the appropriate combination of resources that are capable of serving customer demand at all times. More advanced resource adequacy approaches and supplemental analysis can inform state utility regulators as they deliberate on proposed utility resource decisions.

Additional Information on the History and Purpose of Resource Adequacy

- *Electric Regulation in the US: A Guide (Second Edition)* – Regulatory Assistance Project (Link)
- *The History of the North American Electric Reliability Corporation* – North American Electric Reliability Corporation (Link)
- *Electricity Explained: How Electricity Is Delivered to Consumers* – U.S. Department of Energy (Link)
- *Reliability Primer* – Federal Energy Regulatory Commission (Link)
- *Resource Adequacy Primer for State Regulators* – National Association of Regulatory Utility Commissioners (Link)

2 Common-mode outages can occur when underlying failures or common causes lead to multiple units going on outage simultaneously.

II. Regulatory Oversight of Electric Reliability

Regulation of the grid has evolved over the past 140 years, with oversight introduced at the federal, state, and local levels to advance a common objective of maintaining a reliable, safe, and affordable electric system. A reliable power grid requires ongoing coordination, collaboration, and oversight between users, owners, and operators—particularly amidst an ongoing transformation in the generation mix. Independent system operators (ISOs), regional transmission organizations (RTOs), and utility control areas or balancing authorities (BAs) are the primary entities charged with ensuring adequate capacity of generation and transmission to meet electricity demand. Electric utilities operate within these areas, in most cases as natural monopolies and are regulated accordingly. Interstate transmission, wholesale power markets, and other networks where interstate commerce is involved, are generally federally regulated, while utility retail rates, distribution services, and facility siting efforts are overseen by state or local utility regulators.[3] This section describes the various authorities and other participants that craft or implement resource adequacy at the federal, regional, state, and local levels. While there are other actors involved in electric regulation, this section focuses on those directly involved in maintaining system reliability.

Federal Energy Regulatory Commission (FERC)

The U.S. Department of Energy is the federal agency that is tasked primarily with establishing and implementing federal energy policies. However, the Federal Energy Regulatory Commission (FERC) is responsible for regulating the more technical aspects of the electricity industry, including wholesale market design, reliability of the bulk electric system, and in some cases, resource adequacy. FERC is an independent federal agency that regulates, among other things, the interstate transmission of electricity and wholesale sales of electricity. Additionally, FERC is responsible for "the reliability of the high voltage interstate transmission system through mandatory reliability standards (FERC, 2022)." In 1999, FERC approved the creation of five ISOs in Orders 888 and 889. FERC subsequently provided additional refinements in Order 2000, including voluntary standards for Regional Transmission Organizations (RTOs). The ISO/RTO paradigm arguably improved system reliability byfostering operational and planning coordination across control areas.

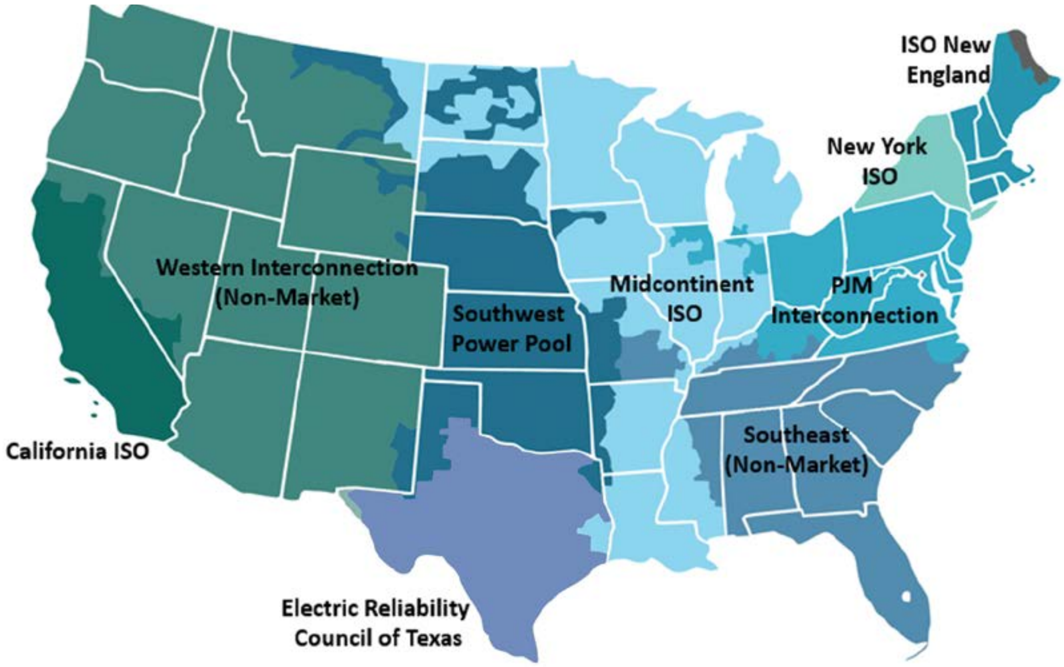
As of 2023, over two-thirds of the United States are served by seven ISO/RTOs that oversee energy markets (and capacity markets in some cases) and provide nondiscriminatory access to transmission (IRC, 2023). ISOs/RTOs are also responsible for planning, operating, and dispatching energy within their footprint. In all ISO/RTOs, these activities are implemented through the administration of a wholesale electricity market with parameters captured in a tariff that is submitted for FERC approval. ISO/RTOs also provide reliability planning for bulk electricity system components and oversee short-term reliability. The following map in **Figure 1** illustrates the general operational boundaries for ISO/RTO areas throughout the United States.

Federal Power Marketing Administration (PMA)

Four Power Marketing Administrations (PMAs) operate as federal agencies within the Department of Energy, responsible for marketing large hydropower and other resources that are operated by other federal agencies. The PMAs market electricity that is generated from some of the nation's largest river basins, including the Columbia and Colorado. Each PMA functions as a balancing authority for their respective regions. Three of the four PMAs also construct and own transmission lines; SEPA does not. PMAs are self-funded, nonprofit entities selling hydroelectric power and/or providing transmission services in 34 states (**Figure 2**).

3 Most state commissions regulate low-voltage retail distribution facilities, quality of service standards, and the prices and terms of service for electricity provided by investor-owned utilities. Cooperative and municipal utilities are regulated by commissions in some states, but commonly regulated by local government bodies or elected utility boards.

Figure 1: ISO/ RTO and Non-Market Area Map (FERC, 2022)



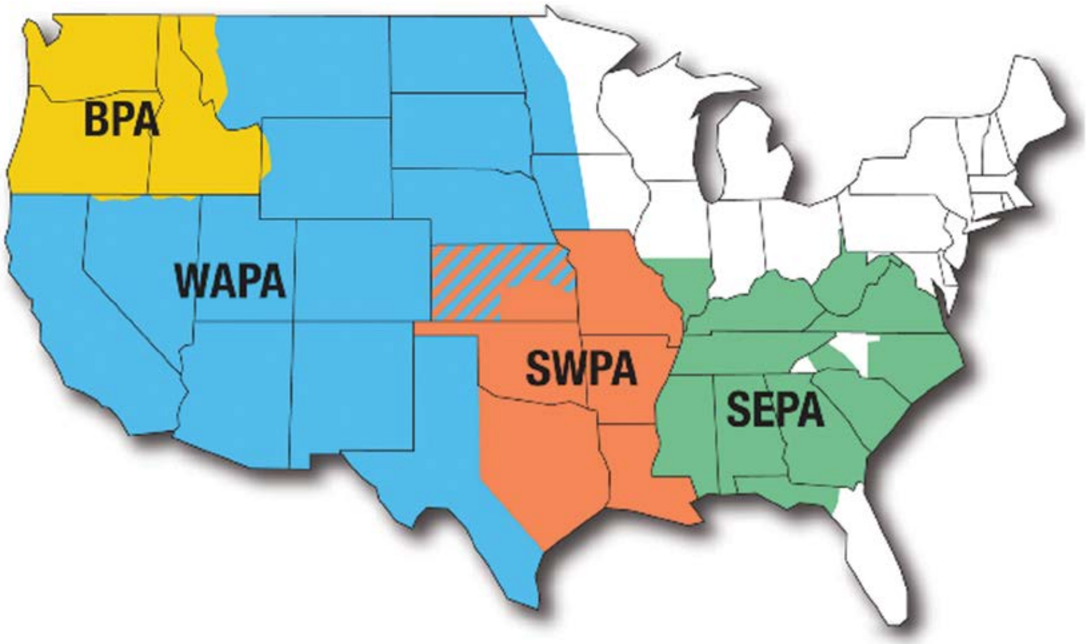
ISO/RTO	States with Participating Utilities
California ISO	California, Nevada
Electric Reliability Council of Texas (ERCOT)	Texas
ISO-New England (ISO-NE)	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
Midcontinent ISO (MISO)	Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, Wisconsin
New York ISO (NYISO)	New York
PJM Interconnection	Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia
Southwest Power Pool (SPP)	Arkansas, Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming

North American Electric Reliability Corporation (NERC)

The 2003 Northeast Blackout highlighted a need for additional oversight related to electric grid reliability. The Energy Policy Act of 2005 expanded FERC's role and jurisdiction under the Federal Power Act (FPA) by adding Section 215, which granted FERC the authority to certify a non-governmental "electric reliability organization" (ERO) (Nevius, 2020).[4] In 2006, the North American Electric Reliability Corporation (NERC) was approved as the

4 Reliability standards were introduced in the mid-1990s, but were not enforceable until 2007.

Figure 2: Power Marketing Administration Map (WAPA, 2015)



PMA	Description
Bonneville Power Administration (BPA):	The BPA is responsible for marketing wholesale electrical power from 31 federal hydroelectric dams in the Northwest, one nonfederal nuclear plant and several small nonfederal power plants. Three of the nation's largest five hydroelectric facilities are located on the Columbia River in BPA's operating territory (EIA, 2013). The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. The nonfederal nuclear plant, Columbia Generating Station, is owned and operated by Energy Northwest, a joint operating agency of the state of Washington. BPA also operates and maintains approximately 15,000 miles of high-voltage transmission in its service territory, covering the Columbia River basis in Washington, Oregon, and small pieces of western Montana and western Wyoming. BPA sells its electric power services to 142 customers that primarily comprise of electric cooperatives, municipalities, and public utility districts (BPA, 2022).
Western Area Power Administration (WAPA)	The WAPA is responsible for marketing wholesale electricity from multi-use water projects for a 15-state region of the central and western U.S., including the Hoover Dam (the nation's sixth largest hydroelectric power facility). WAPA operates a transmission system totaling more than 17,000 circuit miles, which carries electricity from 57 hydropower plants, totaling an installed capacity of over 10,000 MW. WAPA sells power primarily to preference customers, including federal and state agencies, cities and towns, rural electric cooperatives, public utility districts, irrigation districts and Native American tribes, which provide retail electric service to millions of consumers in the West.
Southeastern Power Administration (SEPA)	The SEPA is responsible for marketing electric power and energy generated at reservoirs operated by the U.S. Army Corps of Engineers. Electricity generated is marketed by SEPA to more than 491 customers (electric cooperatives and other public bodies) in Alabama, the Florida panhandle, Georgia, Kentucky, Mississippi, North and South Carolina, Tennessee, Virginia, and West Virginia (SEPA 2022).
Southwestern Power Administration (SWPA)	The SWPA serves over 5.6 million kilowatt-hours of energy from interconnected federal hydropower projects to approximately 10-million end users served by the municipalities, electric cooperatives, and military installations in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas.

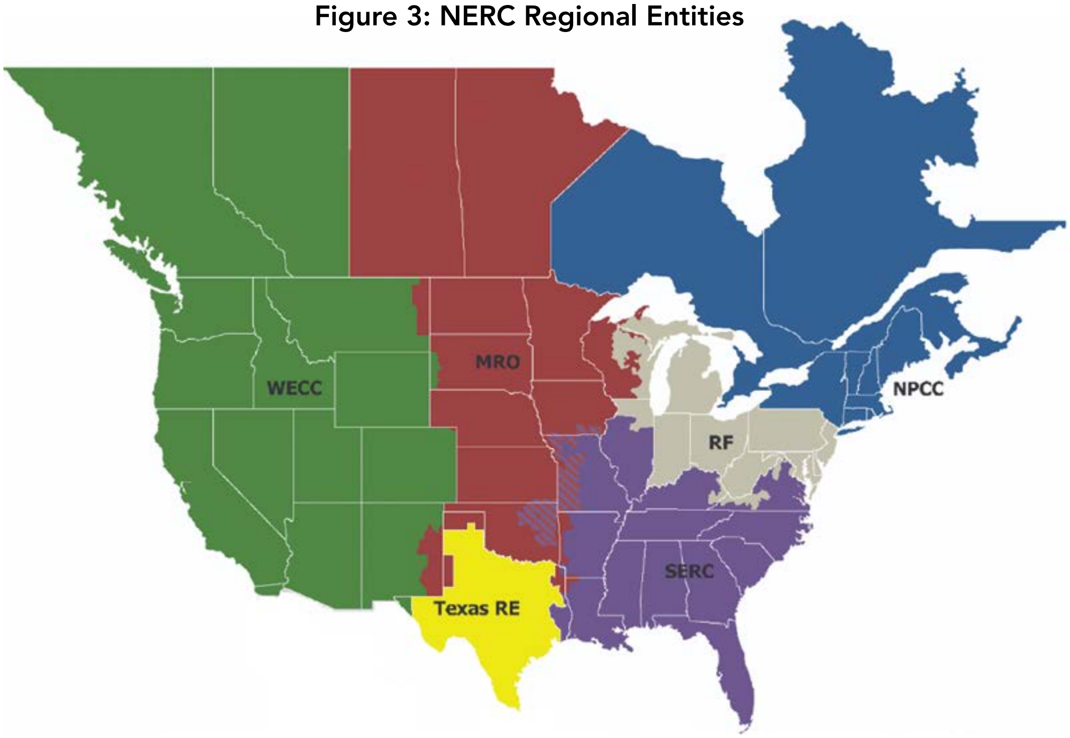
ERO in the United States, with similar authority granted by Canadian provinces. NERC developed an initial set of mandatory Reliability Standards, which FERC approved in June 2007. The newly-formed entity was charged with an ongoing responsibility of developing and enforcing mandatory Reliability Standards (Nevius, 2020).

NERC is a not-for-profit international regulatory authority charged with assuring the effective and efficient reduction of risks to the reliability and security of the North American grid (NERC, 2023). NERC develops and enforces reliability standards, annually publishes seasonal and long-term reliability assessments, monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel.

Although only NERC is authorized to develop new reliability standards with input from the industry, FERC provides a review to ensure they are "just, reasonable, not unduly discriminatory or preferential, and in the public interest." FERC must approve Reliability Standards before they become enforceable in the United States. Since the establishment of NERC as the ERO, FERC has approved over 100 mandatory standards that address many components of system planning and operation aimed at maintaining bulk power system reliability.[5] Additionally, FERC has promulgated regulations defining the structure of the country's reliability program, issued directives, ordered standards to be developed, and reviewed thousands of compliance and enforcement actions submitted by NERC.

As the ERO, NERC oversees six Regional Entities (**Figure 3**), referred to as the ERO Enterprise, that serve the needs of their regional constituents and ensure adherence to NERC's Reliability Standards.

Figure 3: NERC Regional Entities



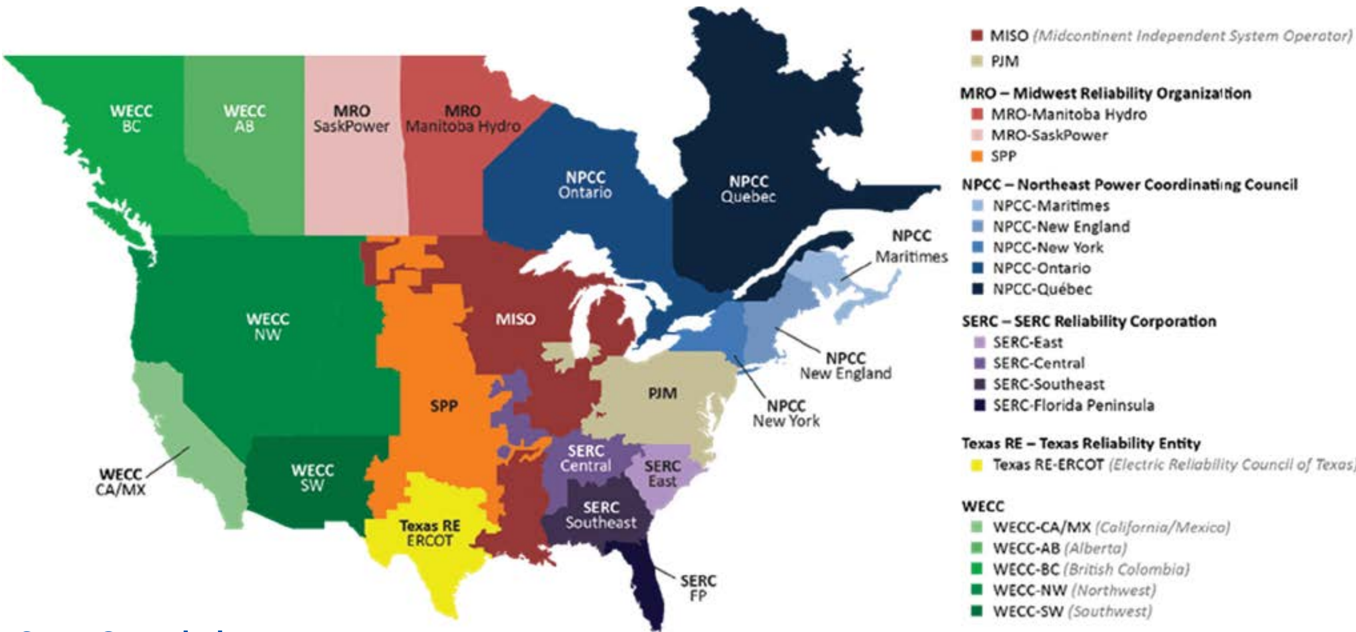
Midwest Reliability Organization (MRO)	SERC Reliability Corporation (SERC)
Northeast Power Coordinating Council (NPCC)	Texas Reliability Entity, Inc. (Texas RE)
ReliabilityFirst (RF)	Western Electricity Coordinating Council (WECC)

5 The NERC Standards Committee includes representation from investor-owned, municipal, and cooperative utilities, Federal Power Marketing Administrations, transmission-dependent utilities, merchant electricity generators, electricity marketers, large and small end-use electricity consumers, ISO/RTOs, NERC Regional Entities, and federal government representatives.

While NERC and the Regional Entities play different roles in delivering ERO Enterprise programs, these roles are equally important and complementary, enabling the ERO Enterprise to work as one coordinated organization—effectively, efficiently, and collaboratively (NERC, 2023).

NERC also evaluates Bulk Electric System reliability through annual seasonal and long-term assessments, as well as a biennial probabilistic assessment, providing an independent examination of the projected resource adequacy metrics and associated risks to the North American bulk power system. NERC provides these assessments and evaluations based on assessment areas (**Figure 4**), which align with the existing footprints of ISO/RTOs in parts of the country where they exist, or control areas or planning authority boundaries in regions without established ISO/RTOs.

Figure 4: NERC Assessment Areas (NERC, 2023)



State Commissions

State utility commissions are created by individual state governments to regulate monopoly utilities that are awarded a franchise to serve customers within a defined territory. State utility commissions are quasi-judicial agencies that were created to, among other things, oversee the rates charged by electric, gas and water utilities, which are essentially government-sanctioned monopolies. Most commissioners are appointed by the governor and approved by the state senate. Commissioners are either elected or appointed, pursuant to state law. Of the 54 regulatory commissions (including U.S. territories), members are appointed in 39 and elected (in some form) in 15 (Hlinka, 2021).

Since electric utilities provide essential services that are "affected with the public interest," the infrastructure, technological, and economic structure of the industry creates conditions where a single provider is the most efficient and cost-effective paradigm to serve customers (Lazar, 2016). The single provider model (essentially a natural monopoly) inherently limits competition, so government intervention in the form of independent regulatory oversight through state utility commissions aims to achieve public benefits in the absence of a competitive market (Lazar, 2016). Moreover, commissions aim to prevent monopolized service providers from leveraging opportunities to restrict output or otherwise increase prices to levels that are unjust or unreasonable (Lazar, 2016). Additionally, state utility commissions generally conduct the following functions in their respective states through similar procedures:

- Determine the revenue requirement (e.g., the amount of revenue the utility may earn);
- Allocate costs (revenue burdens) among customer classes;

- Design price structures and price levels that will collect the allowed revenues, while providing appropriate price signals to customers;
- Set service quality standards and consumer protection requirements;
- Oversee the financial responsibilities of the utility, including reviewing and approving utility capital investments and long-term planning;
- Serve as the arbiter of disputes between consumers and the utility; and
- Implement state energy policies, as directed by the legislature or governor.

Perhaps the most significant responsibility of state utility regulators involves the review of utility resource plans and corresponding rates, deliberated in a way that is reflective of the public interest. Commissions are generally responsible for regulating the electric utilities that operate within their geographic territory, regulating retail electric rates and utility services for customers, overseeing the safety and reliability of the associated distribution system, including distributed energy resources (DERs), and in some states, siting electric facilities. FERC has expanded its wholesale market jurisdiction over some aspects of the distribution system, including the market participation of distributed energy and storage resources. Additional information on these developments is provided in FERC Order 2222.

While utilities are responsible for resource acquisition and maintaining resource adequacy, state legislatures and executives generally determine resource policy, and state utility commissions are responsible for determining resource adequacy and the prudence of utility resource acquisition. However, some states choose to align their requirements with those established by RTOs or other regional authorities. Many state commissions also hold siting authority over generation and/or transmission facilities within the utility service territory that they regulate (Smith, 2021).

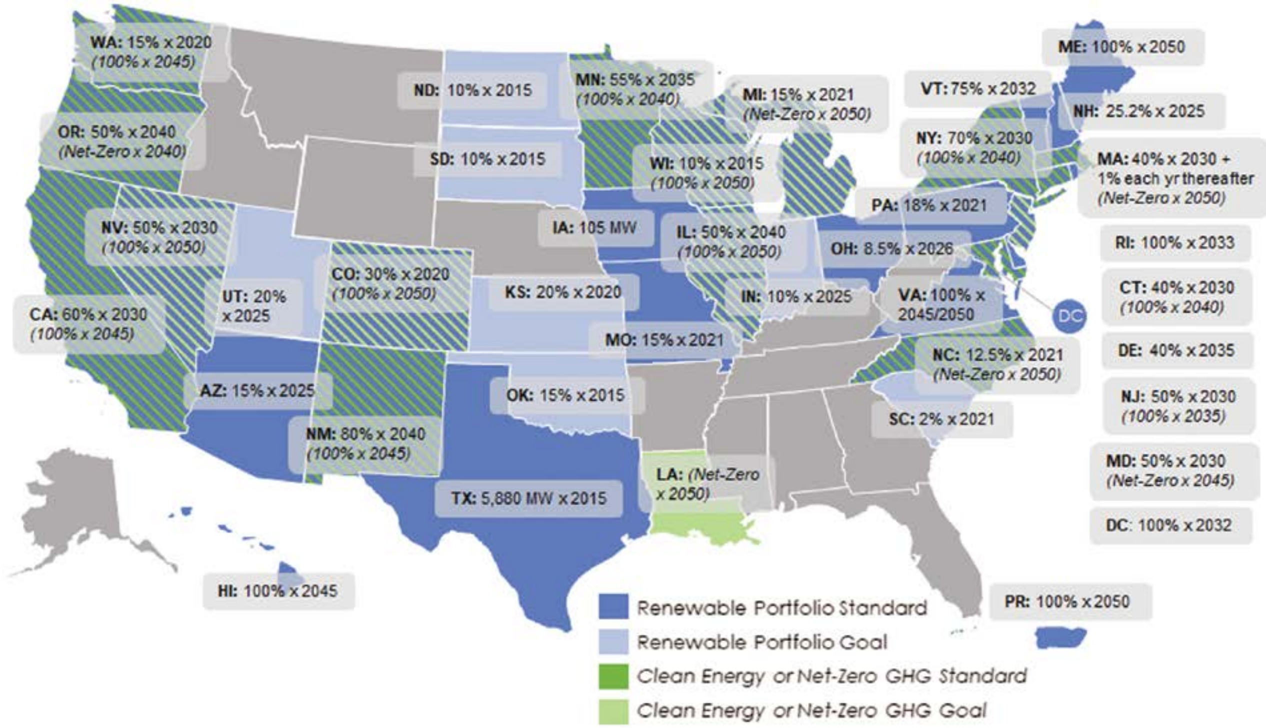
As commissions conduct their regulatory oversight, consideration is given to the potential short-and long-term reliability impacts in their jurisdiction from adding new resources or taking existing resources out of service. Finally, they often oversee utility plans for vegetation management, facility inspections, and maintenance of assets, which often must also comply with NERC Reliability Standards.

State Legislatures

Legislative bodies throughout the country can exercise authority over the generation within their state's territory by developing and implementing policies that promote or limit generation resources, including those that establish renewable portfolio or clean energy standards that specify which resources qualify to meet the standards. Legislatures can also specify the priority or order by which state commissions must consider various resource types when evaluating resource or procurement plans. As of May 2023, 20 states have set clean or renewable energy standards or goals to reach net-zero emissions by 2050 (**Figure 5**) (NC State, 2023).

Many state legislatures have also introduced and codified bans on the new construction of certain generation types. As of September 2023, twelve states currently have legislated some level of restriction on the construction of new nuclear power facilities, including California, Connecticut, Hawaii, Illinois, Maine, Massachusetts, Minnesota, New Jersey, New York, Oregon, Rhode Island and Vermont (NCSL, 2023). Some state legislatures have also introduced policies aimed at preventing certain plants from closing. For example, California's legislature introduced a bill in 2023 that was ultimately signed by the governor to extend the operation of Diablo Canyon Nuclear Power Plant to 2030, five years beyond its planned closure in 2025 (CA Office of the Governor, 2023). In New Jersey, the governor signed legislative initiatives in 2018 to advance the state's clean energy goals, including subsidies designed to ensure continued operation of three nuclearpower plants (Reuters, 2018).

Figure 5: State Renewable Portfolio and Clean Energy Standards/Goals (NC State University, 2023)



State Energy Offices

Energy offices or divisions in each state vary significantly in size, authority, designated responsibilities, funding, and interaction with other state regulatory bodies. In addition to state funding, many state energy offices also receive direct or supplemental funding from federal agencies (e.g., the Department of Energy). State energy offices also have varying levels of involvement in resource adequacy processes. The California Energy Commission (CEC), for example, is heavily involved with the implementation of clean energy initiatives and develops the load forecasts for load-serving entities. The CEC's load forecast is a critical input for resource adequacy assessments, used by the California Public Utility Commission and California Independent System Operator (CAISO) to inform resource decisions and integrated resource planning efforts. Additionally, the staff of over 600 CEC employees work to develop public policy recommendations and provide analyses for the state decision-makers to, among other things, improve energy reliability. Alternatively, the Alaska Energy Authority (AEA) has a narrower mission to "reduce the cost of energy in Alaska." These examples demonstrate the wide degree of authority related to reliability and resource adequacy for state energy offices across the country.

Additional Information on the History and Purpose of Resource Adequacy

- *Electric Regulation in the US: A Guide (Second Addition)* – Regulatory Assistance Project (Link)
- *Reliability Primer* – Federal Energy Regulatory Commission (Link)
- *NERC U.S. Reliability Standards* – North American Electric Reliability Corporation (Link)
- *State and Territory Energy Offices* – National Association of State Energy Offices (Link)
- *National Conference of State Legislatures Resources* – National Conference of State Legislatures (Link)
- *Resource Adequacy Primer for State Regulators* – National Association of Regulatory Utility Commissioners (Link)
- Map with Information of Each Regulatory Commission – National Association of Regulatory Utility Commissioners (Link)

III. Foundational Concepts

The resource adequacy framework that is still largely used today, was developed almost a century ago. The concept of a reliable system was built on the bedrock of a reliability standard that measured whether a power system had enough resources to serve load. Before identifying the existing limitations within this standard (Section IV), it is important to recognize why certain concepts, like the reserve margin, have remained the primary resource adequacy metric, despite relatively rapid transformation of the resources on the system.

Planning Standards

The concept of resource adequacy formally emerged during the 1940s, with the application of probabilistic analysis to establish a foundational planning standard for the electric grid that was aimed at maintaining adequate capacity.[6] This planning standard was based on the metric "Loss of Load Expectation" (LOLE), which quantifies the expected adequacy of a system, typically using a criterion of one day of outage during a 10-year period (1-day-in-10-year LOLE). Alternative statistical metrics are commonly used in reliability planning to determine the size, duration, and frequency of event interruptions (**Table 1**):

Table 1: Statistical Reliability Metrics (CPUC, 2022)

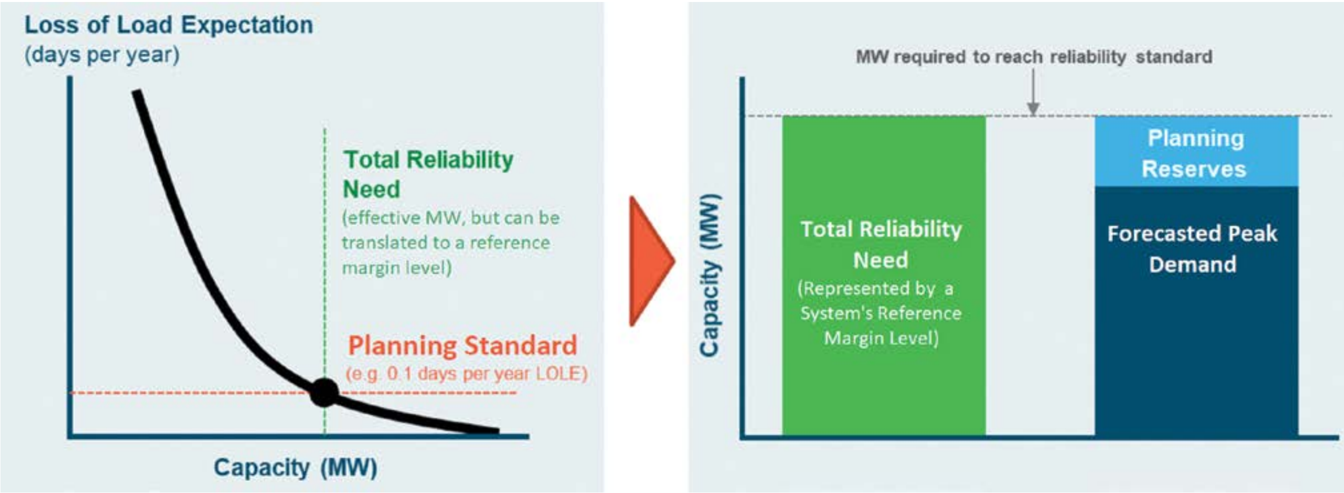
Metric	Unit(s)	Definition
Loss of Load Expectation (LOLE)	days/year	Average number of days per year in which unserved energy occurs due to system demand exceeding available generating capacity
Expected Unserved Energy (EUE)	MWh/year	Average total quantity of unserved energy (MWh) over a year due to system demand exceeding available generating capacity
Loss of Load Probability (LOLP)	%	Probability of system demand exceeding available generating capacity during a given time period
Loss of Load Hours (LOLH)	hours/year	Average number of hours per year with loss of load due to system demand exceeding available generating capacity
Loss of Load Events (LOLEV)	events/years	Average number of loss of load events per year, of any duration or magnitude, due to system demand exceeding available generating capacity
Value of Lost Load (VOLL)	$/MWh	Quantifies the loss that is incurred by customers in the event of electricity service interruption.
Cost of New Entry (CONE)	$*(MW*yr)-1	Varying industry methods used to indicate the current, annualized, capital cost of constructing a power plant (MISO, 2022).

While these metrics are all useful for system planning, the LOLE became—and remains today—the primary driver for determining an area's reference margin level (**Figure 6**), often referred to as a "reserve margin target," "planning reserve margin," or "planning target."

The reference margin level, represented as a percentage, serves as a minimum threshold for resources needed to serve projected demand, including some buffer (reserve capacity) for addressing potential resource

6 The probabilistic analyses include Loss of Load Hours (LOLH), Loss of Load Probability (LOLP), Loss of Load Events (LOLE), or Expected Unserved Energy (EUE) (Wilson & Peterson, 2011). By 1947, Giuseppe Calabrese, an assistant engineer at the Consolidated Edison Company of New York (today known primarily as ConEd), had written a technical paper entitled, "Generating Reserve Capacity Determined by the Probability Method." The criterion of limiting outage events to one every ten years (1-in-10 LOLE) can be found beginning in the 1950s and continues to be widely used today.

Figure 6: Loss of Load Expectation vs. Reference Margin Level (CPUC, 2022)



limitations (e.g., generator and transmission outages) and/or higher than forecasted demand.[7] Similarly, the concept of resource adequacy serves as "a measure of the ability of a power system to meet the electric power and energy requirements of its customers within acceptable technical limits, taking into account scheduled and unscheduled outages of system components (CIGRE, 2018)." NERC further identifies resource adequacyas one of two key components for maintaining system reliability (NERC, 2007). NERC defines adequacy as the ability of the electric system to supply the aggregate requirements of electricity consumers. Operating reliability (previously termed 'security') is the ability of the system to withstand sudden disturbances. Sufficientgeneration resources procured over the long-term (adequacy) ensures that grid operations will be reliable inthe short-term (operating reliability) (Kelli, 2022).

The calculated LOLE is the primary and historically most common metric for determining a reference margin level. While there is no single reserve requirement, various authorities throughout the country may select a target level to achieve what they determine to be an acceptable level of reliability. Additional factors in making this determination may include costs, resource portfolio, system fragility (frequency of outages), the robustness of the transmission system, types of loads served, and other considerations. For example, systems that include predominantly hydro-powered resources (e.g., Manitoba and Quebec) tend to select a lower reference margin level (10-12%), with consideration for lower forced-outage rates. Alternatively, most areas in the United States maintain reference margin levels between 13-19%. The basic assumption for this probabilistic analysis is that units will fail randomly, at different times and locations throughout a system (i.e., common-mode failures are not generally modeled in probabilistic studies). **Table 2** includes the 2023 reference margin levels, as determined by various authorities throughout the country and reported by NERC on an assessment area-basis.[8] Many of these entities are currently examining their planning criteria and considering modifications due to recent extreme weather events, which have highlighted potential limitations in the foundational resource adequacy assumptions relied upon in reliability assessments. These limitations are examined in the first part of Section IV.

The size of the area and diversity of resources can also impact how planners determine development and application of resource adequacy approach. Pooling resources across a larger region can improve load and resource diversity and achieve cost savings through increased market competition, broader risk sharing, and reliability improvements. For example, extreme weather that impacts resource availability in one part of a large region can access available resources in non-effected parts of the region.

7 Probabilistic analysis used to inform a reference margin level may incorporate basic deliverability assumptions (i.e., using modeling assumptions that include identified transmission constraints or outages).

8 An Assessment Area is a single planning authority, or a group of planning authorities (as defined by NERC).

Table 2: U.S. Reference Margin Levels

NERC Assessment Area	Reference Margin Level[9]	Method	Regulatory Entity or Authority
CAISO	15% (2022); 16% (2023); 17% (2024)	0.1 day/year LOLE; established annually	California Public Utilities Commission
MISO	15.9% (Summer) 25.8% (Fall) 41.2% (Winter) 39.3% (Spring)	0.1 day/year LOLE; established annually (varies by season)[10]	MISO
ISO-New England	13.4-13.6%	0.1 day/year LOLE	ISO-New England; NPCC criterion
New York ISO	15% (20% IRM)[11]	0.1 day/year LOLE	New York State Reliability Council; NPCC criterion
PJM	14.4-14.8%	0.1 day/year LOLE	Reviewed by PJM Board of Managers[12]
SERC-Central	15%	0.1 day/year LOLE (*Varies by season*)	Member Utilities
SERC-East	15%	0.1 day/year LOLE (*Varies by season*)	Member Utilities
SERC-Florida Peninsula	15%	0.1 day/year LOLE (*Varies by season*)	Florida Public Service Commission
SERC-Southeast	15%	0.1 day/year LOLE (*Varies by season*)	Member Utilities
SPP	16%	0.1 day/year LOLE; studied on biennial basis	SPP RTO Staff and Stakeholders
Texas RE-ERCOT	13.75%	0.1 day/Year LOLE; adjusted for non-modeled market considerations	ERCOT Board of Directors
WECC-Northwest	13.5-15.2%	0.1 day/Year LOLE	WECC
WECC-Southwest	10.7-12.4%[13]	Based on LOLP ≤ 0.02% threshold, as determined by WECC	WECC

9 Levels are based on Installed Capacity (ICAP).

10 Beginning in 2023, MISO established four seasonal reference margin levels.

11 The 2023-2024 IRM, established by the NYSRC, represents the amount of installed capacity that must exist in the New York Control Area (NYCA) to ensure that the applicable resource adequacy reliability criteria are met.

12 Also enforced by NERC-RF Reliability Standard BAL-502-RFC-02.

13 Individual reference margin levels (Planning Reserve Margins) for Electric Providers in New Mexico and Arizona range from 10.1% to 18%.

Planning Reserve Margin

The reference margin levels for each assessment area function serve as a marker for comparison with a second metric, the planning reserve margin (PRM). The PRM is a deterministic output of an equation with two inputs: forecasted load (i.e., demand) and resources (i.e., supply). Generally, a reserve margin is calculated as the percentage by which the projected resources available during the peak exceeds the forecasted peak demand. This deterministic metric can be demonstrated using basic assumptions and inputs. In the following example, the system is modeled with the following assumptions:

- **Total installed capacity: 35,000 MW** *(includes total capacity, both operable and inoperable)*
- **Effective capacity: 25,000 MW** *(expected capacity to be available during the peak period for the upcoming season, with capacity accreditation approaches that likely vary by resource type)*
- **Forecasted Peak Load: 20,000 MW** *(representing the highest probability of peak demand when observing a normal distributed load forecast; reducing for projected controllable and dispatchable demand response)*.[14]

The basic projected resources and forecasted load inputs will be calculated in the PRM as follows:

$$\text{Planning Reserve Margin} = \frac{\text{Effective Capacity - Forecasted Peak Load}}{\text{Forecasted Peak Load}} = \frac{25{,}000 - 20{,}000}{20{,}000} = 25\%$$

The PRM analysis examines the summer and winter seasons, when demand for electricity is highest, compared to the spring and fall, often referred to as "shoulder seasons."[15] An electric system or balancing area is deemedto be "resource adequate" during the study period if the planning reserve margin remains above the reference margin level. Specifically, if the 15% reference margin level (target) is based strictly on a 1-day-in-10 Loss ofLoad Expectation criterion, the area is projected to exceed that planning standard by 10% with a 25% PRM,based on the forecasted load and projected effective capacity when the assessment was conducted.

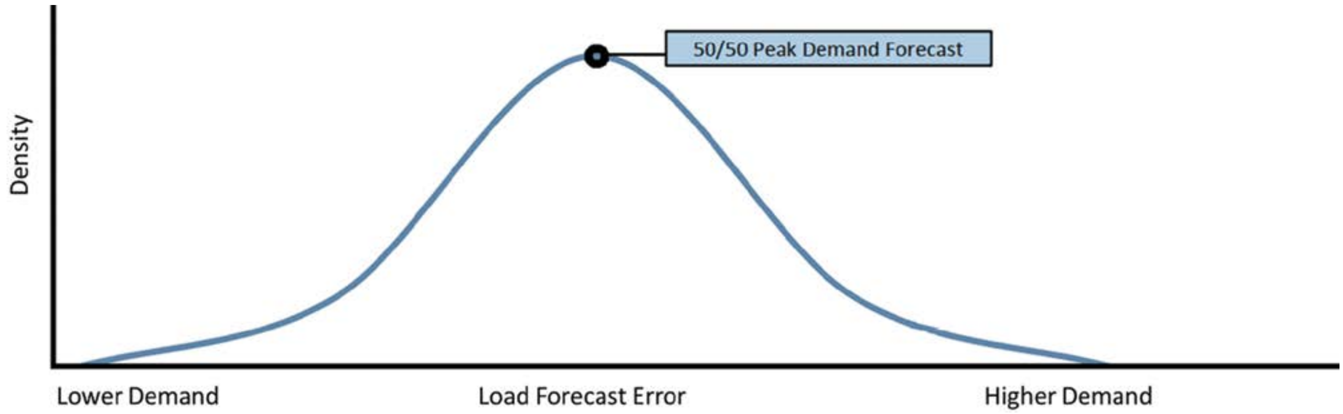
While the PRM relies on only two inputs, forecasted load and resources output during the peak load window have become increasingly complex during the past fifty years. Peak load or "peak load window" is commonly forecasted using a "50/50" approach, which assumes there is a 50% probability that actual demand will be either higher or lower than projected (**Figure 7**). Load forecasting methodologies vary in sophistication and number of data inputs.

Early forecasting methods relied largely on economic growth projections and basic long-term weather models, while daily load profiles were predictable. Today's load forecasters face a variation in daily loads, unpredictable customer behavior (e.g., new technologies like behind-the-meter EV charging and large-scale battery storage), varying economic impacts (e.g., the correlation between economic growth and electricity usage), and highly variable loads due to distributed generation—primarily rooftop PV. Additionally, many parts of the country are anticipated to experience overall load growth over the next decade driven by sharply increasing data center load, electrification of heating and cooling for buildings, and electric vehicle charging). Advanced load forecasting practices attempt to incorporate many of these uncertainties, estimating demand-side impacts, including energy efficiency, customer response to time-of-use and peak rates, and load impacts from behind-the-meter resources (e.g., rooftop PV). The forecasted net peak load is the most common input for the PRM

14 For consistency, NERC counts all controllable and dispatchable demand response as a load-modifying resource. Other system studies consider demand response and other demand-side resources to be counted as resource instead of a load-modifier). In market areas, demand-side resources can also participate in the capacity market. When demand response is counted as a resource, the corresponding PRM will be slightly higher than when demand response is counted as a load-modifier.

15 NERC releases summer and winter seasonal reliability assessments, as well as their annual long-term reliability assessment that examines projected summer and winter margins during a 10-year period. Other areas (e.g., CAISO) release seasonal assessments that include reserve margin analysis for each month.

Figure 7: 50/50 Peak Load Forecast



calculation, which is the gross load forecast reduced by projected energy efficiency and controllable and dispatchable demand response projected to be available during the peak hour (NERC, 2022).

PRM Forecasted Load = Total peak load[16] - Controllable and Dispatchable Demand Response

Projecting resource availability and output (supply) during the peak involves complex inputs that are difficult to accurately project in a long-term study, including weather conditions, ambient temperature, fuel availability, maintenance and forced outages (EPRI, 2022). System planners have developed several methods to project a resource's output. These "capacity accreditation" methods are commonly used by system planners when determining the resources category of the PRM.

Installed Capacity (ICAP)

The ICAP measures a resource's output (MW) using the installed capacity value, also known as the nameplate capacity.

Unforced Capacity (UCAP)

The UCAP measures a resource's output (MW) using the unforced (i.e., forced outage derate factor) capacity, accounting for forced outages. Specifically, a resource's UCAP is generally calculated as a function of both its ICAP and its Equivalent Forced Outage Rate Demand (EFORd). A resource's EFORd is generally used to determine its availability when examined independently (i.e., without consideration for other system impacts) (Carden, Dombrowsky, and Amitava, 2022). The UCAP is expressed as an equation:

UCAP = Nameplate MW x (1-EFORd %)[17]

In a simplified example, if a 100 MW gas turbine has a 3% forced outage rate, 97 MW will be credited towards the resource category of the planning reserve margin. The UCAP would be 97 MW.

Effective Load Carrying Capability (ELCC)

Accurately projecting the contribution of any given resource to meeting resource adequacy needs requires accounting for a variety of factors, including how to project system performance, the contributions of similar energy-limited resources, and the system's exposure to events that may lead to common-mode failures. The ELCC approach has been a commonly used approach to project the output of variable (wind and solar) and energy-limited (storage and load flexibility) resources, particularly during high-risk periods, including the peak load window. The projected ELCC-based output of a resource is determined through the examination of a set of hours, identifying various probabilities of loss-of-load events. Moreover, the ELCC is a probabilistic metric

16 Load forecasting approaches throughout the country account for impacts energy efficiency and other customer-side impacts. Some systems use a coincident peak load forecast, while others use a noncoincident peak load forecast.

17 Equivalent Forced Outage Rate demand (EFORd) is a Strategic Energy Risk Valuation Model (SERVM) output characterizing class average forced outage rates using generator performance data. Source: CPUC.

that examines the addition of a resource based on the amount of load that can be added to a system, while maintaining the same level of system reliability (as measured by the LOLP and LOLE) (Denholm and Sioshansi, 2012). The ELCC is calculated in three steps (ESIG, 2022):

1. The system is modeled to the desired reliability criterion (e.g., 1-day-in-10-year LOLE)
2. The examined resource is added to the system, thus reducing the LOLE and making the system more reliable.
3. A fixed amount of load is added to the model (across all hours) until the original LOLE criterion is reached.

The ELCC is essentially the difference between the amount of load added to a system, relative to the available capacity for a given resource. The ELCC analysis is commonly used to calculate a resource's contribution to the PRM and in relation to system demand during peak conditions, expressed as a percentage of its nameplate or maximum output.[18]

A resource's ELCC can be particularly useful for determining the expected performance in both market and non-market areas. There are two different methods for conducting an ELCC assessment of a resource: marginal or average accreditation. The average ELCC approach will generally result in less dramatic changes to the planning reserve margins (often instrumental in determining which system capacity needs), as more of the same resource class is added to a system's portfolio. This is because the average contribution of an entire resource class will diminish at a slower rate. The average accreditation technique is used to calculate ELCC for a combined class of resources to show the overall contribution of the resource type. The marginal approach used for estimating the incremental impacts of each resource in terms of their respective reliability contributions vary depending on when the resource is added to the system.

Assessing the ELCC of certain resources across a system can also be a useful approach for identifying the potential size, frequency, and duration of outages so that planners can determine the appropriate resource solutions, such as more transmission, generation, and/or demand-side management. Recognizing that all energy sources have different performance levels, and that no generation is perfectly reliable, capacity accreditation provides a more sophisticated approach than a capacity factor, forced outage rate, or deterministic expected output for the peak period.

In most regions, capacity accreditation techniques vary depending on the resource type. System planners often use a more simplistic approach, such as UCAP or ICAP for thermal resources (e.g., natural gas, nuclear, and coal). Wind, solar, run-of-river hydro, and battery storage resources often call for an ELCC approach that captures the complex dynamics resulting from increasing penetrations of these variable and energy limited resources. However, system planners in areas throughout the country are continuing to gravitate towards adopting capacity accreditations methods that are consistently applied to all resources. For example, the California Public Utilities Commission has transitioned from a mixed application of ICAP for thermal resources, and ELCC for variable resources, to a Perfect Capacity (PCAP) model, which consistently measures all resource contributions in an ELCC approach with additional adjustments to account for forced outage rates and additional portfolio effects in resource accreditation (CPUC, 2022).

System planners also account for capacity transfers (firm transmission import/exports) to or from neighboring systems, as well as any planned resource retirements or additions. Similar to the adjustments made to the PRM forecasted load (reducing for controllable and dispatchable demand response), the following equation demonstrates how resources are accounted for in the PRM analysis:

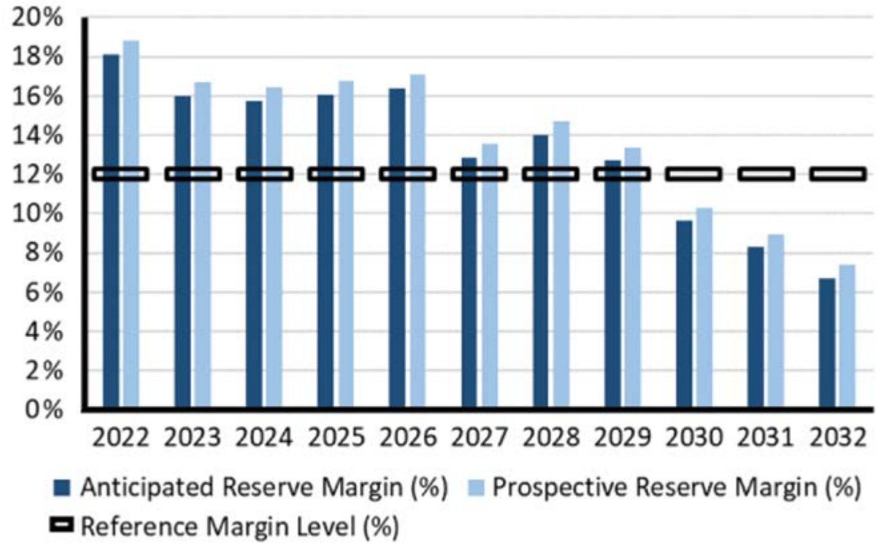
PRM Resources = Total System Resources[19] - Adjustments (UCAP, ICAP, ELCC) + Net Imports

18 More specifically, ELCC measures a resource's contribution to reliability as the incremental demand for power that can be satisfied by the addition of that resource to the system (Garver 1966)

19 Accounting for planned resources additions and/or retirements.

System operators throughout the country have developed different resource categories that are generally based on different levels of certainty. Many of these categories are informed by market data (e.g., forward capacity markets or auctions) or by combining individual IRPs from multiple utilities (i.e., load serving entities). NERC's Long-Term Reliability Assessments include two resource categories: Anticipated Resources and Prospective Resources. Anticipated Resources include existing capacity with firm transmission and account for planned resources or retirements that have higher levels of certainty. Prospective Resources include all Anticipated Resources, as well as less-certain existing resources (e.g., energy-limited or non-firm capacity), less-certain capacity retirements and planned resource additions, and non-firm capacity transfers.[20] Resource planning methods and processes for securing resources vary throughout the country. These categories help to create some level of consistency in collecting and presenting resource adequacy projections. These PRM categories are illustrated in the example below (**Figure 8**) from NERC's 2022 Long-Term Reliability Assessment.

Figure 8: Example of Reserve Margin Analysis (NERC, 2022)



NERC's 10-year assessment projects that Manitoba Hydro, a winter-peaking assessment area, will have adequate resources to serve the forecasted winter peak load through 2029. This assumes a normal (50/50) load forecast and a 12% reference margin level, as determined and periodically reviewed by the Manitoba Public Utilities Board. During the later years of the assessment period, both categories of the PRM fall below the reference margin level of 12%. It is common during the later years of a long-term assessment for the PRM to fall below the reference margin level, often resulting from continued load growth projections, combined with expiring firm transfer commitments, retiring generators, and uncertain plans for new resource additions. This can serve as a signal to resource planners, policy makers, utility regulators, and other industry participants that additional resources (e.g., generation capacity, demand response, and firm transfer capability) will be needed in the future.

Integrated Resource Planning

In the 1980s, as a result of volatility in the fuel market and concerns related to securing appropriate amounts of new generating capacity, several states began requiring regulated electric utilities to implement integrated resource planning (IRP). Utilities were directed to examine energy demand and supply and identify any risks that could prevent them from meeting long-term energy needs for their customers at reasonable costs (NARUC, 2013). In many IRP processes, the utility must conduct load forecasting, examining available resources on both

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20 Energy-limited resources are interconnected but unable to operate at full output (i.e., ICAP) continuously for specified periods of time, typically over four hours during a 24-hour period. Non-firm resources have non-firm transmission service that is provided on an as-available basis and is subject to interruption or curtailment (before curtailing firm transmission service)

the supply- and demand-side. An IRP is ultimately a planning tool that incorporates various other tools and metric to achieve particular goals (MEEA, 2011). IRPs are commonly developed by utilities and submitted for regulatory review every three-five years include considerations for maintaining system reliability.

Accounting for Retirements

In some cases, capacity retirements or unexpected delays in transmission construction are not captured in the resource categories of the PRM. Specifically, many at-risk or uneconomic plants often announce retirement plans with relatively short notice. Depending on the size and location of the plant, the system operator can conduct a separate study to examine potential system impacts and potentially designate the plant as "reliability must run" (RMR) in a market area. The arrangement to provide out-of-market capacity payments to keep the unit operational beyond its proposed retirement date must be approved by FERC or by the Public Utility Commission of Texas (ERCOT is not subject to FERC jurisdiction under sections 203, 205, or 206 of the Federal Power Act [FERC, 2022]), with consideration for other mitigating proposals, including transmission upgrades and/or alternative resources. The agreement, usually lasting less than a year, provides a negotiated, out-of-market payment for the power plant to recover its costs and earn a return. In certain arrangements, the resource can also receive additional revenues from energy sales. The process for negotiating RMR agreements varies considerably across different market areas and is an increasingly important tool for addressing potential short-term capacity or energy shortfalls.

Planning Horizons

The reserve margin metric serves as an important indicator of future system reliability. However, utility regulators may wish to carefully examine the underlying assumptions and familiarize themselves with the timing of the analysis. The PRM serves as a resource adequacy outlook, taken as a snapshot prior to the upcoming study period. Several factors can impact this outlook, highlighting the importance of supplementing this metric with other forms of analysis (to be explored in Part IV). It is also important to differentiate between longer term planning and operational planning metrics. While the reserve margin serves as the most common metric for seasonal and long-term planning, each area must always maintain sufficient operating reserves to address contingency events, as required by NERC Reliability Standard BAL-002-3 (NERC, 2018).[21] However, no NERC Reliability Standards dictate a minimum planning reserve margin or requirements to carry a minimum level of seasonal or long-term planning reserves.

Although low planning reserve margins indicate a higher risk for a system to experience periods of firm load shed, higher planning reserve margins and excess reserve capacity ahead of the season do not necessarily equate to guaranteed reliability, especially during extreme weather events. For example, ERCOT reported a 49.8% Anticipated Reserve Margin in NERC's 2020-2021 Winter Reliability Assessment, and subsequently experienced 20,000 MW of firm load shed over a four-day period (NERC, 2020). Similarly, NERC's 2020 Summer Reliability Assessment indicated a reserve margin of 20.9% for the California/Mexico subregion, well above the 13.7% target, but experience two load-shed events due to higher loads and unit outages. Ultimately, it is important to recognize that the reserve margin is developed with inputs that leverage resource availability projections at the time of analysis, combined with the highest probability of a load forecast distribution. Section IV further examines alternative approaches beyond the reserve margin that are designed to capture the potential for other operational risks and uncertainties.

The Changing Nature of the System

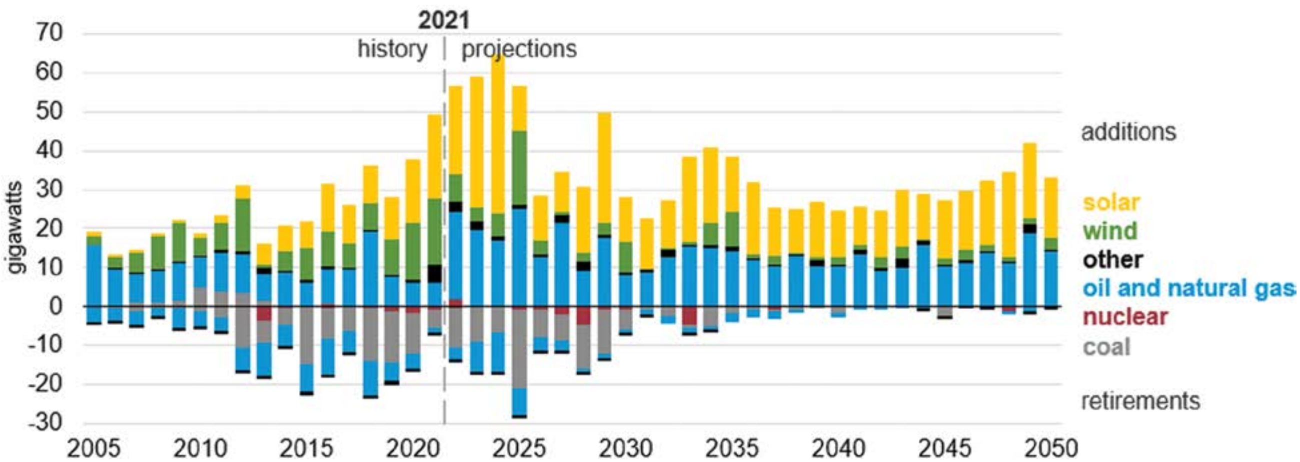
Historically, the most common resource adequacy metrics were capacity focused, indicative of whether there were sufficient resources to serve the peak load across the system. The reserve margin analysis continues to

21 According to BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, "Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability."

offer a transparent, straight-forward metric, but with increasingly complex inputs (e.g., complex load profile and accrediting individual resources) to determine whether an area is "resource adequate" for a given season. The reserve margin metric has limitations, as it is narrowly focused on the peak period for each assessment area. This metric was appropriate for systems comprised of large generation resources that were dispatched with historically dependable fuel sources, such as coal, nuclear, hydro power, and natural gas, but has limitations when applied to wind, solar, and battery resources with energy-limited or variable output operational.[22]

As discussed above, the resource mix in the United States continues to undergo a transformation that has accelerated especially during the past decade. Utility-scale wind and solar have accounted for most of the capacity additions since 2005, followed by natural gas-fired generating units. Unit retirements have primarily included coal-fired generators, older natural gas units, and nuclear plants (**Figure 9**).

Figure 9: Annual Electricity Generating Capacity Additions and Retirements (EIA, 2021)[23]



Most renewable resources have variable fuel sources that impact output and limit dispatchability and controllability by operators. Changing load profiles, periods of high electricity demand resulting from extreme weather events, increasing contributions from flexible loads, and behind-the-meter resources, such as rooftop solar, have further complicated load forecasting practices. The one-event-in-ten-years metric does not consider energy unavailability due to operational conditions impacted by short-term weather events, such as cloud cover and low wind speeds. These changing local or regional conditions can reduce the output of solar and wind, requiring operators to depend on other controllable and dispatchable resources to ensure there is enough energy output to meet system demand.

Growing uncertainties on the load and supply side have introduced varying challenges for system operators in some parts of the country, increasing risks of curtailing electric service to customers, also referred to as firm load shed.[24] **Table 3** summarizes some of the complexities facing system planners and operators.

The ongoing changes to the collective attributes of the resource mix, combined with the growing capabilities on the customer-side to leverage the advantages of demand flexibility, will require more advanced resource adequacy assessments to understand the associated reliability risks. On the demand-side, advanced rate designs, innovative utility programs, and well-crafted regulatory oversight can help leverage these technologies,

22 System planners who use the reserve margin metric often base it on a more detailed probabilistic study, which is further used to identify capacity needs.

23 Solar includes both utility-scale and end-use photovoltaic power generation capacity.

24 Firm load, primarily residential and small commercial customers, is distinguished from non-firm load, which consists primarily of industrial and large commercial customers that have agreed in advance to service with a higher likelihood of interruption. Through contract or tariff, to reduce or forego electric service upon request of the system operator, including non-firm tariffed service or demand response programs.

equipping customers to yield the desired response for supporting system reliability and stability, reducing constraints, and contributing to a more flexible and efficient system. Enhancements to existing capacity accreditation approaches are needed to address the ongoing changes in resource portfolios. Appropriate resource adequacy reforms to existing approaches and the introduction of supplemental methods can provide a more comprehensive and informative assessment for system planners, utility regulators, and policy makers. These reforms are further discussed in Part IV.

Table 3: Growing Complexities for System Planners and Operators

Load (Demand)	Resources (Supply)
• **Growing complexity of load forecasting** with increased variation in load patterns[25] • **Rapid electrification** (transportation and buildings) could increase peak demand and/or shift when the peak load window occurs • **Managing growing levels of behind-the-meter generation**, microgrids, and other technologies • Accurately projecting and accounting for the availability and performance of **demand-side management programs** • Changing frequency of **high demand periods caused by extreme weather events** • **Adjusting inverter-based demand** with asynchronous links to the system so that they respond as intended and support reliability during system events	• Portfolios with increasing levels of resources that have **variable output** • **Adjusting operational practices** to reliably integrate and manage energy-limited or short-duration resources (batteries and hybrid resources)[26] • **Rapid electrification** (transportation and buildings) could increase need for more capacity or other resources to address higher peaks • Increased **risk of fuel supply interruptions** for natural gas resources • Growing proportions of portfolios with resources that are vulnerable to **highly-correlated, weather-dependent outages** • **Higher forced outage rates of thermal resources** due to an aging fleet, reduced investments to maintain plants expected to retire, and operational changes associated with more system variability • **Near-term retirement announcements** of fossil-fired capacity, limiting resource options for system operators • **Decentralization of resources** with wind and solar located further away from load centers; heavier reliance on the transmission system, raising deliverability concerns • **Inverter-based resource (IBR) performance issues** in response to system disturbances and dynamic conditions based on programmed logic and inverter controls[27]

Additional Information on Foundational Resource Adequacy Concepts

- *Electricity Explained: How Electricity Is Delivered to Consumers* – U.S. Department of Energy (Link)
- *Reliability Primer* – Federal Energy Regulatory Commission (Link)
- *Resource Adequacy* – National Renewable Energy Laboratory (Link)
- *EIA Glossary* – U.S. Energy Information Administration (Link)
- *PJM Glossary* – PJM Interconnection (Link)

25)ver-reliance on expert system forecasting tools in the operational time-frame that doesn't account for large increases of demand during extreme weather patterns.

26 The most common form of hybrid resources is battery storage combined with utility-scale solar projects. Other forms include a combination of the following: photovoltaic and storage, wind and storage; wind, PV, and storage; fossil-fired resources and storage; and wind and PV.

27 The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases).

IV. Regulatory Considerations for Evolving Reliability Risks

The electric system continues to integrate more renewable resources, but at different speeds and trajectories throughout the country. At the same time, severe extreme weather events are having larger impacts on the reliability of grid. As new challenges emerge, utility regulators benefit from the most accurate information and effective tools to interpret the evolving reliability challenges across all interconnections and service territories. In developing this report, the regulatory community identified and prioritized three specific issues for consideration: resource adequacy reforms and supplemental approaches; regulatory considerations for extreme weather events; and the interplay between state resource planning and regional reliability. This section describes these issues and offers potential strategies, tools, case-studies, and lessons-learned to inform state commissions as they navigate various regulatory decisions related to the system impacts of a changing resource mix, extreme weather events, and regional impacts from neighboring state policies and actions.

Resource Adequacy Reforms and Supplemental Approaches

America's electric grid continues to evolve with growing amounts of variable generation (wind and solar), battery storage, advanced forms of energy efficiency, evolving demand response programs, distributed generation, and other emerging technologies. Amidst these changes. extreme weather events, environmental policies, affordability concerns, and rapid electrification present competing priorities as utility regulators work to also maintain reliable systems in their respective states. The ongoing retirement of capacity that is highly dispatchable and controllable, combined with the addition of resources that are predominantly non-dispatchable, has contributed to reduced planning reserve margins in most areas, which increases the potential for shortfall events (Carvallo, et al., 2023). Additionally, traditional resource adequacy methods that have served the industry well historically, are no longer capturing the risks associated with more variable renewable energy, energy-limited storage, flexible loads, and the potential for correlated outages for all resource types during extreme weather events. Criticisms for traditional metrics include (Carvallo, et al., 2023):

- Limited insights on the potential for shortfall (in terms of frequency, duration, and magnitude)
- Lacking information on the specific risk period and timing of a shortfall event
- Examining an entire system without consideration for local adequacy

As the industry's technical community continues to grapple with how to best reform resource adequacy modeling approaches to better understand the changing risks, it is important that utility regulators are aware of these developments so that they can incorporate new information into their decisions. In many cases, experts are still engaged and deliberating approaches in technical discussions, stakeholder initiatives, and market design changes throughout the country to identify the appropriate resource adequacy reforms. Ultimately, the regulatory community can make more informed decisions on resource additions and retirements with a robust understanding of the underlying reliability implications.

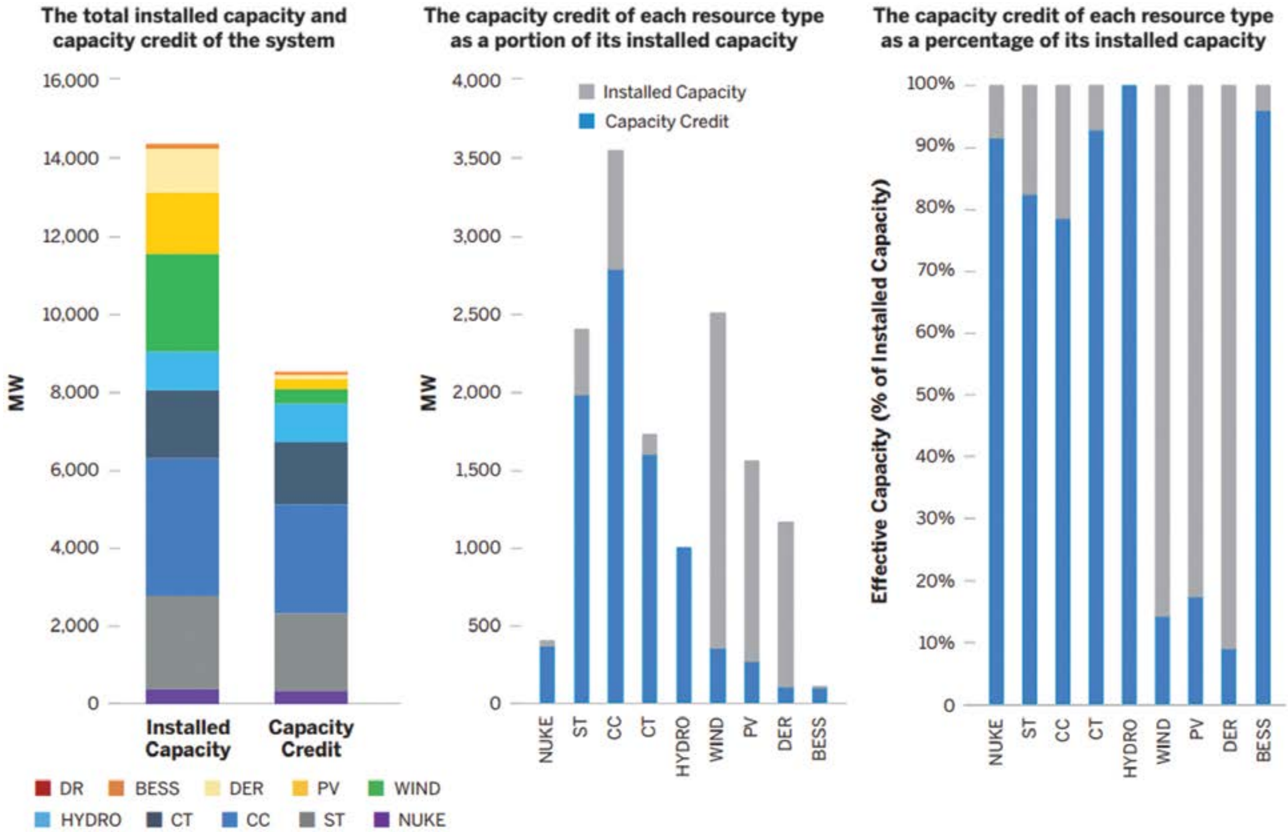
The objective of this section is to examine some of the evolving resource adequacy concepts and how they may help state utility regulators better understand the potential reliability impacts of resource decisions in the systems they regulate. These include capacity accreditation, energy adequacy, measuring and tracking grid reliability services, and scenario analysis. While this is not a comprehensive list, it does address many of the approaches currently under consideration to improve-upon or add to the array of resource adequacy tools. The intent is not to promote any single approach, but to raise awareness of existing and developing tools.

Capacity Accreditation

The resource adequacy analysis and related metrics discussed in Part III generally assess whether there are enough resources to serve peak load on a system for a specified study period. Approaches for determining how much capacity will be available during the peak period (the resources counted in the PRM analysis) include

ICAP and UCAP (typically used for thermal resources), and ELCC (commonly used for energy limited resources or resources with variable output). After identifying how much capacity is needed to exceed or maintain an established level of reliability (e.g., a reference margin level based on a 1-day-in-10-year LOLE criterion), system planners can apply a capacity accreditation method (or combination of methods) to determine how much capacity can be relied upon from each resource or resource type. **Figure 10** illustrates how different resources are accounted for during the peak period, using a commonly used installed capacity (ICAP) approach.

Figure 10: Installed Capacity vs. Capacity Credits Across Resource Types (ESIG, 2023)



While a resource type may account for a large portion of a system's installed resource mix, its capacity contribution during the peak period may be significantly lower. However, the ongoing changes to both the resource mix and load profiles are shifting risks away from a conventional peak period (e.g., summer afternoon) and toward broader risk periods throughout the season. This underscores the importance of examining the performance and resource adequacy contributions of different resources during different periods outside of the peak (ESIG, 2023).

More advanced forms of capacity accreditation provide a more robust analysis of specific resource performance and output beyond the peak period. Such approaches account for the frequent variation in capacity contributions of a changing resource mix. There are several accreditation methods, many of which are still under development. Planners may choose to incorporate different techniques for each resource type or design a multi-metric approach that is tailored for a system's specific resource portfolio. Regardless of the approach, inputs that inform the selected accreditation method will benefit from regular updates that keep pace with the changing performance of the entire resource mix of various systems.

According to the Energy Systems Integration Group (ESIG), "accreditation methods can be characterized by three overarching elements that need to be considered when evaluating a capacity accreditation technique (ESIG, 2023)." These elements are summarized in **Table 4**:

Table 4: Common Capacity Accreditation Methods

Deterministic vs. Probabilistic	Deterministic metrics use a single-point estimate, often based on historical performance (similar to the calculation of the reserve margin metric discussed in Part III).
	Probabilistic metrics use analytical simulations across hundreds or thousands of potential future conditions. Probabilistic assessments for specific resources share some similarities to the applications for determining a reference margin level (described in Section I). In the case of performance, this approach examines the probability of a resource's availability during periods of higher risk, examining its contribution toward reducing or eliminating a potential loss-of-load event.
Prospective vs. Retrospective	Prospective (forward-looking) methods are often used in the planning and investment time frame to help understand the incremental benefits of future resources.
	Retrospective (historical) approaches include the use of historical operating conditions to inform resource accreditation.
Marginal vs. Average Contribution (ELCC)	A marginal ELCC approach accredits the entire cohort of a resource type based on the reliability contribution of incremental additions to that resource type. A marginal approach ultimately measures the contribution of a resource type based on its ability to reduce loss-of-load events for an incremental addition of installed capacity, relative to the amount of fixed load that can be added. The marginal approach can be applied by calculating the total amount of effective capacity (firm capacity) needed to meet the resource adequacy criterion (the PRM).
	An average ELCC approach accredits the entire cohort based on the contribution of the entire fleet. Specifically, it is a measurement of the aggregate contribution of the entire resource type (e.g., the contribution of all wind generation on the system).

These different methods for measuring capacity accreditation have varying advantages and disadvantages for resource planners. In many cases, planners use a combination of techniques and assumptions that are specifically tailored for each system.

Other Methods for Consideration

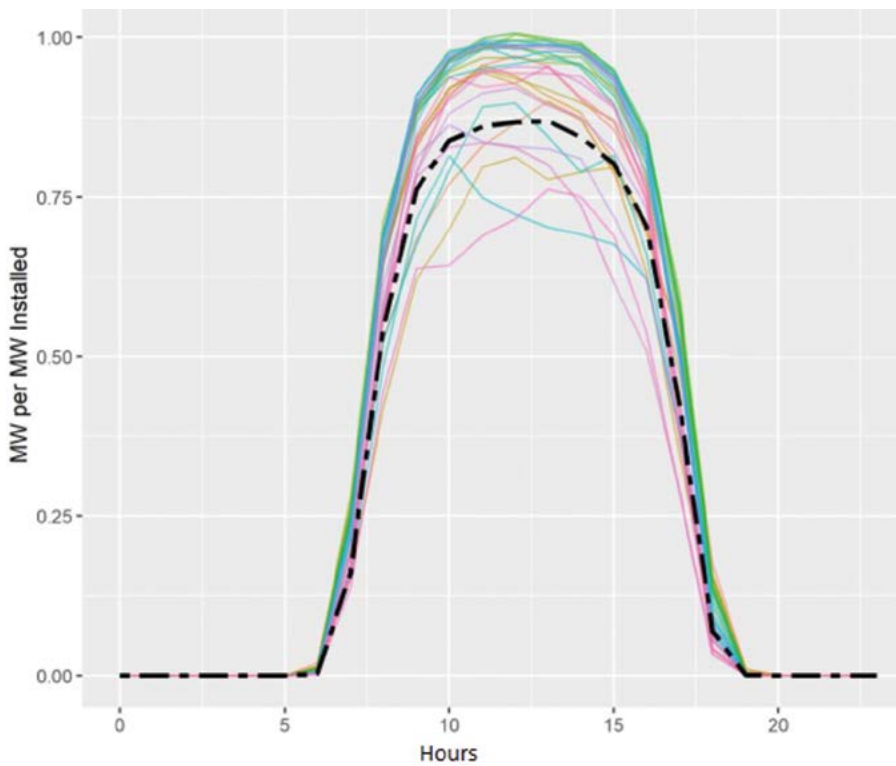
Resource adequacy assessments for many areas continue to implement simplistic capacity accreditation methods centered entirely on a specific peak load window—usually during the late-afternoon when demand is forecasted to be the highest. This deterministic approach considers average, or percentile, output relative to a resource's nameplate capacity during the load window(s) (ESIG, 2023). As discussed in Part III, this approach assumes that the available capacity during the highest level of system demand is the most important and meaningful way to measure a resource's capacity accreditation. These resource adequacy approaches were appropriate for systems with a resource portfolio comprised of highly controllable and dispatchable resources but become less effective as shifting load profiles and variable or energy-limited resources shift or introduce new periods of risk. Moreover, the operational challenges associated with new resources and loads require examining risk periods outside of the peak load window. The implementation of forecasting methods that examine the peak net load (total load, less projected wind and solar output) are increasingly common in areas with higher levels of renewable resources. Wind and solar resources offer more capacity, but actual output is dependent on weather conditions. As a result, operators have identified multiple risk periods when system conditions are tight.

Examining the peak net load in forecasting and operational practices is useful because it isolates the variability of wind and solar for that system operators. A 2023 report published by the Lawrence Berkely National Laboratory, examined a wide array of resource adequacy assessment practices, conducted interviews with practitioners, and reviewed recent technical literature. One of the report's findings was that "…basing [resource adequacy] assessments on the peak hour of the year or season, or on a few select top load hours, is insufficient as peak demand may no longer predict the times when the power system is most stressed. Chronological hourly simulations are the current best practice (Carvallo, et al., 2023)." System planners are responding with the development of deterministic and probabilistic analyses aimed at better understanding these risk periods–-particularly how to evaluate the capacity accreditation of an entire portfolio, accounting for the interplay between resources with different attributes. Two of these approaches, exceedance and slice-of-day, are explained below.

Exceedance: The exceedance approach is a deterministic estimation of the minimum expected output from a resource during a specified study period (Pappas, 2021). The selection of a 70% exceedance level for a resource assumes the amount the resource will produce at least 70% of the time. For example: A 70% exceedance level of 10 MW for a 30 MW resource means that the resource, while capable of producing 30 MW, is assumed to produce at least 10 MW of output during 70% of the assessed period (ESIG, 2023).

The exceedance concept is demonstrated by the dashed line in **Figure 11**, which indicates solar production output with an exceedance of 75%. The colored lines show 60 days of actual solar production on the CAISO system during two Septembers (2018 and 2019). Accordingly, 75% of the colored lines are above the black dashed line, while 25% are below.

Figure 11: CAISO 75% Exceedance for September 2018-2019 (Pappas, 2021)



Slice-of-Day: A more sophisticated capacity accreditation approach can be observed through the proposal of a 2021 CPUC order to reform California's resource adequacy program. By transitioning to a "Slice of Day" framework by 2025, California will significantly modify how the future performance of all resources are modeled. Specifically, this resource adequacy framework calculates exceedance across a 24-hour profile that identifies potential periods of insufficient or surplus generation at different hours throughout the year (CPUC, 2023). This approach examines "energy adequacy" of different resource types instead of modeling around the peak demand period. The proposed exceedance parameters for highly-variable resources, such as solar and wind, will assign values for each hour across multiple months, based on historical observations, thus requiring no specialized modeling. The assumptions and examined periods may be limited to "resource adequacy hours" or hours when system conditions are projected to be tight. For example, the California ISO has proposed examining the top 5 days, plus flex alert days, with the following basis for analysis (CPUC, 2023):

- Exceedance percentages based on a high-load profile (70% in summer months (Jun-Sep); 50% in non-summer months (Sep-May))
- Final product will be a 288 (12 months x 24 hours) capacity factor profile
- Uses actual production data, applied for a technology class and regional profile

Ongoing proposals for capacity accreditation for resources are underway in electric systems throughout the country (**Table 5**). As new approaches or enhancements to existing approaches are developed and implemented, it is important that the underlying method is transparent to involved stakeholders (including utility regulators) and can be applied consistently to changing systems in a way that promotes future reliability. There are many reports and forums for the regulatory community to participate and stay engaged as new methods are introduced and implemented, identified throughout this report.

Table 5: Accreditation Methods in Different Systems

System	Accreditation Methods as of October 2023	
	Wind & Solar	Thermal
CAISO	Slice-of-Day (exceedance across each month and hour within a day)	UCAP
ERCOT	Based on performance during the top 20 peak load hours using 10-year historical averaging approach for each season	ICAP; based on reported "Seasonal Maximum Sustainable Limits" and reducing by outage data from the last 3 seasons (ERCOT, 2023)
ISO-New England	Median performance during pre-defined reliability hours / system-wide scarcity condition hours), averaged across the previous 5 years (Newell, Spees, and Higham, 2022).	ICAP based on maximum output during peak demand condition (Newell, Spees, and Higham, 2022).
MISO	Seasonal average ELCC; scaled based on unit specific performance during the season's top 8 peak load hours (wind). 3-year historical average peak output (solar)	UCAP EFORd, scaled based on actual performance during tight margin hours
NYISO	Based on demonstrated capacity factor during specified seasonal peak load hours during the prior year's capability period; Marginal ELCC approach under development	ICAP derated for EFORd (NYISO, 2021)
PJM	Adjusted-class Average ELCC, based on class-level results and resource performance (FERC, 2021)	UCAP EFORd

SPP	Based on 60th percentile of output during the highest 3% of load hours of each month using 3+ years of data (SPP, 2019); ELCC approach under development	ICAP; accredited according to their tested maximum deliverable output, without derating for EFORd
Southeast (Non-Market)	Varies by utility.	Varies by utility
Western Interconnection (Non-Market)	Varies by utility; of 11 observed, 9 currently use ELCC; 2 use alternative approaches (E3, 2022);* WRAP is currently exploring an ELCC approach	Varies by utility

*The following utilities use an ELCC approach: El Paso Electric Co, Public Service Company of New Mexico; Salt River Project; Avista Corporation; Idaho Power Company; Nevada Power Company; Portland General Electric; Public Service Company of Colorado; Puget Sound Energy. The following utilities use an alternative approach: Arizona Public Service Co; Tucson Electric Co.

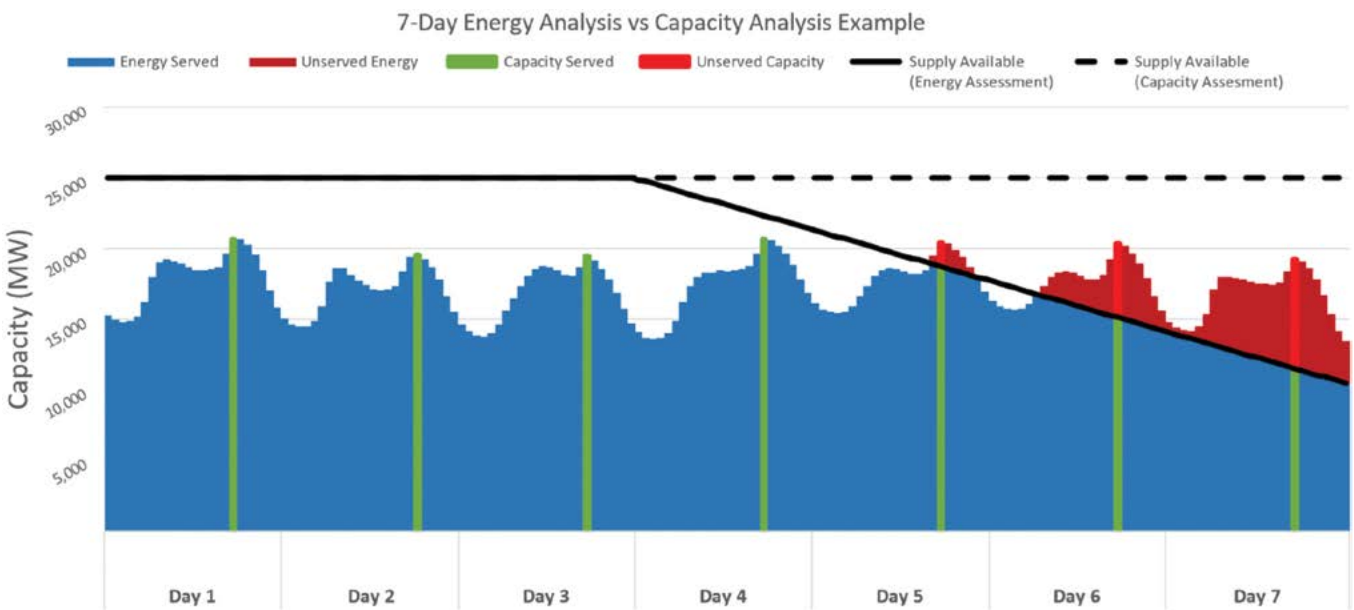
Energy Adequacy

The assumptions of the 1-day-in-10-year LOLE and similar planning standards posited the notion that meeting a capacity threshold would imply adequate resources to meet loads at all times during the planning period. However, with the evolving resource mix, this is no longer a safe assumption. As periods of risk or tight conditions shift outside of the peak period, examining energy adequacy on an hourly basis is one way to sustain a reliable system amidst the grid transformation. According to ESIG, "the conventional assumption that peak risk is aligned with peak load is no longer true, requiring a chronological evaluation of all hours of the year so that the times of risk of shortfall can be accurately identified (ESIG, 2021)." LBNL further highlightsthat there is general agreement among industry experts to include energy adequacy, either within establishedassessment processes or as supplementary analysis (Carvallo et al., 2023).

Energy adequacy implies that the resources can be leveraged to produce enough energy to serve demand at any given time during the assessment period. Energy constraints in some areas due to dynamic or variable output must be specifically assessed. Energy assessments of sufficiency or adequacy involve projecting the amount of electricity a resource will produce during a specified time-period (multiple days, weeks, or months), and expressed in megawatt-hours (MWh). Also known as "chronological assessments," this analysis examines how the energy availability on a system will vary based on resource limitations. Accordingly, energy adequacy assessments require carefully crafted assumptions and significantly more data to create accurate hourly resource performance projections.

The concept is demonstrated through an example developed by NERC (**Figure 12**). The figure highlights the potential limitations of a capacity assessment that examines only the peak load windows (green vertical lines). Although the capacity assessment indicates adequate levels of capacity (based on the assumed output during the peak window), an energy assessment captures the unserved capacity due to the modeled fuel supply failures of natural gas generators. Based on an assumed interruption, dual-fuel units would switch to oil as a primary rule during Days 1-4, potentially depleting these reserves during Days 5-7 (without oil replenishment). The energy assessment highlights the risk of unserved energy (dark red) in later days of the study period, due to depleted fuel.

Figure 12: Energy Assessment vs. Capacity Assessment (NERC, 2023)



Planners can also establish an energy reserve margin threshold (similar to a reference margin level discussed in Part III). If the study is constructed properly, it can identify the system's adequacy for all hours of the study period, rather than simply during peak load hours (EPRI, 2022). Energy assessments are particularly useful for systems with high levels of variable renewable energy and/or energy-limited resources. These assessments could be particularly useful for systems with growing amounts of battery storage and demand response, providing useful insights on potential discharge and dispatch schedules (ESIG, 2021). According to LBNL, "Energy adequacy for energy-constrained resources will become more relevant as penetration of these resources increases, and possibly due to more frequent and severe droughts that affect hydro energy availability (Carvallo et al., 2023)." Modeling the availability of these resources over multiple hours can help planners and operators optimize theuse of energy-limited resources as demand fluctuates. LBNL further indicates that there are currently no widelyaccepted practices to evaluate energy adequacy, compared to the established stochastic resource adequacyapproaches (Carvallo et al., 2023).

Measuring and Tracking Grid Reliability Services

The concept of "reliability services" has been discussed among system planners and operators for many decades. While the terminology has been refined and formalized more recently, frequency response, voltage support, voltage control, reactive power, and ramping capability are all necessary for maintaining a stable grid—particularly for the bulk power system. Essential reliability services ultimately measure system attributes that allow operators to keep the lights on.

The resource mix during the 20th century was comprised of hydroelectric, fossil-fired, and nuclear resources that provided the appropriate combination of reliability services. Specifically, coal, nuclear, hydroelectric, and combined-cycle natural gas plants contributed stable, "baseload" generation that included voltage support, inertia (large spinning mass), and reactive power. Combustion turbine natural gas and hydroelectric units offered operators additional benefits of readily available ramping capability to address rapid changes in demand. Until energy storage is fully developed and available at scale, system operators continue to rely on sufficient levels of flexible, controllable, and dispatchable generation to balance supply and demand.

With the ongoing transition in the resource mix throughout the country, added variability has complicated modeling practices on the supply and demand sides of the system. In response to these developments, NERC launched a task force in 2014 to examine ongoing impacts to overall system attributes amidst a resource mix transformation (NERC, 2016). The efforts of NERC's Essential Reliability Services Task Force ultimately identified and proposed ERS measures in 2015 to examine and potentially monitor trends related to frequency response, ramping and balancing, and voltage support. A NERC Reliability Standard is already in place that requires various entities to maintain adequate system restoration, including the retention and maintenance of facilities that are blackstart-capable (NERC, 2018). Additional details on various grid reliability services are provided below:

- **Frequency Support:** Imbalances in the amount of generation available to meet electricity demand results in a change in frequency (overgeneration leads to increases in frequency, while inadequate generation results in a drop in frequency) (Joseph, 2022). A system with adequate frequency support will have sufficient resources available to quickly respond to changing system frequency. This reliability service is provided through the combined interactions of synchronous inertia and frequency response, which both support arresting the decline in frequency and eventually returns it to the desired level. Frequency support is particularly important in areas with lower levels of synchronous inertia or to respond to a forced-outage of a large generator, which causes system-wide frequency to immediately drop. The combined response of resources capable of responding to this decline in frequency by quickly injecting power output can help stabilize the drop throughout the system. Some load-side resources, such as certain controllable and dispatchable demand response or qualifying battery storage resources can provide frequency support. Utility regulators may wish to examine metrics that track frequency response in both their balancing area and throughout the interconnection. Maintaining a resource mix with adequate frequency response capabilities should be considered when examining a system's existing and future resource mix (NERC, 2016).
- **Ramping and Balancing:** Ramping capability is related to the maintenance of frequency levels but used regularly by system operators to ensure a balance between instantaneous supply and demand. High-levels of non-dispatchable resources, varying system constraints, and unpredictable load behavior (large swings in customer demand) will impact ramp rates and impact system balance. Certain resources have historically been relied on to respond to the changing aggregate system variability. For example, single-cycle natural gas turbines, and some reservoir hydro units can be quickly dispatched to increase or decrease output to help address changing system conditions (including rapid changes on the demand-side as well). Today there are many sources of needed system flexibility (ramping and balancing), on both the demand and supply side, as well as through regional and interregional transmission. Accordingly, utility regulators may wish to examine the availability of resources capable of providing system ramping and balancing throughout the electric service territory that they regulate.
- **Voltage Support:** This system attribute involves the management of reactive power flows to maintain voltage within predefined limits on various components of the grid. This is important during both steady-state conditions and for recovery following a system disturbance. Voltage control tends to be more local in nature, addressing deficiencies in reactive power (e.g., individual transmission substations, lower voltage transmission nodes, and the distribution system). Static and dynamic reactive power reserve capabilities are more granular system attributes that both help regulate voltage at various points on the system. Voltage support is ultimately provided by resources that are capable of injecting static and dynamic reactive power, aiding system operators in their regulation of voltage levels at various points on the system. System operators monitor these measures to determine the levels of voltage control available to maintain reliable system performance within the electric service territory.
- **Blackstart Capability:** If power is lost throughout an entire system, blackstart services are designated generators with attributes needed to restore electricity to the grid without using an outside electrical supply (e.g., on-site auxiliary power). Ensuring that there are enough blackstart resources on a system is critical for bringing the grid back online in the event of a widespread blackout. In 2018, a joint FERC-NERC report recognized a "decrease in the availability of blackstart resources due to retirement of blackstart-

capable units over the past decade (FERC, NERC, 2018)." System operators continue to regularly examinearea plans for restoration and recovery of the bulk-power system following a widespread outage, includingthe adequate availability of blackstart units.

While reliability services are technically separate from resource adequacy, they play a vital role in maintaining a reliable system. To address the ongoing changes to the resource mix, regulatory considerations for the impacts of a utility's proposed resource decisions on maintaining adequate levels of these services can help support local, regional, and interconnection-wide reliability. New forms of generation on the system, including higher levels of wind, solar, battery storage, and demand flexibility, can offer a wide range of reliability services that are also offered from grid-forming inverters, compared to those provided by grid-following inverters. System planners and operators have been grappling with the impacts of a changing portfolio of grid services provided by these resources. This requires more advanced computational and modeling approaches to evaluate and determine how a changing resource mix with additional inverter-based resources can be leveraged to contribute adequate levels of frequency response, ramping capability, and voltage support across each system.

Scenarios Analysis

Assessments that examine the potential system impacts due to a low-probability event can be useful and informative for utility regulators when determining whether to make strategic investments to improve resilience or "harden the grid." Adding a range of scenarios to established approaches can further enable utility regulators to identify system vulnerabilities and respond appropriately. This is particularly useful for assessing the impacts of wide-spread and prolonged extreme weather.

Traditional resource adequacy assessments, including the reserve margin metric, integrate actual historic weather conditions, and to a lesser extent, long-term weather modeling as factors used to forecast seasonal loads. However, the approach generally assumes expected weather and masks the tail-ends of the distribution (i.e., abnormally hot summers). The direct or indirect impacts resulting from changing climate conditions, including more frequent and/or severe extreme weather events, will impact the overall risk profile for the resource mix. As a result, traditional resource adequacy metrics become less effective in painting an accurate picture of projected system reliability and performance. The most extreme and obvious examples occur when extreme and prolonged heat waves and cold snaps cause correlated resource outages.

Scenarios to Examine Limited Resource Availability

The reserve margin metric incorporates the general performance of a resource based only on its forced (unexpected mechanical failures) and unforced (planned maintenance) outage rate. It does not explicitly consider common-mode failures, correlated outages, and fuel supply interruptions (e.g., natural gas delivery) that can rapidly impact a large portion of a system's generation fleet. For example, a standard wind plant is comprised of many smaller inverter-controlled and independently operated turbines. The failure of a single turbine will impact system operations far less than the failure of a single large nuclear unit (ESIG, 2021). Forced outage rates for different resource types in a generation fleet are typically based on past performance, using multiple years of data. These mechanical and electrical outages are assumed to occur randomly (in terms of the location of the resource and timing of the outage) (ESIG, 2021). Resource adequacy approaches do not explicitly incorporate potential impacts of extreme weather events, including limitations of individual resources or directly account for fuel supply interdependencies, flexibility constraints, and common points of failure (ESIG, 20221).

The recent shift to more natural gas-fired resources in many areas has increased the risks associated with fuel supply, which can lead to common-mode failures for natural gas generators. Areas that rely on a generation portfolio with a large or growing dependence on a single fuel type increase their exposure to correlated or common-mode outages. A diverse generation fleet is inherently more resilient, allowing system operators to leverage a variety of alternative resource types when one is compromised. NERC recommends that "regulators and policymakers in risk areas should coordinate with electric industry planning and operating entities to develop policies that prioritize reliability, including those that would promote the development and use of flexible resources, and maintain a sustainable and diverse generation mix (NERC, 2021)."

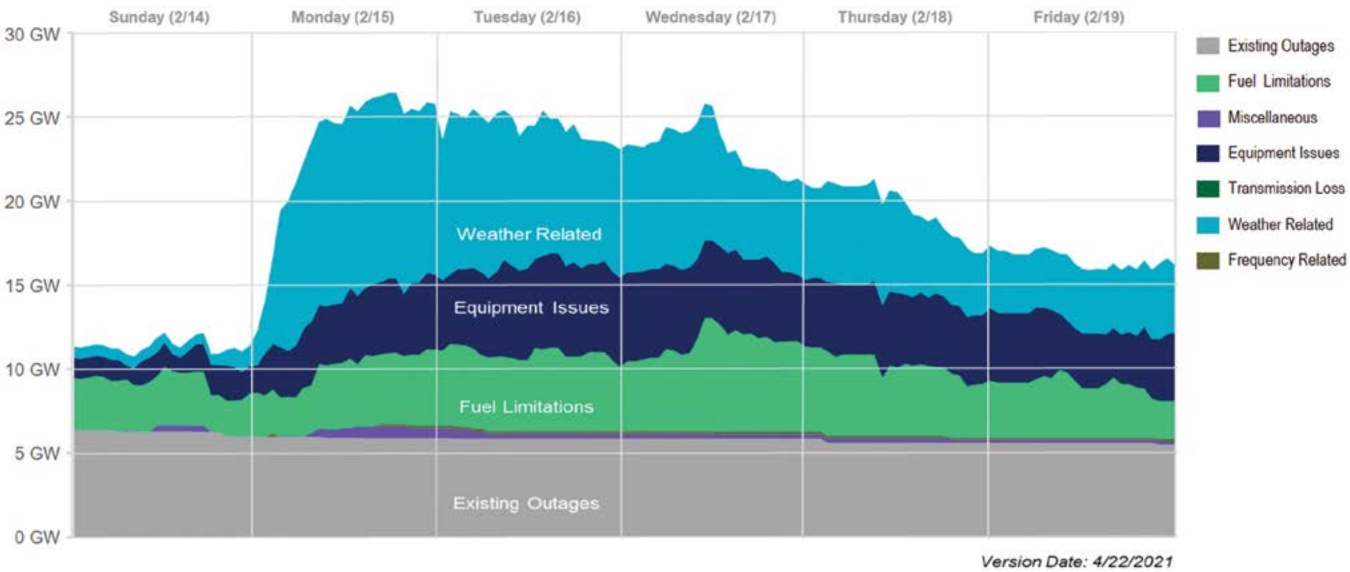
The electric power sector in many regions of the country is increasingly coupled with the natural gas delivery system, which delivers fuel on demand, with little or no storage on-site for generating units (ESIG, 2021). In some cases, dual-fuel capabilities can alleviate supply constraints and interruptions, with units able to switch to standby oil or diesel. Dual-fuel units may require frequent replenishment, which can be limited by severe weather conditions. **Table 6** captures the amount of natural gas natural-gas fired capacity in systems throughout the country.

Table 6: Natural Gas-Fired Resources as a Percentage of Total Capacity by Area

CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SERC	SPP
47%[28]	42%[29]	52%[30]	42%[31]	63%[32]	47%[33]	50%[34]	36%[35]

Natural gas fired resources accounted for 41.8% of ERCOT's generating capacity and 42.6% of total energy use in 2022 (ERCOT, 2022). Fuel supply concerns remain a growing reliability risk, as demonstrated in ERCOT during Storm Uri in February 2021 (**Figure 13**).

Figure 13: Natural Gas Outages by Cause (ERCOT, 2021)



28 2022 total in-state generation (including some resources in balancing authorities outside of the CAISO system). Natural gas accounted for 39,449 MW, or 46.6% of total installed in-state electric generation capacity (84,617 MW) (CEC, 2021).

29 Percent rounded (ERCOT, 2022).

30 As of 2022, nearly half of the ISO-New England's electric generating capacity uses natural gas as its primary fuel (about 15,000 MW in 2022), accounting for 52% of annual generation and 45% of net energy for load (NEL) (ISO-NE, 2022).

31 Percent rounded (MISO, 2023).

32 51% of the NYSIO fleet is categorized as Dual Fuel (Gas/Oil). These units are fueled for most of the year by natural gas, with capability to switch to oil. 12% of the NYISO fleet is categorized as natural gas-fired, without fuel switching capability.

33 In the region PJM serves, natural gas is 46.6% of total installed capacity (PJM, 2022).

34 As reported by member utilities in SERC (SERC, 2022).

35 Based on nameplate capacity (SPP, 2022)

Correlated outages occur when multiple power plants face the same vulnerabilities to concurrent fuel supply interruptions or unit failures. NERC has highlighted the concern:

> The thermal generation fleet has transitioned from a diverse mix of fuel types to one that is increasingly dominated by natural-gas-fired generation. While all generator types can be expected to have increased forced outages in extreme weather, natural gas as a generator fuel is not typically stored on-site, resulting in greater risk of fuel supply disruption (NERC, 2022).

Important lessons can be extracted from how Texas responded to ERCOT's system performance during Winter Storm Uri. Utility regulators were required to examine system shortfalls and oversee investments to protect electric systems with related penalties for non-performance. The New York ISO and ISO-New England are also exploring requirements for dual-fuel capability for natural gas generators. According to ISO-New England, recent winter events have resulted in regional gas utilities using most, if not all, of the capacity on their pipelines, particularly during extended periods of extreme cold temperature when heating demand is high. During these periods, electric generators may experience delivery interruptions and potential failures on the power system (ISO-NE, 2023).

Regulatory decisions that incorporate the reliability impact of a utility's proposed future generation portfolio can be informed by a better understanding of the attributes and limitations of each resource type. Ultimately, it is important for utility regulators to recognize that all resource types have unique operational attributes and associated vulnerabilities (**Table 7**) that can be identified in scenario assessments.

Table 7: Resource Attributes and Vulnerabilities

Resource	Attributes	Vulnerabilities
Nuclear	• Large units; greater outage impacts • Baseload • Consistent output	• Type-faults impacting multiple units • Long outages for refueling • Supply chain • Cooling water limitations • Pmin limitations (i.e., unit cannot run below a minimum energy output)
Coal	• Large units; greater outage impacts • Baseload • Consistent output • Spinning mass / inertia	• Frozen coal piles • Cooling water limitations • Supply chain (related to mining /refining)
Natural Gas	• Medium/large units; greater outage impacts • High ramp rate	• Fuel supply constraints • Exposed auxiliary equipment failure • Correlated/common-mode outages • Cooling water limitations (for some plants)
Hydro	• Large unit; greater outage impacts • Baseload • Spinning mass / inertia	• Fuel supply limitations for run-of-river, small, reservoir, large reservoir (drought) • Pmin limitations (i.e., unit cannot run below a minimum energy output)
Wind	• Variable output • Smaller unit; reduced outage impacts	• Variable output (high/low wind speeds) • Icing of turbines

Solar	• Variable output • Smaller units; reduced outage impacts	• Variable output (smoke, fog, clouds) • Ice/snow cover • Inverter performance issues
Battery storage	• Short-term output • Instantaneous grid services	• Limited duration / uncertain charging times • Mis-timed discharge • Transmission constraints may limit charging capability during certain periods
Hybrids	• Consistent output	• Limited duration for widespread, long-duration weather events
Demand Response	• Visible to the system operators • Avoids siting, permitting, and construction time required for new capacity	• Limitations of legacy programs • Price sensitivities • Actual response lower than anticipated • Limited commitment periods • Limitations in providing energy and reliability services
Transmission	• Robust systems alleviate constraints and improve system stability	• Outages during extreme weather • Congestion • Planning, siting, and permitting challenges

The potential for generator outages increases during extreme high and low temperatures, causing unit equipment failures, fuel supply issues and other impacts. Correlated outages or common equipment failures often occur across an area during a prolonged heat wave, cold air outbreak, or other extreme weather event. Additional regulatory considerations for extreme weather events will be addressed in the next subsection. Potential impacts to resource output during extreme demand conditions are provided in **Table 8**.

Table 8: Resource Impacts During Periods of Extreme High or Low Temperatures

Extreme High Temperatures or Drought	Extreme Low Temperatures
• Higher ambient temperatures reduce output from fossil-fired and some solar resources • Reduced wind output (wind speeds are generally lower during extended periods of high-temperatures after a warm front has passed through a region) • Increased failure rate of auxiliary or operational equipment • Need for modified or increased active cooling equipment for thermal units • Limitations to the use of cooling water for nuclear and fossil-fired resources when surface-level temperatures exceed established operational bounds • Generator outages or derates due to forced outages or derates on directly connected transmission facilities	• Frozen coal piles can limit output from coal-fired plants • Increase failure rate of auxiliary or operational equipment, including: frozen sensing lines, frozen water lines, and frozen valves • Fuel limitations, particularly for natural gas resources due to line pack instability, lower pressure, or failed compressor stations • Equipment failure when switching fuel (from natural gas to oil) • Ice accumulation on wind turbine blades • Exceedances of low temperature limits for wind turbines

Extreme High Temperatures or Drought	Extreme Low Temperatures
• Reduced run-of-river hydro power resources due to drought conditions from prolonged periods of higher regional temperatures • Environmental run-time restrictions • Transmission congestion, increased line sag, and reduced line capacity • Increased energy loads due to water pumping and irrigation • Increased probability of wildfire that may impact transmission or generation	• Ice/snow cover on solar panels • Ice/snow accumulation on transmission and distribution lines, leading to failure • Flooded equipment due to ice/snow melt • Generator impacts from forced outages or derates on directly connected transmission facilities • Increased transmission congestion, line sag, and reduced line capacity • Operational impacts to the railroad system leading to inability to deliver coal to generators

Generator failure rates are typically derived by examining the distribution of outages over a longer period and are constantly updated with the most current performance data. This data can be incorporated into a reserve margin scenario analysis, offering a performance-based estimation of potentially reduced resource availability. Reductions can be based on historic rolling five-year averages of planned and unplanned (forced) outages, as well as the highest level of generator outages recorded for a given area. While these outages are modeled as random, independent equipment failures in terms of location and timing, more recent examples of widespread outages highlight a need to also model common mode events through scenario planning. The following example demonstrates how reducing resource availability during the peak can impact an assessment area's planning reserve margin:

$$\text{Planning Reserve Margin} = \frac{\textbf{Effective Capacity} - \text{Peak Load Forecast}}{\text{Peak Load Forecast}} = \frac{\textbf{25,000} - 20{,}000}{20{,}000} = 25\%$$

$$\text{Planning Reserve Margin} = \frac{\textbf{Reduced Capacity} - \text{Peak Load Forecast}}{\text{Peak Load Forecast}} = \frac{\textbf{24,000} - 20{,}000}{20{,}000} = 20\%$$

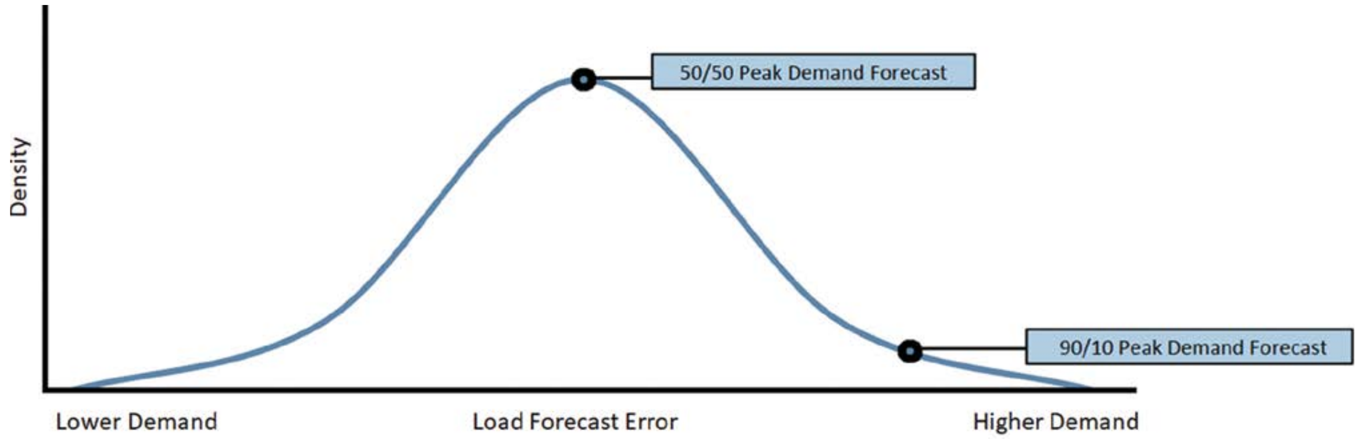
This analysis, while simplistic, offers additional insights for utility regulators in examining how extreme demand and/or wide-spread generator outages can impact the inputs for a system's planning reserve margin.

Extreme Demand Scenarios

Traditional resource adequacy assessments capture the distribution and probability of temperature impacts through sophisticated load forecasting methods, informed by a robust dataset of historic conditions, combined with long-term weather outlooks. Load forecasters are still grappling with how to directly account for potential extreme demand periods. This challenge is illustrated by observing ERCOT's Winter 2020/2021 Seasonal Assessment of Resource Adequacy, which forecasted a winter peak of 57,699 MW, based on normal weather conditions using several years of historic data. The assessment's scenario-adjusted extreme load forecast was 67,208 MW, based on the 2011 winter and a revised economic growth forecast prepared in April 2020 (ERCOT, 2020). Actual peak demand during that season reached 69,215 MW during Winter Storm Uri, nearly 20% above the normal weather forecast and 3% above the extreme weather forecast. It is important to note that actual demand was still within the distribution of the load forecast, but at the tail end. Additionally, the extreme demand scenarios discussed in the prior section offer important insights by examining the tail ends of the load forecast distribution.

The reserve margin analysis has several advantages as a deterministic approach with inputs that can be modified or adjusted to highlight potential system risks. For example, an extreme demand (90/10) or 90th percentile load forecast can be used in place of a normal (50/50) load forecast. Moreover, there is only a 10% probability that demand will be higher (**Figure 14**).

Figure 14: Normal vs. Extreme Demand Forecast (Hodge et al., 2013; NERC, 2012)



The following example demonstrates how using an extreme load forecast can impact an assessment area's planning reserve margin:

$$\text{Planning Reserve Margin} = \frac{\text{Effective Capacity} - \textbf{Peak Load Forecast}}{\textbf{Peak Load Forecast}} = \frac{25{,}000 - \mathbf{20{,}000}}{\mathbf{20{,}000}} = 25\%$$

$$\text{Planning Reserve Margin} = \frac{\text{Reduced Capacity} - \textbf{Extreme Load}}{\textbf{Extreme Load}} = \frac{24{,}000 - \mathbf{22{,}500}}{\mathbf{20{,}000}} = 11\%$$

By using the 90/10 extreme load forecast, which is assumed to be 2,500 MW higher than the 50/50 load forecast, the area's planning reserve margin is reduced from 25% to 11%, drastically increasing the potential for a loss of firm load event during the peak period. In this example, all resources are still assumed to provide their expected output, which is unlikely, as extreme demand often strains the grid, resulting in higher outage rates for generating units.

Scenario Applications in Existing Assessments

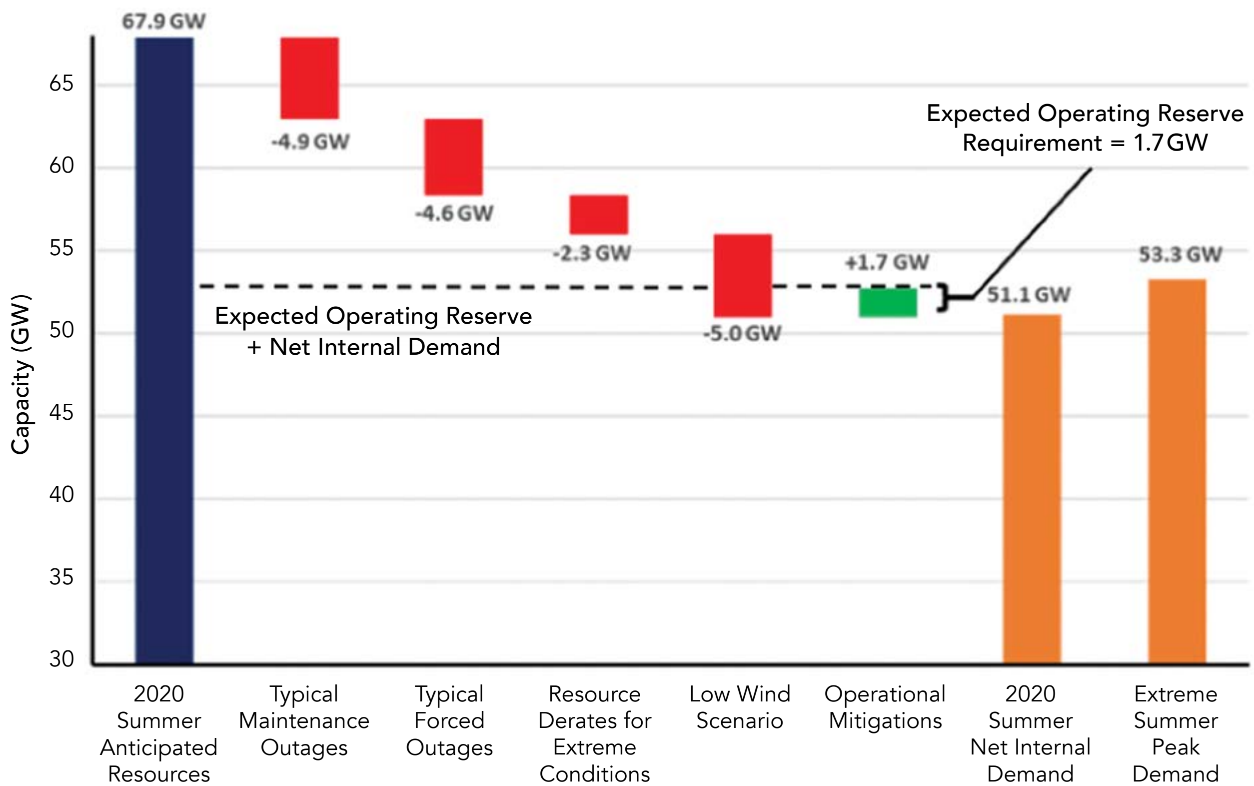
Several system operators throughout the country conduct seasonal assessments with varying scenario assumptions that independently isolate extreme demand and generator outages. Scenarios that examine common-cause outages are particularly useful because they are less subjective and identify system weaknesses and risks that are tied to a specific resource type. ERCOT's Seasonal Assessment of Resource Adequacy (SARA) provides three scenarios that examine a combination of typical and extreme load conditions, unplanned outages, and wind and solar output (**Table 9**). Beginning with the approach discussed in Part IV, the SARA report relies on seasonal projections for resource capabilities and normal peak demand forecasts. Using those inputs, scenarios are added to incorporate historic extreme load conditions and resource performance during tight operational periods to illuminate a range of resource adequacy outcomes based on different assumptions for varying system conditions.

Table 9: ERCOT's Summer 2023 SARA Extreme Reserve Capacity Risk Scenarios (ERCOT, 2023)

	Extreme Peak Load / Typical Unplanned Outages / Typical Wind and Solar	Extreme Peak Load / Extreme Unplanned Outages / Typical Wind and Solar	High Peak Load / Extreme Unplanned Outages / Extreme Low Wind
Scenario Adjustments			
[a] Peak Load Forecast (Baseline)	82,739	82,739	82,739
[b] Rooftop PV Forecast Reduction, MW	(432)	(432)	(432)
[c] Large Flexible Load Adjustment, MW	1,105	1,105	1,105
[d] Adjusted Peak Load Forecast, [a+b+c]	83,412	83,412	83,412
[e] Total Resources (from Forecast Capacity tab)	96,988	96,988	96,988
Uses of Reserve Capacity			
High/Extreme Peak Load Adjustment	5,114	5,114	3,389
Typical Planned Outages, Thermal	59	59	59
Typical Unplanned Outages, Thermal	4,975	4,975	4,975
Extreme Unplanned Outage Adjustment, Thermal	-	6,173	6,173
Extreme Low Wind Output Adjustment to 61 MW	-	-	10,366
[f] Total Uses of Reserve Capacity	10,148	16,321	24,962

NERC's summer and winter reliability assessments include a "seasonal risk scenario" for each area: a deterministic analysis that presents the extreme demand forecast and expected operating reserve requirement, as well as different levels of resource availability (**Figure 15**). Utility regulators or system planners in each assessment area can modify the scenario by incorporating different inputs to illustrate their unique system risks based on the area's resource mix and historic generator performance data (i.e., forced outage rates).

Figure 15: NERC's Seasonal Risk Scenario (NERC, 2020)



For illustrative purposes only

As extreme weather events impact grid reliability, it is important to capture these vulnerabilities in future assessments. Scenario assessments have been used for decades and continue to be an informative tool that can help demonstrate system vulnerabilities during tail-end and high-impact, low-probability events. These analyses, particularly when developed with stakeholder input and thoughtful assumptions, ultimately paint a more complete picture of a system's ability to withstand extreme weather events.

Additional Information on Resource Adequacy Reforms & Alternative Methods

- *Redefining Resource Adequacy for Modern Power Systems* – Energy Systems Integration Group (Link)
- *Reforming Resource Adequacy Practices and Ensuring Reliability in the Clean Energy Transition* – Resources for the Future (Link)
- *Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation* – Energy Systems Integration Group (Link)
- *Reforming Resource Adequacy Practices and Ensuring Reliability in the Clean Energy Transition* – Resources for the Future (Link)
- *NERC's Seasonal and Long-Term Reliability Assessments* – North American Electric Reliability Corporation (Link)
- *The Basics of Essential Reliability Services* – North American Electric Reliability Corporation (Link)
- *A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems* – Lawrence Berkeley National Laboratory (Link)
- *Resource Adequacy for a Decarbonized Future: A Summary of Existing and Proposed Resource Adequacy Metrics* – Electric Power Research Institute (Link)

Regulatory Considerations for Extreme Weather Events

Power systems have always been influenced by the weather with varying geographic exposure to varying types of natural disasters. According to ESIG, "while historical resource adequacy analysis focused on probabilities of discrete independent mechanical or electrical failures, weather-influenced correlated events should now be recognized as a driving factor of reliability (ESIG 2021)." Weather-related system outages caused by widespread and prolonged heat waves, extreme cold temperatures, or severe storm systems between 2011 and 2021 increased by roughly 78%, compared to 2000-2010.[36] The Electric Power Research Institute (EPRI) further reports that "extreme weather events are rising in frequency, intensity, geographic scope, and duration; the impact of weather is non-linear and rising much faster than frequency; a ten-year historical calculation of extreme event probability understates the likelihood of an extreme event in a changing climate (EPRI, 2021)." Recent load-shed events in California (August 2020) and Texas (February 2021) demonstrated how extremeweather events can reveal grid vulnerabilities that lead to catastrophic outcomes.

System reliability and resilience can be examined through performance metrics on the distribution or bulk power systems. The bulk power system (including transmission and large generators) operated 99.4% of the year without operator-initiated firm load shed in 2022, according to NERC (NERC, 2023). The Department of Energy further indicated in their 2017 Quadrennial Energy Review that over 90% of all customer outages disproportionately occur from disruptions on the distribution system, which largely falls within the regulatory

36 Climate Central analyzed U.S. power outage data between 2000 and 2021, as submitted by utility companies to the federal government and NERC. Major power outages described in this report are large electrical disruptions during which at least 50,000 customers lost power.

oversight of state commissions.[37] Most of these outages were caused by local or widespread weather-related events (DOE, 2017). The distribution system is inherently more vulnerable to outages-particularly during extreme weather events, with 5.5 million miles of distribution lines, most of which are above ground and exposed to outages, compared to about 700,000 circuit miles of transmission (NAE, 2018).

As state utility regulators navigate investment decisions to address the potential impacts of extreme weather events on their respective systems, it's important to distinguish between reliability and resilience in the context of system planning and cost recovery. Different resources bring different capabilities, along with potential system vulnerabilities, as highlighted in **Table 7** and **Table 8** of the previous subsection (NREL, 2020). A more robust understanding of the limitations of a resource mix can help utility regulators plan for the associated risks with the changing frequency, intensity, geographic scope, and duration of extreme weather events.

Identifying System Vulnerabilities

Although regional heatwaves have caused energy emergency alerts (EEAs) and periods of tight conditions in Texas, the mid-Atlantic, and other parts of the country during the past decade, only the 2020 heat wave resulted in firm load shed on the CAISO system. It is evident that electric system outages throughout the country are occurring more frequently during the winter season, with five major winter outage events during the past 11 years (S&P, 2023). In their aftermath, these events reveal opportunities for system planners, operators, resource owners, and utility regulators to modernize resource adequacy and resilience approaches used to inform the investment decisions of regulated utilities. In addition to the lessons-learned from these specific events, state utility regulators should also consider the broader contributing factors toward increased system outages during extreme weather events:

- The 140-year buildout of the U.S. electrical system was developed as a patchwork of infrastructure that varies in age, ownership, and levels of maintenance investments. This paradigm continues today, which can create hidden vulnerabilities that are often exposed by extreme weather events.
- The establishment and expansion of larger RTOs and reserve sharing groups led to more efficient regional planning processes, which reduced excess planning reserves. These trends, combined with the additional resources with energy-limited attributes or just-in-time fuel delivery requirements, contributed to less resilient performance during extreme weather events.
- During the last 50 years, both distribution and bulk power systems have expanded with population growth, covering a larger geographic footprint, resulting in more significant impacts during extreme weather events. Moreover, the system has grown with more resources and line miles, increasing the potential for vulnerabilities.
- The shift from coal-fired to gas-fired capacity created interdependencies with higher potential for correlated generator outages (i.e., common-mode failures) due to interruptions on the gas pipeline system (ESIG, 2021).
- Natural gas generation is increasingly used as "baseload" instead of "peaking" resources. As a result, disruptions to the delivery of natural gas (e.g., the loss of a single component on the natural gas system), which exposes gas-fired generators to a higher level of risk (NERC, 2017).
- Increased reliance on natural gas generators creates two supply risks: 1. fuel interruptions related to the type of delivery contract (i.e., firm vs. non-firm); 2. curtailment risks, which occurs when the delivery of natural gas—including customers with "firm" service—are disrupted through a force majeure event.

37 A "Brightline" threshold of 100kv or above is considered part of the Bulk Electric System, subject to NERC Reliability Standards, including Reliability Standards that require clearance of vegetation management under high-voltage transmission lines. This is not required on low-voltage lines, which can lead to more outages caused by fallen trees on the distribution system.

- The technology used in newer gas turbines is more sensitive to ambient temperatures, resulting in larger derates during periods of extreme heat or cold (ESIG, 2021).
- Cold weather events were relatively rare in historically warmer, summer-peaking systems. However, these cold weather events are occurring more frequently, even when the area reports higher planning reserve margins for the winter season (more available capacity).[38] Resources in warmer regions are generally designed to optimize performance during high-temperature conditions. This creates complexity for utility regulators in determining the appropriate level of investment to strategically winterize or protect vulnerable resources, considering that the frequency of these extreme events seem to be changing (ESIG, 2021).
- Resource adequacy assessments currently lack information that provide useful representations of weather dependencies and weather data, creating incomplete information (Carvallo, 2023).

State Legislative Action and Regulatory Responses to Extreme Weather Events

State utility regulators and utility planners have relied on historical information when analyzing future system risks and reviewing proposed utility plans to address them. If severe weather and the associated system impacts are rapidly changing, then past data, including load forecasts and forced outage rates for generators, may not be as dependable. Additional tools, including climate models, extreme load forecasts (e.g., 90/10 load forecast scenarios), and system risk scenarios will provide additional insights so that utility regulators can have a more holistic understanding when reviewing proposed utility plans. Reliability assessments need to be adapted to better capture a climate future with less certainty.

The monetary tradeoff between pre-event preparation and post-event mitigation is a complicated equation, since nearly all economic activity is halted during electricity service interruptions—particularly longer-term (4+ hour) outages and extended outages that can lead to loss of life (Holmgren, 2007). Electrical outages have additional impacts on the availability of other utility sectors and services, including telecommunications, water, and natural gas delivery systems.

State utility regulators are exploring how to appropriately invest in cold-weather protection features so there are enough resources available to reliably operate under more frequent periods of extreme cold temperatures. Most commissions have the authority to encourage or even require more robust utility planning processes through investigations and convening stakeholders to discuss potential implementation of new technologies, planning approaches, other strategies to address electric system vulnerabilities. In their prudent review of proposed utility investments, commissioners can consider the extent to which utilities incorporate extreme weather into their resource plans. Or if utilities are including climate modeling in their load forecasts.

To effectively navigate the complexities of making resilience investments, some public utility commissions have required the utilities they regulate to conduct climate threat assessment modeling, particularly where states require integrated resource planning. Climate threat assessment modeling involves hazard identification, exposure analysis, evaluating, modeling, and forecasting the threats posed by climate change to public utility infrastructure, ecosystems, and the communities they serve. The staff expertise at many utility companies typically does not extend to modeling of complex weather inputs or climate-related threats. However, many resources and tools are available to utilities, state energy offices, and state commissions, while many others are still in development. As utilities leverage advanced modeling techniques and data-driven analysis, utilities and public utility commissions can gain critical insights into the potential impacts of climate change on public utility infrastructure, empowering them to make informed decisions and develop robust adaptation strategies. Through scenario-based projections and probabilistic assessments (discussed in the previous subsection), utilities can prioritize investments and infrastructure improvements to effectively

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38 Notable cold weather events include: 2011 Southwest Cold Weather Event; 2014 "Polar Vortex" event, impacting the Midwest, South Central, and East Coast regions; the January 2018 South Central Cold Weather Event; and Texas' Winter Storm Uri in 2021.

allocate resources and minimize potential disruptions. Scenarios, cost-benefit analysis, and more complete understanding of system vulnerabilities will allow state commissions to identify more appropriate cost recovery approaches for resilience investments.

The inclusion of climate vulnerability assessments and climate mapping and cost recovery in commission seems to be increasing, according to a 2023 report released by the Pacific Northwest National Laboratory (PNNL), which documents several recent examples in several states. According to the report, "if regulatory bodies set clear goals and expectations, but utility investments are not vetted through a climate adaptation process, those investments could be at risk in a future prudence review (Homer et al., 2023)." Although climate modeling may be imprecise in predicting specific extreme weather events, including these insights in utility system planning and operational practices can provide a valuable understanding of the potential threats faced by vulnerable systems. EPRI notes that moving "from the current status-quo to fully climate-informed models that aid in resilience characterization and adaptation prioritization is nontrivial and requires integrating many disciplines and research approaches across both the planning and operational horizons within a company (EPRI, 2023)." PNNL has identified states that have introduced various forms of climate-orresilience-related requirements (**Table 10**).

Table 10: List of State Requirements for Climate-Related Processes (Homer et al., 2023)

Climate-Related Process	California	Connecticut	D.C.	Florida	Hawaii	Louisiana	Maryland	Massachusetts	Michigan	Nevada	New Hampshire	New York	New Jersey	North Carolina	Oklahoma	Oregon	Pennsylvania	Rhode Island	Texas	Utah	Washington
State-level planning requirements																					
Requirement for climate vulnerability assessment and mitigation plans	•											•									
Requirement for storm management plans				•																	
Requirement for wildfire mitigation plan[1]	•									•						•				•	○
Requirement to consider climate change in distribution system planning									○												
Settlement agreement requires climate vulnerability assessment														•							
Resilience actions tied to cost recovery																					
Grid hardening or storm management actions tied to cost recovery surcharge		•	•		•	•	•	•			•		•	○	•		•	•	•		

• is used to indicate the statutory or legislative requirement exists, or utilities voluntarily developed the plans indicated.

○ is used to indicate that dockets are open in which the objective would apply.

[1]States apply several names, e.g., resource protection plans, but wildfire mitigation is a major part of such alternative plans.

Additional information on some of these state efforts and initiatives are provided below.

California: The California Public Utilities Commission (CPUC) introduced a 2020 order requiring regulated IOUs to conduct climate vulnerability assessments in four-year increments coincident with general rate case proceedings (CPUC, 2023). The CPUC ruling also directed special attention to the climate vulnerabilities and potential adaptation measures in historically disadvantaged communities. These assessments will directly tie utility resiliency investments to mitigating impacts from climate vulnerabilities. The regulated investor-owned utilities in California are expected to begin filing those plans in late 2023 and 2024. Additionally, the CPUC has required their utilities to include an iteration of climate vulnerability mapping as one of the ten categories of potential mitigation strategies required to be included in utility wildfire mitigation plans (California, 2021).

Florida: The Florida Public Service Commission requires utilities to develop storm protection plans and demonstrate their ability to enable the electric grid to withstand and recover from hurricanes and tropical storms (FPSC, 2018). These planning approaches strategically focus on climate change impacts, address cost recovery concerns, and identify high-risk investments.

Michigan: An extreme cold weather event in late-2019 caused an energy emergency in Michigan, challenging the state's natural gas and electric systems. After the event, the governor requested that the Michigan Public Service Commission (MPSC) conduct a Statewide Energy Assessment to:

1. evaluate whether the design of electric, natural gas, and propane delivery systems are adequate to account for changing conditions and extreme weather events; and
2. provide recommendations to mitigate risk. The MPSC responded by opening a case to evaluate whether the electric distribution system is designed to account for changing climate conditions and extreme weather events. The resulting report developed into several proceedings under the auspices of the 2019 Michigan Statewide Energy Assessment (MPSC, 2019).

New York: In 2022, the governor signed a law act requiring utility corporations to submit a climate vulnerability study, evaluating each electric corporation's infrastructure exposure to climate risks. The act also requires each utility to file a subsequent climate vulnerability and resiliency plan to address the results and conclusions of the initial study (NYDPS, 2022).

Louisiana: The Louisiana Public Service Commission staff proposed rulemaking on requiring electric utilities to file a 'Grid Resilience Plan' with the commission that contains an all-hazard risk assessment, including climate risks (LPSC, 2021; LDSC, 2023).

Texas: In the aftermath of Winter Storm Uri (February 2021), the Public Utility Commission of Texas (PUCT) responded to legislative directives through Case 53401-39, a filing to electric weather preparedness standards (PUCT, 2022). The Texas legislature subsequently passed a law requiring electric utilities to file a 'resiliency plan' with the PUCT that addresses at least one of climate-related threats (Texas State Legislature, 2023).

State utility regulators will continue to play an important role in responding to state legislatures and implementing various actions to address extreme weather events. This includes modified or new approaches for the review and approval of related utility investments that balance costs and risks. The establishment of clear goals, expectations, and metrics can support prudent utility investments and reduce utility concerns about cost recovery (Homer et al., 2023). Potential approaches include:

- Supporting electric utilities with identifying and prioritizing investments that provide climate resilience.
- Coordinating investigations and convening stakeholders to discuss what utilities should do to prepare the electric system for extreme weather events and broader impacts of changing climate.
- Setting clear goals and expectations in cases where utilities are required to file risk-specific mitigation plans or linking identified grid investments with favorable cost recovery mechanisms (e.g., cost riders).

Other Planning Strategies and Industry Recommendations to Address Extreme Weather Events

System vulnerabilities are being addressed through a variety of forums with utility, state, and federal regulatory involvement. Many of these efforts have resulted in recommendations that are summarized below.

ESIG's 2021 Task Force on Redefining Resource Adequacy (and corresponding report), identified the following strategies to improve system planning and modeling for extreme weather events:

- **Chronological Operations Must Be Modeled Across Many Weather Years:** A simple planning reserve margin that is used to procure a certain amount of capacity above and beyond peak load does not ensure that the system will be reliable during other times of the year given changes in the resource mix. Chronological operations and scheduling ensure that energy storage and demand response will be around long enough, and can fully recharge, to support the system through reliability challenges.
- **The Need for Many Years of Weather Data:** Resource adequacy analysis for modern power systems requires the incorporation of many years of weather data. Many years of synchronized hourly weather and load data are necessary to understand correlations and interannual variability between wind and solar generation, outages, and load. Using stochastic production cost methods—combining both chronology and varying weather across a full 8,760-hour analysis—is necessary to help identify times and situations of peak risk. Given that low-probability events drive resource adequacy challenges, a long historical record of weather data is necessary to identify the probability of potential extremes.
- **Recognizing the Unique Weather-Dependent Operational Characteristics of All Resources:** Future resource adequacy analysis should explicitly recognize that all resources have limitations based on weather-dependence, potential for outages, flexibility constraints, and common points of failure.
- **Neighboring Grids and Transmission Should Be Modeled as Capacity Resources:** Resource sharing can be a significant, low-cost alternative to procuring new resources. Imports from neighboring regions are likely to become more valuable for resource adequacy due to the increased diversity of resource sharing can be a significant, low-cost alternative to procuring new resources. Imports from neighboring regions are likely to become more valuable for resource adequacy due to the increased diversity of chronological wind, solar, and load patterns over a much larger area. While extreme weather can happen anywhere, it does not happen everywhere at once.

The North American Energy Standards Board's (NAESB) 2023 Gas-Electric Harmonization Forum Report offered several recommendations for state utility regulators to address extreme weather-related challenges, provided below:

- **Recommendation 7:** State public utility commissions and applicable state authorities in states with competitive energy markets should engage with producers, marketers, and intrastate pipelines to ensure that such parties' operations are fully functioning on a 24/7 basis in preparation for and during events in which extreme weather is forecasted to cause demand to rise sharply for both electricity and natural gas, including during weekends and holidays. (States could consider the approaches adopted in FERC regulations affecting the interstate pipelines.) In instances where state authorities lack enabling authority to take such actions, the FERC should adopt regulations to achieve identical outcomes within its authority.
- **Recommendation 10:** State public utility commissions should encourage local distribution companies within their jurisdictions to structure incentives for the development of natural gas and electric demand-response programs in preparation for and during events in which demand is expected to rise sharply for both electricity and natural gas.
- **Recommendation 12:** Joint and cross-market, long-term planning should be expanded by relevant gas and electric market parties with an increased focus on fuel adequacy. FERC should encourage this planning coordination using its oversight roles for interstate pipelines, regulated RTO/ISO interstate transmission, and Electric Reliability Organization (ERO)-related Planning Authorities and collaborate with state public utility commissions and applicable state authorities.
- **Recommendation 13:** The FERC, state public utility commissions, and applicable state authorities in states with competitive energy markets should consider whether market mechanisms are adequate to ensure that jurisdictional generators have the necessary arrangements for secure firm transportation and

supply service and/or storage to avoid and/or mitigate natural gas supply shortfalls during extreme cold weather events, and if not, (a) determine whether non-market solutions are warranted, including funding mechanisms borne or shared by customers and (b) if warranted, adopt such non-market solutions.

- **Recommendation 14:** Applicable state authorities should consider the adoption of legislation or regulations or other actions to create a secondary market for unutilized intrastate natural gas pipeline capacity, including a requirement for intrastate pipelines to offer some minimum level of firm service and/or support bilateral agreements between end users. In instances where state authorities lack enabling authority to take such actions, the FERC should adopt regulations to achieve identical outcomes within its authority.
- **Recommendation 15:** Applicable state authorities should consider establishing informational posting requirements for intrastate natural gas pipelines to enhance transparency for intrastate natural gas market participants regarding operational capacity data, similar to the reporting and posting requirements mandated by the FERC for interstate natural gas pipelines as part of 18 CFR §284.13.
- **Recommendation 16:** Applicable state authorities should consider the development of weatherization guidelines appropriate for their region/jurisdiction to support the protection and continued operation of natural gas production and processing and gathering system facilities during extreme weather events and require public disclosure concerning weatherization efforts of jurisdictional entities.

Additional Information on Regulatory Considerations for Extreme Weather Events

- Emerging Best Practices for Electric Utility Planning with Climate Variability: A Resource for Utilities and Regulators – PNNL (Link)
- Gas Electric Harmonization Forum Report – NAESB (Link)
- Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System – NERC (Link)
- Root Cause Analysis: Mid-August 2020 Extreme Heat Wave – CAISO (Link)
- The February 2021 Cold Weather Outages in Texas and the South Central United States – s FERC, NERC and Regional Entity Staff Report (Link)
- Winter Storm Elliott Public Report – ERCOT (Link)

The Interplay between State Resource Planning & Regional Reliability

Resource adequacy is an important driver in state regulatory decisions. When a commission reviews a utility rate case with proposed resource decisions (e.g., plans to procure/construct generators or retire existing ones), the regulatory approval process discussed in Part II is usually informed by a series of factors. Among them are customer affordability (just and reasonable rates), alignment with state policy goals, and potential impacts to system reliability. These impacts are modeled and examined within a utility's service territory, which is where a commissions direct authority ends. Similarly, transmission planning is critical to support a reliable system. Interregional transmission can provide operating flexibility to import power where it is needed most during potential energy shortages. State, local, and individual utility policies aimed at a carbon-free generation mix can impact regional reliability, particularly since the electric systems are not based on political boundaries. Moreover, state renewable portfolio standards and clean energy standards create different qualifying resources and requirements related to serving in-state electricity needs by a specified year, potentially impacting export capabilities to neighboring states. In addition, new transmission is critical to supporting state clean energy goals, where it is necessary to import renewable energy from remote sources to load centers.

State Forums for Regional Resource Adequacy Coordination

The topic of resource adequacy usually extends beyond state borders, as demonstrated by the regulatory oversight authorities and activities discussed in Section II. Reliability issues, regional transmission planning efforts, and system impacts of individual state energy policies can be effectively coordinated through formalized regulatory engagement with system planners and operators. Single-state RTOs, including California, New York, and Texas, have a more simplistic governance process for commission engagement and participation. In multi-state RTOs, the establishment of regional state committees (RSC) allow commissions from multiple states to participate in a coordinated stakeholder process (NARUC, 2022). RSCs have been formed in four RTOs and include representation from utility regulators and/or policy makers from member states and allow the ability to provide combined feedback to their respective RTOs and FERC.

The roles of individual states and RSCs in influencing resource adequacy decisions vary across multi-state RTOs (Chen and Murnan, 2023). In multi-state regions with organized markets, state utility regulators often align resource planning processes with the resource adequacy frameworks and requirements established by the ISO/RTO and approved by FERC. According to governance processes across four RSCs, SPP and MISO allow for more state input in resource adequacy decisions. For example, Southwest Power Pool's Regional State Committee can determine the region's approach for ensuring that the resource mix adequately supports reliability (NESCOE, 2022). Similarly, individual states with regulated utilities participating in the MISO market maintain the power to override the regional target for resource procurement in their respective jurisdictions. Alternatively, states in ISO-New England are more constrained in their ability to influence regional reliability, limited to a single collective vote (representing six states) when approving the region's target reserve margin. States have no formal role in PJM's resource adequacy decisions.

As states implement RPS goals, clean energy standards, or other policy goals, it is important that forums allow for coordination in multi-state RTOs. A list of forums for each area is provided in **Table 11**, with additional information below, detailing the governance structure and practices of RSCs and other forums for state engagement on resource adequacy issues in systems throughout the U.S.

California ISO

The California Public Utilities Commission (CPUC) represents the state's interests in conjunction with the California Energy Commission (CEC). Like other state commissions, the CPUC maintains responsibility over resource adequacy. Transmission planning in California follows the same open-meeting format and process as other initiatives, with the CPUC and CEC participating as stakeholders, providing input on resource adequacy assumptions (resource mix and load projections), and identifying reliability-driven transmission solutions (Parent et al., 2021).

Electric Reliability Council of Texas

ERCOT is governed by an independent board of directors and subject to oversight by the Public Utility Commission of Texas (PUCT) and the Texas legislature. The PUCT maintains jurisdiction over activities conducted by ERCOT and performs regulatory functions for electric transmission and distribution utilities across the state. Vertically integrated electric utilities within Texas, but outside of the ERCOT system, are also regulated by the PUCT. ERCOT's Regional Planning Group (RPG) is a stakeholder forum for input on issues related to planning the ERCOT system for reliable and efficient operation. ERCOT staff leads the RPG, and membership is open to all market participants, transmission and distribution service providers, and other stakeholders. This group is also open to participation from PUCT staff. Members provide input into annual and special planning studies, review proposed transmission projects, and provide comments to inform ERCOT's independent review of projects. On November 3, 2022, the PUCT issued an order directing ERCOT to assume the duties and responsibilities of the Reliability Monitor for the Texas power grid (PUCT, 2022). ERCOT, acting as the Reliability Monitor, gathers and analyzes information and data to meet its monitoring obligations as required by 16 TAC § 25.503(k), under the direction of the PUC (ERCOT, 2022).

Table 11: ISO/RTO or Regional State Resource Adequacy Forums

Area / System	Forum(s) for State Participation
California ISO	Commission and energy office engage in ISO stakeholder processes
Electric Reliability Council of Texas	• Regional Planning Group (RPG) and other committees and working groups
ISO-New England	• New England Conference of Public Utility Commissioners (NECPUC) • New England States Committee on Electricity (NESCOE) • ISO-NE Planning Advisory Committee
Midcontinent ISO	• Organization of MISO States (OMS) • Direct commission engagement
New York ISO	• Commission involvement with ISO stakeholder processes • New York State Reliability Council (NYSRC)
PJM Interconnection	• Organization of PJM States, Inc. (OPSI) • Independent State Agencies Committee (ISAC) • Direct commission engagement with PJM
Southwest Power Pool	• SPP Regional State Committee (RSC) • Cost Allocation Working Group • RSC/OMS Liaison Committee • Direct commission engagement with SPP
Southeast (Non-Market)	• SERC's Resource Adequacy Working Group (RAWG) and other regional groups allow for commission engagement
Western Interconnection (Non-Market)	• Western Resource Adequacy Program (WRAP) • Western Electricity Coordinating Council (WECC) • Western Interconnection Regional Advisory Body (WIRAB) • Committee on Regional Electric Power Cooperation (CREPC)

In 2021, the Texas Legislature reaffirmed the Commission's complete authority over ERCOT and made fundamental changes to ERCOT Inc. governance in Senate Bill (SB) 2. Specifically, SB 2 restructured the ERCOT Board of Directors to be comprised only of independent board members appointed by a selection committee and subject to specific qualifications (PUCT, 2023).

ISO-New England

ISO New England (ISO-NE) plans and operates the transmission system and administers the wholesale electric power markets across the six New England states. There are two primary forums where state commissions can collaborate to discuss regional topics related to electricity planning:

- **New England Conference of Public Utility Commissioners (NECPUC):** The board of directors includes a commissioner from each New England state. Individual state commissions, and NECPUC as their collective representative, engage directly in the regional stakeholder process.
- **New England States Committee on Electricity (NESCOE):** A not-for-profit entity that represents the collective perspective of the six New England Governors in regional electricity matters and advances the

New England states' common interest in the provision of electricity to consumers at the lowest possible prices over the long-term, consistent with maintaining reliable service and environmental quality. The committee is governed by a board of managers appointed by the governor of each state. NESCOE advocates for the common interests of all six states on consumer issues and energy policy goals. NESCO also examines resource adequacy and system planning issues, providing consolidated input to the ISO-NE on planning and/or market design.

NESCOE, NECPUC, and individual state entities participate in ISO-NE's various stakeholder processes and committees, including the Planning Advisory Committee. NESCOE and NECPUC coordinate to avoid duplicative efforts and Both groups hold semiannual meetings with the ISO-NE Board of Directors to discuss regional electricity issues.

Additionally, the New England Power Pool (NEPOOL) has over 500 members with diverse and varied interests. Its members include not only entities that own and operate bulk power facilities, but many others who are tasked specifically to represent the interests of consumers broadly, including over 50 consumer-owned utility systems, public interest groups, the offices of public advocates from four of New England's six states (Connecticut, Maine, Massachusetts and New Hampshire), and end-use consumers themselves. NEPOOL members align with one of six sectors.

Midcontinent ISO

The Midcontinent Independent System Operator (MISO) operates the transmission system and oversees the wholesale power market for portions of 15 states in the midwestern and southern United States. State commissions participate and provide input to MISO's processes through participation in the Organization of MISO States (OMS). MISO specifically defines how state commissions and the OMS can participate in their governance structure (Parent et al., 2021).

The OMS is an autonomous and self-governing organization that serves as a forum for state regulatory authorities to coordinate on MISO-related initiatives, including stakeholder processes.[39] The OMS was established to represent the collective interests of state and local utility regulators in the MISO region and facilitate informed and efficient participation in related issues. Members collaborate to share information and resources, debate and exchange ideas on policy issues, and communicate their viewpoints. While the OMS strives for agreement, each member retains absolute autonomy to express its unique positions and be heard through OMS comments and filings.

The OMS can prepare formal recommendations to the MISO Board or FERC related to how market design or other policies impact state interests. The OMS Board of Directors is comprised of one designated commissioner from each state[40] The OMS addresses a wide array of topics, including reliability, resource adequacy, and transmission planning. Under certain circumstances, the OMS can file an alternative transmission cost allocation approach under Section 205 of the Federal Power Act.[41] The OMS Board designates four commissioners to represent state interests on the Advisory Committee, which serves as a forum for stakeholders to provide input and recommendations to the MISO Board.

New York ISO

The New York Independent System Operator (NYISO) operates the transmission system and oversees the wholesale power market for the State of New York. The New York Public Service Commission (NYPSC), an agency within the state's Department of Public Service, is engaged in the governance structure and practices

39 The OMS has the same rights as MISO members that participate in the stakeholder process.

40 The OMS Board also includes representatives from the City of New Orleans, and the Province of Manitoba for a total of 17 directors.

41 With support of at least 66% of the OMS Board, OMS can request that MISO file under Section 205 of the Federal Power Act an alternative transmission cost allocation approach when MISO plans to propose and file a new, or amend an existing, transmission cost allocation methodology.

of NYISO, permitted to engage in all stakeholder processes in the same manner as a non-voting NYISO member. However, the NYPSC and NYDPS are not allowed to appeal items to the NYISO Board or Management Committee.

The New York State Reliability Council (NYSRC) is governed by the Executive Committee, comprised of 13 members from various sectors, and is responsible for maintaining the state's reliability rules and holds authority to audit NYISO's implementation and compliance with those rules. The most critical state reliability rule is the establishment of the system's installed capacity requirement and associated reserve margin for the New York control area (NYSCR, 2020). The NYPSC and NYDPS participate in the NYSRC's stakeholder processes.

Transmission planning projects within the state can be designated by the NYPSC as public policy-driven projects that employ a specific cost allocation approach. The PSC can further propose the specific method used, potentially through collaborating with the project developer (NYISO, 2023).

NYISO, on behalf of the PSC or the transmission developer in collaboration with the NYPSC, can submit a Section 205 filing on the proposed cost allocation approach. The NYSRC also maintains the right to file the system installed capacity requirement with the FERC under Section 205, but does not determine local installed capacity requirements, which is under the purview of the NYISO (NYSRC, 1999).

PJM Interconnection

The PJM Interconnection (PJM) is the largest ISO/RTO (in terms of energy consumption) in United States, with service territory covering all or part of 13 states and the District of Columbia.

PJM manages an Independent State Agencies Committee (ISAC), a voluntary, stand-alone committee that consists of members from regulatory and other state agencies representing all of the states and the District of Columbia within the service territory of PJM. The ISAC is an independent committee that is not controlled or directed by PJM, the PJM Board of Managers or PJM members. The purpose of the ISAC is to provide PJM with inputs and scenarios for transmission planning studies except public policy requirements, which are provided individually by the state.

While PJM maintains a shared governance structure with the PJM Board of Managers and various Members Committees, state commissions provide feedback to PJM through a separate stakeholder process. Participants in this process include the Organization of PJM States, Inc. (OPSI), a liaison group comprised of representatives from all state commissions that regulate utilities within PJM's territory. OPSI engages with PJM, the PJM Board, the Independent Market Monitor, the FERC, and other agencies. OPSI participates in PJM's stakeholder processes, along with individual state commissions, and can raise issues and present proposals for consideration. These processes may be related to resource adequacy, transmission planning, and the impacts of state energy policies. OPSI meets at least once each year with the PJM Board to discuss relevant topics of interest (OPSI, 2005).

Southeast (Non-Market)

SERC is a voluntary membership corporation, separate and distinct from the mandatory registration and certification required for certain bulk power system owners and operators. Membership is voluntary, free of charge, and open to entities within or outside of the mandatory compliance footprint that meet the eligibility requirements. Members can provide input on vital matters and decisions through various SERC forums, including technical committees and working groups.

One such working group includes SERC's Resource Adequacy Working Group (RAWG). Here, the group members perform studies to determine reliability metrics for resource planning and engage in dialogue that provides a higher visibility of regional risk to the bulk power system. The SERC Probabilistic Assessment study is a product of the RAWG and highlights regional resource risk, the dependence on regional transfers, and overall

SERC region resource adequacy. It supplements the SERC Long-Term Reliability Assessment study. Additional studies may be performed by the RAWG with input from the SERC Engineering Committee, Planning and Coordination Subcommittee, and Reliability Risk Working Group. This committee supports SERC's mission and vision by projecting resource adequacy risk and driving planning efforts to reduce risk.

Southwest Power Pool

The SPP operates the transmission system and oversees the wholesale power market across parts of 14 states in the central part of the U.S. The RTO has a "shared governance structure" in which the SPP Board of Directors (SPP Board) and SPP Regional State Committee (RSC) share decision-making responsibilities (Parent et al., 2021). State regulatory authorities are included in the governance structure through both the SPP RSC and the direct participation or engagement of individual state commissions in SPP processes. The SPP RSC is comprised of commissioners from each state in the SPP territory and provides collective state commission input on matters of regional importance related to the development and operation of bulk electric transmission. The Cost Allocation Working Group reports to the SPP RSC, addressing matters related to transmission planning, cost allocation, and resource adequacy (SPP, 2023).

The SPP - RSC/OMS Liaison Committee was formed in recognition of ongoing issues preventing efficient economic transmission planning, market and operations, and resource integration along the SPP-MISO seam. A liaison committee was formed by the boards of the OMS and the SPP RSC to facilitate identification of issues and potential solutions to enhance the benefits to customers from better coordinated seams policies (SPP, 2023). For transmission planning in SPP, the RSC has a defined role and works closely with transmission owners to develop the regional system plan with a particular focus on transmission cost allocation.

Western Interconnection (Non-Market)

Aside from utility IRPs overseen by state commissions, other forums in the west create opportunities for utility regulators, state energy offices, and others to engage in separate resource adequacy-related studies and processes. Those forums are provided below:

- **Pacific Northwest Utilities Conference Committee (PNUCC):** This committee is comprised of investor-owned utilities, consumer-owned utilities, and independent power producers. PNUCC develops an annual Northwest Regional Forecast, which includes an analysis of resource adequacy studies prepared throughout the region (PNNUC, 2021).
- **Northwest Power and Conservation Council (Council):** The Council was established by the 1980 Northwest Power Act to prepare regional power plans for the four-state region of the Columbia River Basin (Montana, Idaho, Oregon, and Washington), as well as British Columbia, and Alberta. The Council's Resource Adequacy Advisory Committee publishes an annual Adequacy Assessment for the Northwest region.
- **The Western Electric Coordinating Council (WECC):** The WECC is one of six NERC Regional Entities that conducts resource adequacy analysis for balancing authorities, or groups of balancing authorities in the Western Interconnection. WECC promotes bulk power system reliability and security and is responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC creates a forum for the development of Regional Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC Bylaws (WECC, 2018). WECC oversees the largest and most geographically diverse region in the United States. Membership is open to all entities that meet the qualifications in the WECC Bylaws (WECC, 2018). WECC recently produced a Western Assessment of Resource Adequacy to complement NERC's Long-Term Reliability Assessment (WECC, 2021).
- **Western Interconnection Regional Advisory Body (WIRAB):** Following the petition of ten governors from western states, and in accordance with Section 215(j) of the Federal Power Act (FPA), FERC established WIRAB in 2006. WIRAB has the authority to advise FERC, NERC, and WECC on matters pertaining to

electric grid reliability (and potentially resource adequacy-related issues) in the Western Interconnection. Membership includes representation from western states and Canadian provinces that serve load in the Western Interconnection. WIRAB works to achieve member consensus before submitting advice on reliability matters (WEIB-WIRAB, 2023).

- **Committee on Regional Electric Power Cooperation (CREPC):** Initially established in 1982 as a joint committee of the Western Interstate Energy Board (WIEB) and the Western Conference of Public Service Commissioners (WCPSC), this committee is comprised of an energy office official and a regulatory utility commissioner from each of the states and provinces in the Western Interconnection.[42] The group works to examine electric power system policy issues that requires regional cooperation and coordination (WEIB-CREPC, 2023).
- **The Western Power Pool (WPP) and Western Resource Adequacy Program (WRAP):** The Northwest Power Pool (NWPP) was formed during World War II, when regional electric utilities and the Bonneville Power Administration pooled resources to support efforts during World War II (Kramer, 2010). It supports its members, to achieve the maximum benefits from coordinating the operations of their resources (NWCC, 2023). In 2023, FERC approved a tariff filed by the Western Power Pool (rebranded from the NWPP) to implement a Western Resource Adequacy Program (WRAP). Under this new paradigm, participating utilities will work to establish common resource adequacy standards and approaches (WPP, 2023). The WRAP currently offers an information-sharing forum that is non-binding. However, consideration is underway for potential binding tariff requirements for participating entities around a more formalized resource adequacy framework (WPP, 2023).

  The intent of WRAP is to ensure sufficient capacity among member utilities to meet a desired reliability standard. Two programs were established within the WRAP that require participating members to own or contract for sufficient capacity (and transmission for delivery) to meet their share of the collective reliability need:

  1. *The Forward Showing Program (FS Program):* a forward-looking resource adequacy compliance program that requires participating "Load Responsible Entities" (LREs)—utilities and other retailers—to procure resources to meet a defined compliance obligation using resource-counting rules established by the WPP.
  2. *The Operational Program (Ops Program):* an operations-focused capacity sharing program obligating WRAP members to hold back and share excess capacity during scarcity conditions. System conditions will be continuously reviewed for the upcoming seven days. In the event of a shortfall, members must facilitate bilateral transactions between participating entities at pre-established terms during the operational period.
- **Western Market Services:** In the absence of a western RTO, CAISO began offering grid services to other western states in 2014, while SPP followed five years later with the Western Energy Imbalance Service (WEIS) (SPP, 2022). Both RTOs have been expanding their grid services by providing load balancing services aimed at enhancing efficiency and reducing costs for their respective entities in the Western Interconnection. More recently, both RTOs are exploring voluntary day-ahead market services that would build on their current offerings. CAISO's final proposal for their Extended Day Ahead Market (EDAM), filed with FERC in August 2023, is designed to increase regional coordination, encourage the development of renewable energy resources, and lower costs for consumers. SPP is also proposing a day-ahead market, Markets+, which could be filed with FERC as early as the first quarter of 2024 (SPP,

42 The Western Interstate Energy Board (WIEB) is an organization of 11 Western States and 2 western Canadian Provinces. The Western Conference of Public Service Commissioners (WCPSC) is a regional association within the National Association of Regulatory Utility Commissioners (NARUC).

2022). These developments have the potential to impact other resource adequacy and system planning processes in the west.

Regional Impacts from State Resource Planning Decisions

Resource planning decisions for a single utility, or within a single state, will often have regional reliability implications. Energy serving load in one state is often imported from resources in a neighboring state, and in many cases, energy is supplied by entities that are not within the jurisdiction of a regulatory authority. Moreover, resource planning and related reliability across the system often require some level of regional coordination. This can be achieved without interfering with the autonomy of state legislatures and commissions as they advance individual energy policies. However, the impacts of these policies on neighboring states need to be carefully coordinated to avoid resource deficiencies. State utility regulators may wish to consider the following resource adequacy questions, among others, when examining individual utility IRPs within a region of diverse state clean energy policies (if applicable):

- How dependent is the utility's IRP on the imports needed to meet resource adequacy requirements?
- How will a state's exports be impacted by their own RPS requirements that may require the use of qualifying resources to serve local loads?
- How would a loss of imports impact compliance with the state's environmental policies?
- Do current in-state IRPs reflect the potential for changes to neighboring states RPS targets that may impact assumptions in the original IRPs?
- Is there potential for the introduction and/or modification of RPS and other clean energy standards in neighboring states that may impact the assumptions of existing in-state IRPs?
- How will state commissions track modifications to clean energy policies and requirements introduced by neighboring states in their respective interconnection and how will these developments impact transfer capabilities?
- How will a state with an RPS or clean energy standard or requirement address transfers of clean energy sources across the region in the interest of serving in-state load with qualifying resources?

Additional Information on State Resource Planning & Regional Reliability

- *Implications of a Regional Resource Adequacy Program on Utility Integrated Resource Planning* – LBNL (Link)
- *Regional Resource Adequacy* – California ISO (Link)
- *New England Conference of Public Utility Commissioners* (Link)
- *New England States Committee on Electricity* (Link)
- *ISO-NE Planning Advisory Committee* (Link)
- *Organization of MISO States* (Link)
- *New York State Reliability Council* (Link)
- *Organization of PJM States, Inc.* (Link)
- *SPP Regional State Committee* (Link)
- *SPP Cost Allocation Working Group* (Link)
- *Western Resource Adequacy Program* (Link)
- *Western Electricity Coordinating Council* (Link)
- *Western Interconnection Regional Advisory Body* (Link)

V. Resource Adequacy Approaches throughout the Country

This section is intended to provide a high-level explanation of how resource adequacy and system planning is conducted throughout the country. Each subsection was developed through coordination with state commissioners or staff from 15 states (at least one state commission provided input for each state/region). In some cases, additional input was provided from system operators. The intent of each subsection is to provide an overview of the entities involved in resource adequacy and planning, summarize various regulatory involvement in resource adequacy processes, and to highlight recent reforms and/or reliability issues in the area. These areas include:

- California ISO
- Electric Reliability Council of Texas
- ISO-New England
- Midcontinent ISO
- New York ISO
- PJM Interconnection
- Southeast (Non-Market)
- Southwest Power Pool
- Western Interconnection (Non-Market)

California ISO

Area Summary: The California ISO (CAISO) system is the largest of 38 balancing authorities in the Western Interconnection (35% of electric load). The CAISO is specifically responsible for system planning by conducting annual transmission planning processes and managing energy markets (day-ahead market, integrated forward market, and real-time market). The CAISO also performs system planning and resource adequacy studies and oversees stakeholder processes to improve market design. There are more than 150 core transmission and generation companies that are market participants. The CAISO is led by a Board of Governors who are appointed by California's governor. The CAISO also runs the Western Energy Imbalance Market (WEIM), which is discussed in more detail in the Non-Market Western Interconnection subsection.

State(s): 85% of California (and a small part of Nevada)

Regional Reliability Authorities: Western Electricity Coordinating Council (WECC)

State Commission(s): The California Public Utilities Commission (CPUC)

Forums for Regulatory Involvement: The California Public Utilities Commission (CPUC), the California ISO (CAISO), and the California Energy Commission (CEC) conduct close interagency coordination on grid planning and operational processes in addition to participating in each agency's respective proceedings.

Entities Involved in Resource Adequacy and Planning

The CPUC is the primary entity responsible for the state's resource adequacy program, which applies for the IOUs that represent approximately 85% of the state's load. This program establishes requirements for capacity procurement that each load-serving entity (LSE) must meet, as well as rules for counting resources towards those requirements. The identified resources must be made available to the CAISO market. California's infrastructure planning processes involve close collaboration with – and input from – the CAISO, the CPUC, and the California Energy Commission (CEC). The primary responsibilities of each entity are provided in **Table 12**.

Table 12: Primary Entities Involved in California's Resource Planning Processes

CPUC	CAISO	CEC	Jurisdictional LSEs
Manages the state's Integrated Resource Plan Proceeding (IRP). This process is designed to ensure that the electric sector meets its GHG reduction targets, while maintaining reliability (with a resource adequacy program) at the lowest possible cost. This process involves modeling the system topology and market dispatch results to determine the appropriate resource portfolio needed to meet policy goals. Develops and oversees the annual Resource Adequacy program, that is used to establish related obligations for jurisdictional LSEs.	Develops an annual Transmission Planning Process used to identify needed transmission upgrades and inform the CPUC's IRP process.	Develops long-term energy demand forecasts as part of their Integrated Energy Policy Report (IEPR). The CEC's IEPR demand forecasts are inputs into the CPUC's long-term resource planning process and the short-term annual resource adequacy process, used to establish related procurement obligations for LSEs.	Must submit individual IRPs (based on the parameters in the IRP) for CPUC review and approval. Must submit annual and monthly resource adequacy filings.

System-wide and local reliability requirements, as well as flexibility needs, are ultimately developed within the CPUC's Resource Adequacy Program (RA Program), for which the CPUC has ultimate jurisdiction. Established after the 2000-2001 California Energy Crisis, this program creates requirements for jurisdictional LSEs to procure and maintain resource availability through contractual obligations. The planning reserve margin (PRM) is a critical element of the resource adequacy program and is used to establish monthly requirements to ensure LSEs procure sufficient resources for the CAISO to reliably operate the system. The PRM targets also inform the CPUC's procurement decisions. In addition, the CAISO also has two separate stakeholder processes to modify their reliability backstop mechanisms, to be further discussed in the next section.

Resource Adequacy and System Planning Processes

California's Resource Adequacy program has two goals: 1.) Ensure the safe and reliable operation of the gridin real-time, providing sufficient resources to the CAISO when and where needed; and 2.) Incentivize the sitingand construction of new resources needed for future grid reliability.

The CPUC adopted a Resource Adequacy policy framework in 2004 that includes obligations applicable to all LSEs within the CPUC's jurisdiction. The commission's resource adequacy policy framework – implemented as the RA Program – guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO when and where needed. The RA Program codifies three distinct requirements, described in **Table 13**, with corresponding annual and monthly filings that are evaluated by the CPUC staff for accuracy and completeness.

Table 13: Resource Adequacy Requirements

Requirements	Inputs	Annual Filing	Monthly Filing
System RA	Each LSE and CEC-adjusted forecast, plus a 16% (2023) planning reserve margin.	LSE must demonstrate procurement of 90% of the obligation for the five summer months of the coming compliance year.	LSE must demonstrate procurement of 100% of their monthly obligation.
Local RA	Annual CAISO study (1-in-10 weather year and planning for the most stringent N-1-1 contingency, which is reviewed and adopted in the CPUC's resource adequacy proceeding).	For its three-year forward obligation, each LSE or Central Procurement Entity must demonstrate procurement of 100% of the obligation for each month of compliance years one and two and 50% of the obligation for year three. Beginning with the 2023 compliance year, Central Procurement Entities have assumed primary responsibility for local capacity procurement in the PG&E and SCE service territories.	In all months, each LSE must demonstrate compliance with 100% of their obligation. From July to December, each LSE must demonstrate procurement of their revised (due to load migration) local resource adequacy obligation. Beginning with the 2023 compliance year, Central Procurement Entities have assumed primary responsibility for local capacity procurement in the PG&E and SCE service territories.
Flexible RA	Annual CAISO study that examines ramping needs, which is reviewed and adopted in the CPUC's resource adequacy proceeding.	LSE must demonstrate procurement of 90% of their obligation for each month of the coming compliance year.	LSE must demonstrate procurement of 100% of their monthly obligation.

Under state and federal rules, the CPUC is empowered to set resource adequacy-related requirements for its jurisdictional LSEs, which include investor-owned utilities, community choice aggregators, and energy service providers. Collectively, these jurisdictional entities represent 90% of the load within the CAISO service territory. The CPUC requires all LSEs or Central Procurement Entities (CPE), if applicable, to maintain adequate generating capacity to meet their local, system, and flexible demands. To meet local requirements, LSEs or CPEs must procure resources sited in locations where supply is needed due to transmission constraints. For system requirements, LSEs must contract for sufficient resources to meet their share of the system's peak demand, plus reserves needed to meet the PRM. To meet flexible requirements, LSEs must procure resources that can ramp up or down on short notice to meet variations in demand and production (CPUC, 2023).

In California, System and Local Resource Adequacy requirements were established in 2004 and 2006, respectively; however, Flexible Resource Adequacy (Flexible RA) was introduced in 2015 to address growing system variability and ramping needs. The changing resource mix, both in-front-of (utility-scale wind and solar) and behind-the-meter (e.g., rooftop solar), have created a need for additional LSE requirements aimed at managing variability – particularly during the evening ramps. During the day, solar output from distributed resources (in aggregate) offsets what would otherwise be higher system loads. However, solar output rapidly declines as the sun sets, creating a steep increase in demand (ramp) that must be served by other resources on the CAISO system. During the same period, residential electricity demand also increases, as customers return home from work and use more appliances (especially air conditioning) during the late-afternoon and early-evening hours. This load pattern, often referred to as the duck curve (and more recently referred to as "net-load ramps") is exacerbated by the long, narrow, and north-south geographic orientation of the state.

Qualifying Capacity for Resource Adequacy Resources

The CPUC develops Qualifying Capacity (QC) values for all "Resource Adequacy Resources" (RA Resources) to determine the capacity of each resource eligible to be counted toward meeting the requirements. The CPUC-adopted QC counting conventions in **Table 14** depend on resource output limitations during periods of peak electricity demand and vary by resource type (CAISO, 2021):

Table 14: Qualifying Capacity as RA Resources

Resource Type	Examples and Attributes	Qualifying Capacity Counting Conventions Based On
Dispatchable	Natural gas; storage; geothermal	Maximum output of the generator when operating at full capacity—known as the Pmax
Dispatchable Hydro	Hydroelectric (optional)	Historical availability (option for up to Pmax)
Non-dispatchable geothermal and hydroelectric	Geothermal; hydroelectric	Historical production
Non-dispatchable Combined Heat & Power (CHP) and biomass	Biomass or CHP may bid into the day-ahead market, but are not fully dispatchable	Historical MW amount bid or self-scheduled into the CAISO's day-ahead market
Wind & Solar	Variable/intermittent in nature	ELCC[43]
Demand Response	Demand response programs	Historical performance

Resource Adequacy and Reliability

The fundamental benefit of California's RA Program is that RA Resources (and associated contracts) have a Must-Offer-Obligations (MOO) into one or more CAISO markets. The CAISO also has resource adequacy filing requirements that generally synchronize with CPUC-related requirements and that are outlined in the CAISO Tariff and Business Practice Manuals. These include the requirement that LSEs submit resource adequacy and supply plans to CAISO as part of the year-ahead and month-ahead resource adequacy-related processes.

The fundamental benefit of California's RA Program is that resources with RA contracts have a Must Offer Obligation (MOO) into one or more CAISO markets.[44] The CAISO also has RA filing requirements that generally synchronize with CPUC requirements and that are outlined in the CAISO Tariff and Business Practice Manuals. These include the requirement that LSEs submit RA and supply plans to CAISO as part of the year-ahead and month-ahead RA processes.

While CPUC's RA program is the primary planning process for ensuring there are sufficient resources available to the CAISO, the CAISO also maintains two backstop procurement processes:

43 ELCC approach has reduced the amount of qualifying capacity for these resources by approximately 80% (for example: a solar or wind resource that can produce 100 MW at the maximum output level would have a QC of 20 MW for meeting the CPUC's RA program). For additional information, see CPUC, D.19-06-026, Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the RA Program, June 27, 2019.

44 CAISO's energy market is comprised of multiple distinct day-ahead and real-time processes. CAISO also runs an ancillary services market with four product types: regulation up, regulation down, spinning reserve, and non-spinning reserve.

1. **Reliability Must Run (RMR) designations:** CAISO may designate a resource as RMR capacity to meet reliability needs.
2. **Capacity Procurement Mechanism (CPM) designations:** This is the "final step" of the RA process. If individual LSEs do not meet their capacity requirements or if all LSEs collectively do not meet a requirement, CAISO may designate CPM capacity through an auction process.

Resource Adequacy Reforms and Reliability Issues

The CPUC has continuously improved its RA program. The RA program has recently gone through significant enhancements. In addition to the longer-term enhancements (detailed further below) the Commission adopted several mechanisms to address the short-term reliability needs.

In January 2021 in response to two rotating outages in the CAISO footprint on August 14 and 15, 2020, CAISO, CPUC, and CEC released a Final Root Cause Analysis, which identified some of the contributing factors and provided recommendations (CPUC, CEC, and CAISO, 2021). The CPUC also opened an Emergency Reliability Rulemaking (R.20-11-003) to make more resources available on an expedited basis to prevent a recurrence of blackouts if the western United States experienced extremely high temperatures and sustained weather events in the summer of 2021 (CPUC, 2021). This rulemaking introduced efforts to ensure sufficient resources were available to meet California's summer electricity demand:

- **Updated Utility Procurement Requirements:** The CPUC ordered utilities to procure a minimum of an additional 2.5% of resources for all customers in their service territories, representing an effective increase of the PRM from 15% to 17.5%.
- **New Demand Response Programs:** To lower energy demand during the peak and net peak usage hours during a grid emergency, the CPUC ordered PG&E, SCE, and SDG&E to pilot an Emergency Load Reduction Program (ELRP) that would give demand response providers and other companies providing new services to manage electricity demand, the ability to demonstrate how their innovative programs can support the grid. The pilot program compensates customers for voluntarily reducing demand on the power system when called upon to do so by the CAISO in the event of a grid emergency. This program serves as a layer of insurance on top of existing resource adequacy plans and gives grid operators a new tool among the existing demand management programs to address unexpected power system conditions.
- **Improvements to Existing Demand Response Programs:** The CPUC ordered modifications to existing demand response programs to expand participation, including temporarily allowing year-round enrollment in utility "interruptible programs" that allow for industrial and large commercial customers to pay a lower rate in exchange for allowing the utility to curtail their energy usage when energy demand is high and/or the reliability of the electric grid is threatened. The CPUC also increased demand response program enrollment incentives to attract new customers and allowed SDG&E to expand and enhance its AC Saver program by allowing residential net energy metering customers to enroll, as well as incentivizing smart thermostat manufacturers to increase the number of participating thermostats.
- **Improved Rate Plans to Encourage Conservation:** The CPUC ordered utilities to modify their Critical Peak Pricing programs, which charge a higher price for electricity consumption during peak hours on selected days. The CPUC ordered several modifications to the Critical Peak Pricing programs to ensure the program is more effective and responsive to the critical three hours of a grid emergency, including shifting the Critical Peak Pricing event window for residential and non-residential customers to the hours of 4 p.m. to 9 p.m., increasing the maximum number of Critical Peak Pricing events allowed per year, and providing customer education with a focus on increasing participation. The CPUC reinstated the Flex Alert

paid media program to educate consumers about the positive impacts of conservation, help customers understand grid conditions, and inform customers of the need to conserve when energy demand is high.

More recently in Decisions 21-07-014, 22-06-050, and 23-04-010 the CPUC adopted the Slice-of-Day (SOD) framework. The new framework is designed to address the changing electric system by setting hourly RArequirements based on the peak day of the month rather than the current focus on only the peak hour. Itaddresses the increased penetration of energy storage and other use-limited resources by ensuring sufficientcapacity to meet load in every hour and charge storage requirements.2024 will be a test year for the SODframework with full implementation expected in 2025.

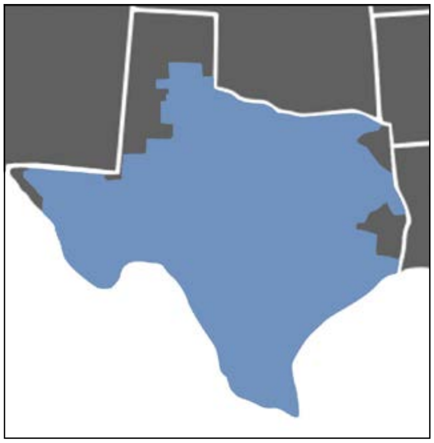
In June 2023, the Commissions adopted additional reliability improvements in the Implementation Track of the RA Proceeding, Decision (D.) 23-06-029:

- **Increases the Planning Reserve Margin (PRM) for 2024-2025:** The CPUC implemented a 17% PRM requirement for 2024-2025, increased from the 16% PRM that was instituted in 2022, predicated by a 15% PRM that had been in place since 2005. The decision also extends the "effective PRM procurement target" of 22.5% (requiring IOUs to carry an additional combination of reserves including some that do not qualify as RA resources described above.
- **Modifies or Clarifies Resource Adequacy Program Rules:** The CPUC introduced more detailed guidelines for Community Choice Aggregator (CCA) and other LSEs related to their RA requirements. Additional rules were also established for how LSEs can use qualifying imports and DR programs in meeting system RA requirements. The Commission also provided more specific rules for counting the value of DR resources.
- **Directs Energy Division to Continue to Refine Future Resource Adequacy Programs:** The final provision of the Decision addressed additional efforts that the Commission and stakeholders will take in the coming years related to load forecast frequency, the counting of DR resources, RMR credits and timelines, and publishing resource adequacy deficiencies.

Additional Information on Resource Adequacy in California ISO

- California Public Utilities Commission: Resource Adequacy Program – CPUC (Link)
- California Public Utilities Commission: Procedural History of the 2021-Present Resource Adequacy Proceedings, including R.21-10-002 – CPUC (Link)
- 2021 Resource Adequacy Report – CPUC (Link)
- California ISO: Resource Adequacy Fact Sheet – CAISO (Link)
- California ISO: Reliability Requirements – CAISO (Link)
- California ISO: Seasonal Assessments – CAISO (Link)
- California ISO: Renewables Integration Reports and Studies – CAISO (Link)
- California ISO: Market Operations – CAISO (Link)
- California ISO Tariff – CAISO (Link)
- California ISO Business Practice Manuals – CAISO (Link)

Electric Reliability Council of Texas



Area Summary: The Electric Reliability Council of Texas (ERCOT) is a single-state independent system operator (ISO) with asynchronous ties to the larger Eastern and Western Interconnections, with limited DC ties to the East and Mexico. As a membership-based 501(c)(4) nonprofit corporation, ERCOT also manages power flows for more than 52,700 miles of transmission lines and over 1,100 generation units. ERCOT runs a competitive wholesale bulk-power market, performs financial settlements, and administers retail switching for eight million premises in competitive choice areas.

State(s): Texas (ERCOT manages the flow of electric power to approximately 75% of the land area and 90% of the state's electric load.)

Regional Reliability Authorities: Texas Reliability Entity, Inc. (Texas RE)

State Commission(s): Public Utility Commission of Texas (PUCT)

Forums for Regulatory Involvement: Public Utility Commission of Texas (PUCT) maintains jurisdiction over the activities conducted by ERCOT. The Chair of the PUCT is an ex-officio (non-voting) member of ERCOT's Board of Directors with additional oversight by the Texas legislature. The Regional Planning Group (RPG) reports directly to the ERCOT Board of Directors as a stakeholder group focused on issues related to planning the ERCOT system for reliable and efficient operation. Stakeholders include all market participants, transmission and distribution service providers, and PUCT staff.

Entities Involved in Resource Adequacy and Planning

ERCOT is governed by an independent board of directors and subject to oversight by the Public Utility Commission of Texas (PUCT) and the Texas legislature. Its membership includes consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned utilities (IOUs), transmission and distribution providers, and municipally-owned electric utilities. The grid operator has four primary responsibilities (ERCOT, 2023):

1. Maintaining system reliability;
2. Facilitating a competitive wholesale market;
3. Facilitating a competitive retail market; and
4. Ensuring open access to transmission.

The PUCT maintains jurisdiction over activities conducted by ERCOT and performs regulatory functions for electric transmission and distribution utilities across the state. Vertically integrated electric utilities (i.e., utilities that own generation, transmission, and distribution) within Texas, but outside of the ERCOT system, are also regulated by the PUCT. FERC regulatory authority in Texas is limited to bulk electric system reliability, chiefly through application of NERC Reliability Standards, and does not apply to power markets. The PUCT is involved in multi-state efforts to monitor wholesale electric competitive market structures and transmission planning in the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) areas, which are connected to the Eastern Interconnection. The far west portion of Texas is connected to the Western Interconnection and served primarily by El Paso Electric (EPE) but is also under PUCT jurisdiction. In 2023, EPE joined the Western Energy Imbalance Market (WEIM), operated by California Independent System Operator (CAISO).

The Texas Legislature deregulated the retail electric market in 1999 to promote retail competition that allows consumers to choose their energy supplier. When this occurred, generators, transmission and distribution companies, and electric retailers began to operate independently from one another, apart from municipally-owned utilities and cooperatives that remain vertically integrated. Currently, 75% of ERCOT's load is competitive-choice customers (ERCOT, 2023). ERCOT is unique in that it is an energy-only market. ERCOT only runs energy and ancillary services markets and does not administer a capacity market.

ERCOT assesses resource adequacy with internal staff members, developing system-wide reliability studies, load forecasts, and other analyses. These experts work with stakeholders through a variety of committees, working groups, and task forces. The Technical Advisory Committee (TAC) is comprised of ERCOT stakeholders and is responsible for making recommendations to the Board of Directors, supported by four subcommittees, two of which work on resource adequacy-related issues.

The Reliability Operations Subcommittee (ROS) is responsible for developing, reviewing, and maintaining planning and operating criteria for the ERCOT system. Additionally, the ROS and Wholesale Market Subcommittee jointly review ERCOT protocol revisions and perform protocol-required reviews of ancillary service provisions and commercially significant constraints. The Planning Working Group (PLWG) reports to the ROS and reviews planning guidelines to identify any needed improvements to criteria, processes, and data provision requirements for grid studies. The PLWG is a non-voting group within ROS which reviews the Planning Guides to identify any required improvements to planning criteria, processes, and data provision requirements as well as to maintain alignment with requirements within NERC Reliability Standards.

The Wholesale Market Subcommittee (WMS) is the second subcommittee that reports to ERCOT's Technical Advisory Committee (TAC), responsible for reviewing issues related to the operation of the wholesale market in the ERCOT region and developing recommendations for improvement. The WMS monitors PUCT rulings as they apply to wholesale markets and market participants. Among its many functions, the WMS provides input into the methodology for determining competitive constraints, changes to ancillary services (AS) and the evaluation of resource adequacy in the ERCOT region. The WMS also monitors the AS market operations and management of system congestion. The Supply Adequacy Working Group (SAWG) reports to the WMS with members addressing all resource adequacy-related issues in ERCOT. Some key responsibilities of the SAWG include maintaining and updating the Capacity, Demand, and Reserves (CDR) and Seasonal Assessment of Resource Adequacy (SARA) reports, which are used in the modeling of various studies conducted by ERCOT and consultants. The SAWG is also involved in efforts to enhance metrics through proposed revision requests to change the methodology of capacity accreditation as well as temperature-based thermal outage modeling.

In addition to the TAC referenced above, the Regional Planning Group (RPG) reports directly to the ERCOT Board of Directors. The RPG is a stakeholder forum for input on issues related to planning the ERCOT system for reliable and efficient operation. ERCOT staff leads the RPG, and membership is open to all market participants, transmission and distribution service providers, and other stakeholders. This group is also open to participation from PUCT staff. Members provide input into annual and special planning studies, review proposed transmission projects, and provide comments to inform ERCOT's independent review of projects. The RPG manages a process for developing and reviewing the Long-Term System Assessment (LTSA), which evaluates the potential needs of the ERCOT high-voltage (345 kilovolt) system 10-15 years into the future and provides a scenario-based view of long-term needs across a range of possible future generation expansion scenarios. Information from the LTSA is fed into the ERCOT 1-10-year planning process to inform transmission project decisions that meet the ERCOT reliability and economic criteria.

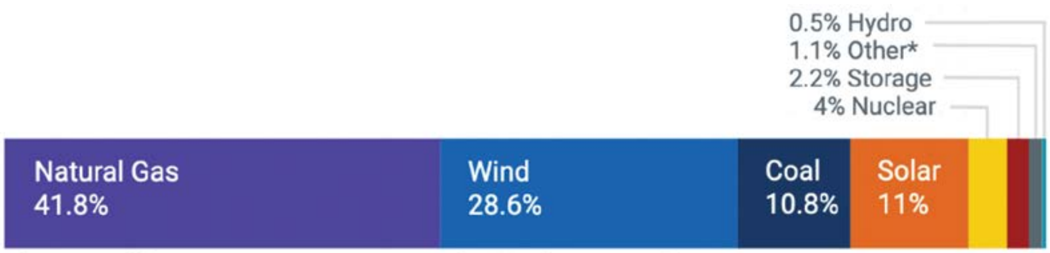
Resource Adequacy and System Planning Processes

There is currently no mandated planning reserve margin for ERCOT.[45] A target reserve margin (i.e., reference margin level) of 13.75% for the peak load window is used in NERC assessments. ERCOT still conducts extensive studies of reserve outlook and the PUCT did consider incorporating approaches for an economic or market-based equilibrium reserve margin, as identified in recent studies (Carden and Dombrowsky, 2021).

Although ERCOT does not mandate a resource adequacy requirement for load serving entities, the Operating Reserve Demand Curve (ORDC) serves as a market mechanism that "values operating reserves in the wholesale electric market based on the scarcity of those reserves and reflects that value in energy prices."(ERCOT, 2022). The ORDC serves as a price adder in the energy-only market designed to estimate and reflect a premium paid to generators with available capacity during periods when operating reserves are limited. ERCOT must provide a biennial report "analyzing the efficacy, utilization, related costs, and contribution of the ORDC to grid reliability" to the PUCT in accordance with Substantive Rule §25.505, subsection (e) (ERCOT, 2022). The parameters of the ORDC have been modified in response to system events, including Winter Storm Uri, resulting in higher price signals that more effectively incent offers of additional capacity during times of lower frequency responsive reserves when there is greater risk to grid reliability.

More than 37 GW of installed wind capacity (mostly located in west Texas) has been added to ERCOT's system as of January 2023. Wind generation now accounts for over a quarter of the state's nameplate generating capacity. Solar is growing rapidly as well, with more than 14 GW synchronized and at more than 20 GW additional in various stages of the interconnection process with potential grid availability within the next two years. Texas also relies heavily on natural gas-fired resources, which are useful in countering the variability of wind and solar (**Figure 16**).

Figure 16: ERCOT's 2023 Generating Capacity[46] (ERCOT, 2023)



The sum of the percentages may not equal 100% due to rounding.
**Other includes biomass and DC Tie capacity.*

Because of the high variability in wind production, ERCOT uses a top 20 peak load hours, 10-year historical averaging approach for projecting the amount of wind availability during a given season. **Table 15** shows how the summer peak average wind capacity percentages have been updated annually since 2011 for each of the three ERCOT geographic forecasting zones (ERCOT, 2023). When examining the capacity contribution in 2022, a 72.6% of the nameplate wind capacity for the coastal region is counted as available, whereas the 10-year weighted average results in a 60% capacity contribution assumed for existing and future wind resources in ERCOT's planning studies. The same approach is also used for winter seasonal peak capacity contributions.[47]

45 Project 54584 has been opened recently to evaluate and establish the appropriate reliability standard for the ERCOT region.

46 Reflects operational installed capacity based on the November 2022 CDR report for Summer 2023.

47 ERCOT is in the process of replacing the current Peak Average Capacity Contribution method with an ELCC method.

Table 15: Summer Peak Average Wind Capacity Percentages and Total Unit Capacities

Year	Coastal		Panhandle		Other	
	Capacity Contribution	Capacity (MW)	Capacity Contribution	Capacity (MW)	Capacity Contribution	Capacity (MW)
2022	72.6%	4,858	24.2%	4,406	19.0%	18,531
2021	40.6%	3,579	37.5%	4,406	24.9%	15,411
2020	43.5%	3,283	25.7%	4,406	26.8%	14,737
2019	75.2%	2,814	34.1%	4,196	23.5%	12,178
2018	53.1%	2,613	25.6%	4,196	18.2%	11,487
2017	63.5%	2,136	24.5%	4,022	21.8%	10,035
2016	73.6%	1,839	48.4%	2,870	19.4%	8,562
2015	53.3%	1,674	17.3%	1,776	10.3%	7,116
2014	60.2%	1,673	21.2%	207	18.6%	6,318
2013	76.4%	1,274	10.9%	207	12.6%	6,099

A similar approach used for solar generation yields a significantly higher weighted average summer peak contribution of 79% (but negligible winter contributions). ERCOT also treats capacity contributions of Private Utility Networks (grid exports mainly from cogeneration) and hydro based on historical averages. For net imports across the DC ties, ERCOT uses the amount that was available during the most recent energy emergency alert for the summer and winter seasons.

Resource Adequacy Assessments

ERCOT currently releases its Capacity, Demand and Reserves (CDR) report in May of each year, followed by an update in December. ERCOT releases its Seasonal Assessments of Resource Adequacy (SARA) reports for the spring, summer, fall, and winter. These resource adequacy reports use a deterministic approach to calculate if ERCOT is expected to have adequate forecasted reserves above the forecasted peak demand.

The SARA reports also examine impacts of the most important variables that affect the availability of resources to meet ERCOT's seasonal peak demands. By examining a range of resource adequacy outcomes, the SARA serves as a planning tool for electric utilities and other entities within the ERCOT region. The report includes season-specific scenarios that examine a combination of high peak loads, low wind and solar output, and high thermal generator outages. The most extreme scenarios account for potential conditions caused by extreme weather events. The scenarios are based on historic ranges of the parameter values or known changes expected in the near-term. These scenarios support the "extreme weather" resource adequacy assessment requirement established by the PUCT in Rule 25.362(i)(2)(H) (PUCT, 2014). ERCOT has also developed a drought risk monitoring tool to screen for potential drought-related impacts to generation resources (ERCOT, 2023).

Resource Adequacy Reforms and Reliability Issues

ERCOT identifies reliability risks on an annual basis within their long-term assessments. The most recent report indicated that the following issues may impact reliability on the ERCOT system (ERCOT, 2022):

- Significant growth of inverter-based resources (IBR).
- More advanced natural gas generation with higher efficiencies.
- Fewer new capacity additions due to a lower demand forecast.
- Growth in renewable resources and electric vehicle adoption, contributing to a shift in scarcity hours later in the day.
- Gradual shift in scarcity hours from primarily in the summer season to the winter season (most of the scarcity hours in 2027 projected to occur during the summer, while more than half of the scarcity hours in 2032 projected to occur during the winter. In 2037, almost all scarcity hours are projected to occur during the winter. Some factors that impact the shift in scarcity hours include growth in electric vehicle (EV) adoption, high net load ramping from the late evening drop-off in solar production, and low solar production in the evening coupled with limited wind output, resulting in the need for additional dispatchable resource types to meet peak net demand.
- Annual capacity factors for conventional generators were significantly higher in the Demand Side Evolution scenario compared with the Current Trends and Expanded System Outlook scenarios.

ERCOT has identified the following transmission challenges:

- Flows from the region with renewables (Texas panhandle) and flows into various demand centers.
- ERCOT has identified significant congestion on the West Texas Export interface and import paths to demand centers such as Dallas-Fort Worth and Houston driven by a changing resource mix and trends in the demand growth. The Dallas-Fort Worth area congestion is driven by generation additions in northwest and load growth.
- Import paths to Houston were shown to be highly congested due to conventional generation retirements, renewable additions in South, North and West Texas and load growth.
- The addition of renewable resources in North and West Texas indicated projected congestion rents of nearly $1 billion to export energy from West Texas in the model year 2037.

Regarding resource adequacy reforms, ERCOT has conducted probabilistic analysis to look at periods other than peak hour, as the characteristics of renewable generation may shift risks. Capacity contributions from distributed energy resources and battery energy storage are not yet significant, but the number of these resources is expected to grow in the coming years. Work has begun to collect data and establish performance characteristics so that ERCOT can incorporate these resources into planning and establish the necessary market rules. ERCOT is also in the process of using Effective Load Carrying Capability as a replacement for the current Peak Average Capacity Contribution method for wind and solar resources.

The PUCT also recently opened a rulemaking project to develop a reliability standard for the ERCOT region as directed by 87th Texas Legislature's Senate Bill 3. The project will consider multiple metrics beyond the industry standard 1-in-10-day LOLE to establish an appropriate reliability standard that ensures resource adequacy. The project will be supplemented by additional studies that aim to update the Value of Lost Load (VOLL) and Cost of New Entry (CONE).

Additional Information on Resource Adequacy in ERCOT

- About the Public Utility Commission of Texas – Mission and History (Link)
- ERCOT Committees and Groups (Link)
- 2022 Biennial ERCOT Report on the Operating Reserve Demand Curve (Link)
- Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024 (Link)
- ERCOT – Reliability and Operations Subcommittee (Link)
- Effective Load Carrying Capability Study (Link)
- PUCT Ongoing Reliability Reforms (Link)
- PUCT Biennial Agency Report (Link)
- Project No 54584 Reliability Standard for the ERCOT market (Link)
- *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024* – Astrapé Consulting (Link)

ISO-New England

Area Summary: ISO New England Inc. (ISO-NE) is an independent, non-profit RTO created in 1997 by FERC, as a replacement for the New England Power Pool, which was established in 1971. ISO-NE oversees the operation of New England's bulk electric power system and transmission lines, including electricity generated and transmitted by its member utilities, as well as by Hydro-Quebec, NB Power, the New York Power Authority, and utilities in New York State (when the need arises).[48] ISO-NE is responsible for reliably operating a 32,000 MW bulk electric power generation and transmission system. The ISO-NE power grid footprint consists of 9,000 miles of high-voltage transmission lines (115 kV and above) and 13 transmission interconnections to power systems in New York and Eastern Canada.

State(s): Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

Regional Reliability Authorities: Northeast Power Coordinating Council (NPCC)

State Commission(s): Maine Public Utilities Commission; New Hampshire Public Utilities Commission; Vermont Public Utility Commission; Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission; and the Connecticut Public Utilities Regulatory Authority

Forums for Regulatory Involvement: New England States Committee on Electricity, Inc. (NESCOE), New England Power Pool (NEPOOL), and the New England Conference of Public Utilities Commissioners (NECPUC)

Entities Involved in Resource Adequacy and Planning

The products traded in New England's wholesale electricity markets comprise three major categories: 1. energy markets (for buying and selling day-to-day); 2. capacity market (to address long-term system reliability); and 3. ancillary services (to address short-term system reliability). ISO NE's stated mission is to protect the health

48 The ISO-NE grid does not extend to remote parts of eastern and northern Maine in Washington and Aroostook Counties. In these areas, residents receive their electricity from Canadian providers such as NB Power and Hydro-Quebec. In addition, parts of the Vermont distribution system can operate by receiving electric service from either the Vermont/ISO-NE system or Hydro-Quebec system.

of New England's economy and the well-being of its people by ensuring the constant availability of electricity, both today and for future generations. One of its major duties is to provide tariffs for the prices, terms, and conditions of the energy supply in New England. ISO-NE also ensures the day-to-day reliable operation of New England's bulk electric generation and transmission system, oversees the administration of the region's wholesale electricity markets, and manages comprehensive, regional planning processes.

Resource Adequacy and System Planning Processes

One of ISO-NE's responsibilities as an RTO is to maintain resource adequacy for the New England control area (i.e., ensure that the region will have adequate transmission, generation, and demand resources to serve the future electricity needs of New England's households, businesses, and industries. To satisfy its resource adequacy responsibility, ISO-NE sets an annual system capacity requirement by calculating the Installed Capacity Requirement (ICR). The ICR is that quantity of capacity the ISO projects the region needs to meet both ISO-NE's and the Northeast Power Coordination Council's reliability standards for satisfying the region's peak demand forecast while maintaining required operating reserves. The ICR calculation accounts for uncertainties, contingencies, and resource performance under a wide range of existing and future system conditions. The ICR calculation and the process to arrive at it is complicated and requires numerous inputs. Among these inputs are energy forecasts, which are based on economic activity and outlook; weather and load patterns; residential, industrial, and commercial demand; existing resource retirements and new resource entry; distributed generation, especially photovoltaics; and pending or proposed legislation, regulation, and standards. The ICR calculation also takes into consideration expected demand reductions as informed by an energy-efficiency forecast and expected demand increases associated with electrification of transportation and building heating. States and other market participants engage actively in the process to develop and vet these ICR calculation inputs.

ISO-NE operates the Forward Capacity Market (FCM) as the vehicle to achieve and maintain resource adequacy. The FCM consists of annual Forward Capacity Auctions (FCAs) in which generators, demand resources, and importers submit offers to provide capacity three years in advance of an annual capacity commitment period. The FCAs use ICR-derived marginal reliability impact (MRI) demand curves to determine the least cost quantity of procured capacity to satisfy reliability requirements for the region as a whole and for subregional capacity zones. In this way, the FCM provides compensation sufficient to retain existing, and attract new, resources on a long-term, least-cost basis.

ISO-NE qualifies resources as eligible to enter the FCM and sell capacity. In addition to merchant resources, New England states historically have provided financial support to specific resources to generate energy in line with state policy goals (e.g., long-term power purchase agreements and renewable portfolio standards designed to incentivize the development of new clean energy resources). In addition to selling energy, these state-sponsored resources are eligible to qualify and participate in the FCM and thus may serve to support regional resource adequacy.

Some of the New England states also conduct integrated resource planning separately from the ISO-NE process. Vermont requires its distribution utilities to develop integrated resource plans on a three-year basis (Vermont DPS, 2022). These integrated resource plans are informed by Vermont's participation in the bulk transmission system and the regional electricity markets. Connecticut's Department of Energy and Environmental Protection regularly produces an IRP, which looks at wholesale market activities and trends as well as state-level activities and policies. In New Hampshire, public utilities will no longer be required to provide IRPs as of October 2023, due to a legislative repeal of that obligation. The Maine Public Utilities Commission is currently engaged in Docket 2022-00322, a proceeding to identify priorities for grid planning.

Resource Adequacy Reforms and Reliability Issues

ISO-NE's ability to meet resource adequacy efficiently is becoming challenging on several fronts, as the region faces rising electricity demand, increasing penetration of non-firm generation resources, seasonal constraints in natural gas deliverability, and resource retirements. These challenges are driven by policy and market conditions – including natural gas price volatility, constrained winter natural gas supply, economic pressure on dispatchable generation by low cost (or low variable cost) non-dispatchable generation, and state clean energy and carbon reduction policy objectives.

Recent resource adequacy activity in New England has focused on efforts to align the FCM design with state policy objectives. Over the past several years this activity has led to the development of several market reforms. Current efforts are addressing proposed reforms of capacity retirement and accreditation rules, while future efforts may consider the benefits of transitioning to seasonal and prompt capacity market designs.

Additional Information on Resource Adequacy in ISO-New England

- About the FCM and Its Auctions – ISO-New England (Link)
- Resource Capacity Accreditation in the Forward Capacity Market (Key Project) – ISO-New England (Link)
- Maine Public Utilities Commission – Case Number: 2022-00322. Maine Public Utilities Commission Proceeding to Identify Priorities for Grid Plan Filings (Link)
- New England Conference of Public Utility Commissioners (Link)
- New England States Committee on Electricity (Link)
- ISO-NE Planning Advisory Committee (Link)

Midcontinent ISO

Area Summary: The Midcontinent ISO (MISO) is an independent, not-for-profit, member-based organization responsible for keeping the power flowing across its region reliably and cost effectively. MISO focuses on three critical tasks: 1.) Managing the flow of high-voltage electricity across 15 U.S. states and the Canadian province of Manitoba; 2.) facilitating one of the world's largest energy markets with more than $40 billion in annual transactions; 3.) planning the grid of the future. M ISO's territory includes over 68,000 miles of transmission lines andover 6,800 generating units. MISO participants include 57 transmission owners 135 non-TOs, and over 500 market participants

State(s): Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi,, Missouri, Montana, North Dakota, South Dakota,Texas, and Wisconsin

Regional Reliability Authorities: Midwest Reliability Organization (MRO), Reliability First (RF), and SERC

State Commissions(s): Arkansas Public Service Commission, Illinois Commerce Commission, Indiana Utility Regulatory Commission, Iowa Utilities Board, Kentucky Public Service Commission, Louisiana Public Service Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission, Mississippi Public Service Commission, Missouri Public Service Commission, Montana Public Service Commission, North Dakota Public Service Commission, South Dakota Public Utilities Commission, Public Utility Commission of Texas, and the Public Service Commission of Wisconsin

Forums for Regulatory Involvement: Organization of MISO States (OMS)

Entities Involved in Resource Adequacy and Planning

Under MISO's resource adequacy construct, electric utilities, referred to as load-serving entities (LSEs), are responsible for demonstrating or procuring sufficient resources with oversight by states and their relevant electric retail regulators. MISO's resource adequacy construct recognizes and supports the independent authority of state utility regulators for resource adequacy. States have the authority to determine how resource adequacy needs are met by LSEs within their state and maintain decision-making authority over the amount and types of resources that are necessary to accomplish these objectives. MISO's role is to provide transparency and to support and facilitate shared resource adequacy goals through its processes.

MISO recognizes that state utility regulators play a key role in ensuring that regulated utilities meet resource adequacy requirements. Module E-1 of MISO's tariff states "[n]othing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the state's jurisdiction."(MISO, 2018).

State utility regulators in the MISO region participate in the MISO Resource Adequacy Subcommittee (RASC) individually, and often jointly, through the Organization of MISO States (OMS), which includes utility regulators from all states that regulate load serving entities in MISO (as well as the City Council of New Orleans and the Manitoba Public Utilities Board). MISO's RASC hears presentations from MISO on pending resource adequacy changes, receives input from participating stakeholders, and provides guidance on regional resource adequacy issues, tariffs, and business processes to MISO management. OMS's Resource Adequacy Work Group, made up of staff from its member states, regularly provides formal feedback on RASC presentations, concepts, and proposals throughout the year. At the OMS Board level, Resource Adequacy is a 2023 OMS Strategic Priority, such that an OMS Board liaison is tasked with tracking the issue throughout the year, providing directional guidance for the Resource Adequacy Work Group, and flagging items for OMS Board attention (OMS, 2023).

Based on the State's jurisdictional role with respect to resource adequacy, MISO consults directly with OMS and sometimes individual states on resource adequacy topics and proposed changes. In the last several years educational sessions and consultations with the states have included changes related to the availability of demand response resources required to receive capacity credit, changes to MISO's methodology to calculate capacity import and export limits, briefings related to capacity auction results, presentations at state commission meetings, and new proposals such as a sloped demand curve prior to MISO's formal filing at the FERC.

In addition, MISO partners with OMS to conduct a survey to provide a view into the region's supply and demand balance in future years. Utility regulators also encourage jurisdictional utilities to provide projected information that may be sensitive related to planned retirements that have not yet been publicly announced. The aggregate results of each annual OMS-MISO survey are shared with state utility regulators and the public, providing a 5-year point-in-time forecasted range of supply/demand balance outcomes that may occur based on potential actions taken by MISO states, LSEs, and independent resource owners to retire, suspend, or build generation resources. OMS independently conducts distributed energy resource (DER) surveys annually to provide information from jurisdictional utilities to MISO related to the amounts, types, and locations of DERs broken down by whether or not the resource is registered at MISO. DERs not registered as a MISO resource have an ability to impact load levels and influence resource adequacy. The OMS-MISO surveys help utility regulators in various states, as well as the RTO to have a clearer picture of the current and projected resource adequacy status within the region.

Resource Adequacy and System Planning Processes

Electric distribution companies provide MISO with load forecasts that include any retail choice load in their service territory.[49] The load forecasts provided by the LSEs to MISO include the impact of any decrease related to energy efficiency or DERs, including any increases related to electrification or other near-term expected load growth. The Illinois Power Agency conducts solicitations for capacity for the upcoming planning year to ensure sufficient resources are offered to serve load (OMS, 2022). The Michigan Public Service Commission conducts four-year forward capacity demonstrations to ensure sufficient resources are available to meet future load (MSPC, 2023). Elsewhere in MISO, states typically plan for longer-term resource adequacy through integrated resource plans, or case-by-case resource investment decisions. Near-term resource adequacy is demonstrated in MISO's planning resource auction (PRA), where LSEs demonstrate compliance with MISO's reliability requirements.

MISO, along with input from its stakeholders, establishes requirements to meet a reserve margin above peak load expectations for four seasons each year. MISO's resource adequacy construct transitioned from an annual to a seasonal framework, beginning in the 2023 planning year.[50] MISO's tariff provides deference to states that establish a different planning reserve margin (PRM) for its jurisdictional utilities and will implement the PRM established by the state for those utilities (MISO, 2018). This tariff provision has never been utilized.

In MISO, LSEs must demonstrate sufficient resources in each season for the coming planning year by one of several methods, including a Fixed Resource Adequacy Plan (FRAP), Self-Schedule, or by purchasing from the MISO PRA (MISO, 2018). When sufficient levels of resources are demonstrated by LSEs or purchased in the auction, the resource adequacy requirements established by MISO are met. Reserve margin requirements consider both: 1.) a regional requirement (i.e., the total amount of capacity needed to meet the reliability standard, associated with a system-wide coincident peak demand; and 2.) a local requirement (i.e., the amountof the total capacity that must be located within each local resource zone). MISO works with market participantsto establish a PRM that defines the quantity of resources required by each LSE above its seasonal peak load to reliably meet demand when considering risk factors such as generator forced outages and weather uncertainty.MISO's planning reserve margin is a percentage of the seasonal forecast coincident peak load and is basedon a loss-of-load expectation (or LOLE) of 1-day-in-10-years. This percentage is then used to determine howmuch capacity (in megawatts) each LSE needs to meet its regional needs. This is how each LSE's planningreserve margin requirement (or PRMR) is established.

The locational component of MISO's resource adequacy construct is addressed through the identification of local resource zones, which are then used to define local resource requirements throughout the footprint. For each of these zones, a local clearing requirement for each season is defined and accounts for limits on the transmission system's ability to reliably import capacity from other zones. This approach promotes the maintenance of sufficient and available resources within each zone to meet demand at non-coincident peak conditions.

MISO determines the capacity value of resources using different methods. Under the current seasonal construct, resources in the thermal class are accredited using unforced capacity based on a rolling five-year equivalent demand forced outage rate that excludes causes outside of management control, planned outages, and de-rates. Each thermal unit's seasonal accreditation is determined by Schedule 53, which effectively allocates the total system-wide unforced capacity value to individual resources based on their actual performance during tight margin hours (MISO, 2023). Wind resources are accredited using seasonal system-wide ELCC analysis and allocating a value to individual wind resources based on their performance during each season's top eight peak load hours. Solar resources are accredited based on three years of historical average output

49 Illinois and Michigan are the only states in the MISO region that have retail choice programs, as of October 2023.

50 Prior to planning year 2023, MISO had an annual resource adequacy construct as opposed to seasonal.

(with curtailments added to the actual real-time output) of the resource for hours ending 15:00,16:00, and 17:00 (ET) for the most recent spring, summer, and fall months and hours ending 8:00, 9:00, 19:00, and 20:00 (ET) for the most recent winter months. New solar resources receive the class average for the initial planning year which is 50% for spring, summer, and fall, and 5% for winter. Demand resources are accredited based on adding transmission losses and the load's share of the planning reserve margin requirement to their verified curtailment capacity with a recent enhancement in 2020 to better align demand resource accreditation with availability by reflecting number of calls and lead-time attributes. All resources must demonstrate their effective deliverability in order to achieve their full accredited value.

MISO's annual planning resource auction, including the auction for each individual season, is conducted each April for the entire planning year that starts the subsequent June 1. The auction selects the least-cost set of planning resources necessary to meet both regional and local requirements for each local resource zone, considering transmission limits, to provide price signals that reflect the location of resources. LSEs must demonstrate resource adequacy requirements are met through submission of a fixed resource adequacy plan (matching of owned generation and load obligations), demonstration of contractual rights to certain resources through a self-schedule, purchase of capacity in the auction, or a combination thereof. LSEs can also pay a capacity deficiency charge to "buy out" of their obligations. Owing to the largely vertically integrated nature of MISO and state resource adequacy processes, a significant portion of the total regional requirements are met through fixed resource adequacy plans and self-schedules (e.g., 86% or greater for each season in the 2023/24 Planning Year). Hence, MISO's auction is often described as a "residual auction."

Resource Adequacy Reforms and Reliability Issues

Each year, there are significant changes to the resource portfolio that MISO and its members rely on to maintain reliable operations. MISO has experienced heightened risk of capacity insufficiency in all seasons. General trends recently have included additional retirements of dispatchable fossil fuel resources in MISO and growing reliance on renewable generation, energy market imports, and emergency-only demand response. It is becoming increasingly difficult and complex for any given LSE or state to gauge the reliability impacts of their plans on the region and for MISO to ensure regional capabilities are sufficient.

Since 2017, MISO has been working to better align capacity and planning requirements with operations. Early efforts focused on improving situational awareness by improving transparency and refining resource availability requirements. Now MISO is working with stakeholders on a reliability-based demand curve (RBDC), which is a downward sloping demand curve, aimed at properly valuing incremental capacity, recognizing that additional capacity above the 1-day-in-10-years LOLE standard provides additional reliability. MISO's RBDC proposal aims at providing capacity prices to better support market participant's retirement and replacement decisions and resulting in more economically efficient outcomes reflecting the appropriate price of capacity. MISO is currently working with stakeholders and has consulted with OMS on the design of potential opt-out provisions. MISO intends to finalize the design of the RBDC and opt-out provisions by filing with FERC in 2023 with implementation scheduled for planning year 2025.

MISO is also working extensively to reform its capacity accreditation methods to align with the periods of both the highest potential and realized system risks amidst the ongoing transition to higher amounts of intermittent generation and shifting periods of risk. MISO's proposal is a marginal accreditation approach and includes a two-step process, accounting for the ELCC of an additional new unit of each resource type and allocating credit to individual units based on their past performance during identified risk periods (i.e., tight margin hours). The stakeholder discussions surrounding MISO's resource accreditation proposal are ongoing and MISO expects to file a proposal with FERC in late 2023.

Additional Information on Resource Adequacy in the Midcontinent ISO

- MISO Resource Adequacy and Related Documents – MISO (Link)
- Resource Adequacy Subcommittee – MISO (Link)
- Regional Resource Assessments – MISO (Link)
- Resource Adequacy/Seasonal Accredited Capacity FAQ – MISO (Link)
- Loss of Load Expectation Working Group – MISO (Link)
- MISO Tariff: Schedule 53 – Seasonal Accredited Capacity Calculation – MISO (Link)
- OMS 2023 Strategic Priorities – Organization of MISO States (Link)

New York ISO

Area Summary: The New York Independent System Operator (NYISO), which began operating in 1999, is a not-for-profit corporation primarily regulated by FERC. The NYISO is governed jointly by market participants and an independent board of directors. The organization's primary responsibility is to operate the bulk electric system, administer wholesale electricity markets, and conduct system planning for the state of New York. The creation of the NYISO resulted in reliability and economic benefits, as well as improved system efficiency, with a shift toward cleaner sources of generation. The mission of the NYISO is to "ensure power system reliability and competitive markets for New York in a clean energy future," while a new NYISO Vision Statement provides for "Working together with stakeholders to build the cleanest, most reliable electric system in the nation." The NYISO, in collaboration with its stakeholders, serves the public interest and provides benefit to consumers by: maintaining and enhancing regional reliability; operating open, fair, and competitive wholesale electricity markets; planning the power system for the future; providing factual information to policymakers, stakeholders, and investors in the power system (NYISO, 2022). The NYISO is responsible for managing the electricity flow across more than 11,000 miles of high-voltage transmission lines. This also involves balancing the supply of resources with the demand needs throughout the state. The NYISO markets must be designed and operated in accordance with the federal policy of open and non-discriminatory access to the grid.

State(s): New York

Regional Reliability Authorities: Northeast Power Coordinating Council, New York State Reliability Council (NYSRC)

State Commission(s): New York State Public Service Commission (NYPSC)

Forums for Regulatory Involvement: The New York State Reliability Council (NYSRC) is governed by the Executive Committee, comprised of 13 members from various sectors, and is responsible for maintaining the state's reliability rules, including the establishment of the system's installed capacity requirement and associated reserve margin for the New York control area.

Entities Involved in Resource Adequacy

Processes and standards for system reliability are executed through the NYISO's coordination efforts with transmission owners, the New York State Reliability Council (NYSRC), the New York State Public Service Commission (NYPSC), the Northeast Power Coordinating Council (NPCC), and NERC. The NYISO fulfills its responsibilities under tariffs regulated by the Federal Energy Regulatory Commission (FERC).

The NYSPSC is the commission of the state of New York that regulates and oversees the electric, gas, water, and telecommunication industries.[51] Among other authorities, the NYPSC is responsible for the following areas, all of which are related to resource adequacy (**Table 16**).

Table 16: New York State Public Service Commission (NYPSC) Oversight

Transmission Facilities	Generation Facilities	Reviewing Service Interruptions
The commission must issue a Certificate of Environmental Compatibility and Public Need prior to the operation and construction of an electric transmission line — a "major utility transmission facility" — in the state.[52]	The Siting Board on Electric Generation Siting and the Environment reviews and certifies projects with proposed capabilities larger than 25 MW. The board is comprised from one member from each of the following: the NYPSC, the Department of Health, the Department of Environmental Conservation, NYSERDA, and the Empire State Development Corporation.[53]	The commission is responsible for investigating utility service disruptions

Resource Adequacy and Planning Processes

Capacity Markets

In addition to energy and ancillary service markets, the NYISO has an Installed Capacity (ICAP) market to promote resource adequacy by establishing a forum for the buying and selling of capacity through competitive auctions. The rules by which entities participate in these auctions are detailed in the NYISO's FERC-regulated tariffs. These auctions are conducted on a seasonal and monthly basis. In this market, buyers act in the interest of the consumers to minimize costs, while suppliers and investors benefit from transparent locational pricing and signals that reward or penalize depending on availability and performance.

Importing and exporting wholesale electricity and capacity from neighboring states is an important component of the NYISO's resource mix. Access to a larger pool of resources can provide reliability benefits and strengthen market competition. Capacity imports into New York must meet specific market rules that are similar to those that apply for in-state resources.

In May 2022, FERC approved a series of capacity market enhancements that were proposed by the NYISO, with the support of its stakeholders through the NYISO's shared governance process (NYISO, 2022). The proposal offered a durable resolution between FERC's obligation to protect the NYISO-administered capacity market from buyer-side capacity market power and New York State's authority to address New York's resource mix. The new rules also establish a marginal capacity accreditation market design to improve the accuracy of the capacity values assigned to all capacity supply resources from a resource adequacy perspective. Since the issuance of FERC's order, the NYISO has been engaged with stakeholders to address implementation details associated with the landmark proposal.

Establishing Resource Adequacy Requirements In New York

One critical element of the capacity market is the New York State installed reserve margin (IRM), established annually by the NYSRC.[54] The IRM represents the amount of installed capacity that must exist in the New

51 The department's regulations are compiled in title 16 of the New York Codes, Rules and Regulations and include regulatory authority over 49 electric utilities, as well as some authority over the NYISO.

52 This is pursuant to Article VII of the Public Service Law. Part 102 siting may be utilized in cases when electric transmission lines can be built outside of a complete transmission siting process.

53 Article 10 (passed into law by the governor in 2011) provides additional detail on the siting of generation. See Members of the Siting Board on Electric Generation Siting and the Environment.

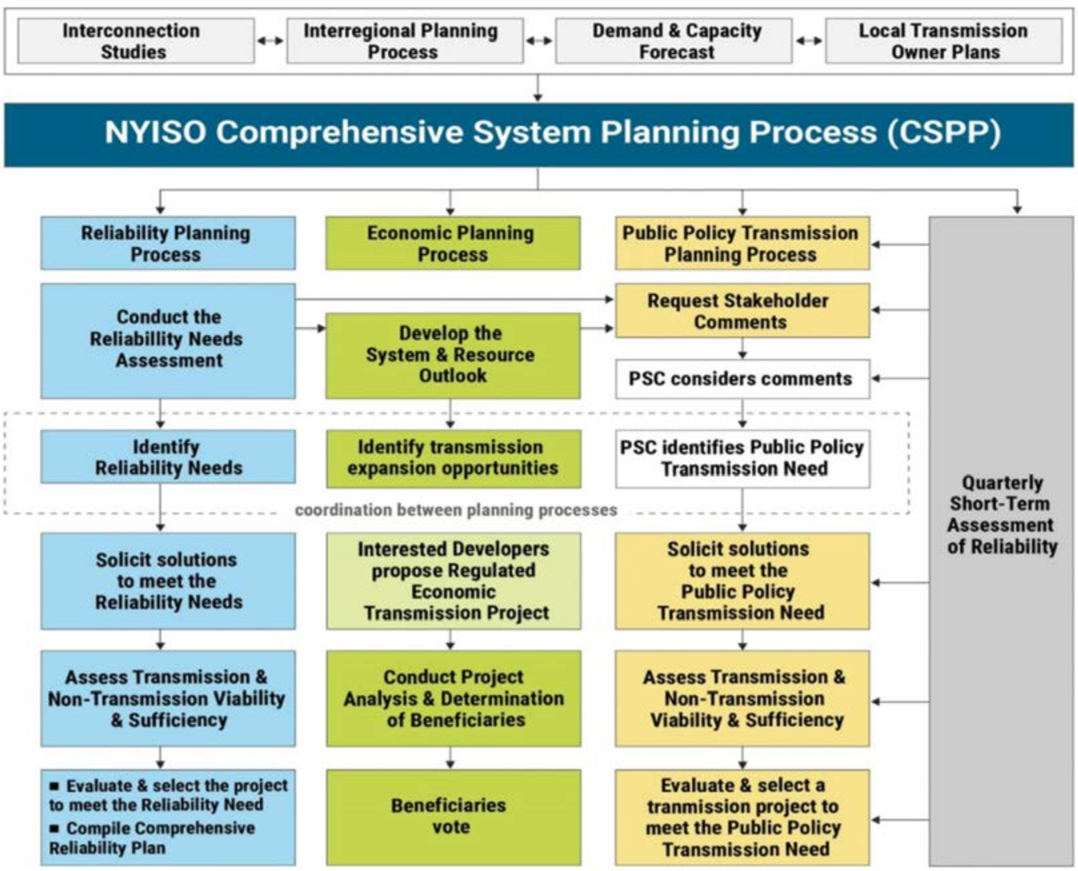
54 The NYISO is responsible for implementing the statewide IRM adopted by the NYSRC, establishing IRM requirements for individual LSEs, and establishing locational requirements for installed capacity in New York City and Long Island.

York Control Area (NYCA) in order to ensure that the applicable resource adequacy reliability criteria are met (NYSRC, 2022). For example, a 20% IRM implies that load serving entities in the NYCA must purchase installed capacity of at least 120% of their projected peak loads. The IRM is applied to the upcoming capability year (May 1 through April 30) and is used to quantify the minimum capacity required to meet the NPCC and NYSRC resource adequacy criterion of a LOLE of no greater than 0.1 days per year. The NYISO, in assisting the NYSRC, uses a probabilistic analysis to evaluate resource adequacy and transmission security against a 0.1 days per year loss-of-load expectation (LOLE) criterion. The analysis considers available capacity, forecasted demand, transmission availability, and other factors. Once approved by the NYSRC, revisions to the IRM are subject to both FERC and NYPSC approval. The IRM for the 2023-2024 capability year is 20% of the forecasted New York Control Area's peak load. The IRM has varied historically between 15% and 20.7%. Reliability planning evaluations, including resource adequacy probabilistic evaluations, are performed by the NYISO under the processes described below.

Planning Process

The NYISO conducts a Comprehensive System Planning Process (CSPP), with the most recent 2022 components and their interplay with other planning processes outlined in **Figure 17**.

Figure 17: NYISO Comprehensive System Planning Process (NYISO, 2022)



The CSP process is conducted every two years and includes four major components that occur in coordination with more frequent (quarterly) Short-Term Assessments of Reliability (STAR):

1. **Local Transmission Planning Process (LTPP):** local Transmission Owners (TOs) perform transmission studies for their transmission areas according to all applicable criteria to produce a Local Transmission Owner Plan (LTP), which feeds into the NYISO's determination of system needs.

2. **The Reliability Planning Process (RPP) and Short-Term Reliability Process (STRP):** The STRP uses quarterly STAR studies and assesses years 1-5. The RPP involves a biennial process for assessing years 4-10, comprised on two separate studies. The two RPP studies provide additional analysis of localized and system-wide reliability needs for the NYISO:

    a. The Reliability Needs Assessment (RNA): System planners prepare this longer-term study on a biennial basis to identify reliability needs for years 4-10. Two major study types — resource adequacy and transmission security — are performed over the RNA study period. This RNA is developed to address any potential risks (e.g., insufficient resources or transmission deficiencies).

    b. The Comprehensive Reliability Plan (CRP). The RNA sets the foundation of the CRP, which integrates all planning studies into a ten-year reliability assessment for the entire New York system. Specifically, the CRP identifies market-based (i.e., efficient or cost-effective) solutions to satisfy any identified reliability needs. Other regulated solutions may be needed in the absence of market-based solutions.

3. **Economic Planning Process (EPP):** involves the development of a System & Resource Outlook, which consists of three study processes:

    a. System & Resource Outlook: A biennial report conducted that summarizes the current assessments, evaluations, and plans in the CSP; produces a 20-year projection of transmission congestion; identifies, ranks, and groups congested elements; and assesses the potential benefits of addressing the identified congestion.

    b. Transmission Project Evaluation (ETPE): The NYISO will conduct this analysis if a developer proposes a Regulated Economic Transmission Project (RETP) to address constraints on the transmission system

    c. Requested Economic Planning Study (REPS): The NYISO will conduct this study at the request of a market participants or other interested party (at their expense) solely for information purposes, which scope and deliverables will be agreed upon by the NYISO and the requesting entity.

4. **Public Policy Transmission Planning Process:** The NYPSC identifies transmission needs driven by "Public Policy Requirements." The NYISO invites interested entities to submit proposed solutions to address the identified needs. NYISO evaluates the viability and sufficiency of the proposed transmission solutions to select proposals that are most efficient or cost-effective. The NYISO develops the Public Policy Transmission Planning Report with findings regarding the proposed solutions.

In concert with these components, interregional planning is conducted with NYISO's neighboring control areas in the United States and Canada under the Northeastern ISO/RTO Planning Coordination Protocol. NYISO's planning processes evaluate current and forecasted resource adequacy and transmission security conditions across the system. The NYISO also conducts an annual area review of resource adequacy of New York's bulk power system, as required by the NPCC. Specifically, a comprehensive review of resource adequacy for the upcoming five years is required every three years. In the two interim years between these comprehensive reviews, individual Planning Coordinators conduct their respective annual interim reviews of resource adequacy that will cover, at a minimum, the remaining years of the five-year period studied in the comprehensive review of resource adequacy.

NYISO Gold Book

The resource adequacy and transmission studies in the RNA are developed using data that is published annually in the NYISO's Load & Capacity Data Report, commonly referred to as the "Gold Book."(NYISO, 2022) The Gold Book publishes 30 years of projections for energy and peak demand forecasts for each NYISO Load Zone. Generating capacity projections are also provided for 10 years ahead. The Gold Book includes historical and forecast seasonal peak demand, energy usage, energy efficiency, electrification, and other distributed energy resources and load-modifying impacts. Finally, the Gold Book provides information on all existing and proposed generation and other capacity resources, and well as existing and proposed transmission facilities.

Resource Adequacy Reforms and Reliability Issues

The NYISO releases a Power Trends report on an annual basis to identify various factors shaping New York's complex electric system. The report also provides important information and unbiased analysis to examine the current electric system, as well as emerging issues and potential actions needed to address future risks. Finally, the report offers the NYISO's perspective on the electric system in response to current or proposed public policy initiatives that may impact or accelerate system changes.

The 2022 Power Trends report included the following key messages:

- The NYISO has established new market rules that advance the state's clean-energy policies. Wholesale electricity markets are open to significant investment in wind, solar and battery storage.
- The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Reliability margins are shrinking. Generators needed for reliability are planning to retire. Delays in the construction of new generating resources and transmission, higher than expected demand, and extreme weather could threaten reliability and resilience in the future.
- A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. These attributes are critical to a dynamic and reliable future grid.
- A historic level of investment in transmission and clean energy supply is underway. Several transmission projects are under construction, setting great expectations that New York's transmission system will meet the clean energy needs of the future. These efforts will deliver more clean energy to consumers while enhancing grid resilience and reliability. Although this new transmission is being built, more investment is needed to support the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway.

NYISO's most recent RNA, issued in December 2022, did not identify a reliability need and concludes that the power grid is expected to meet all applicable reliability criteria through 2032. However, the report emphasizes that already-thinning reliability margins could be eliminated altogether based on identified risk factors, including delays in planned infrastructure investments, more extreme weather, or unexpected generator outages or retirements. Key findings from the 2022 RNA include:

New York City Planning Margins
New York City faces the greatest risk from limited generation and transmission, with reliability margins projected at just 50 MW in 2025.

The Champlain Hudson Power Express (CHPE) HVDC project,
The construction of this project is underway with a proposed in-service date of 2026. The transmission line will deliver renewable power from Hydro Quebec to New York City. If CHPE is delayed, the absence of this resource could result in risks to reliability as soon as 2028.

Extreme Weather
Extreme weather events such as heat waves, cold snaps, or gas shortages could result in deficiencies to serve demand statewide, especially in New York City. This outlook could improve as more resources and transmission are added to the system, beyond what is currently planned.

Increased Electrification

As the NYCA transitions to intermittent generation and public policies encouraging greater electrification result in increased demand, at least 17,000 MWs of fossil-fuel generating capacity may be needed in 2030 in order to reliably supply electricity on high demand "peak" days.

Additional Information on Resource Adequacy in New York ISO

- About the NYISO (Link)
- 2022 Reliability Needs Assessment (RNA) – NYISO (Link)
- How the Installed Reserve Margin Supports Reliability in New York – NYISO (Link)
- Reliability Planning Process and Declaring a Reliability Need: Next Steps – NYISO (Link)
- PSC Initiates Review of New York's Resource Adequacy Programs – New York Public Service Commission (Link)
- Qualitative Analysis of Resource Adequacy Structures for New York – Prepared by the Brattle Group for NYSERDA and NYSDPS (Link)
- 2021-2030 Comprehensive Reliability Plan – NYISO (Link)
- NYSRC New York Control Area Installed Capacity Requirement Reports – NYSRC (Link)

PJM Interconnection

Area Summary: PJM is a regional transmission organization (RTO) and balancing authority that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. Some states in PJM are restructured (that is, they allow retail competition), whereas others are vertically integrated. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid. PJM also administers a regional transmission planning process.

States: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia

Regional Reliability Authorities: Reliability First (RF); Midwest Reliability Organization (MRO); SERC Reliability Corporation (SERC)

State Commission(s): Delaware Public Service Commission, Illinois Commerce Commission, Indiana Utility Regulatory Commission, Kentucky Public Service Commission, Maryland Public Service Commission, Michigan Public Service Commission, New Jersey Board of Public Utilities, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utility Commission, Tennessee Public Utility Commission, Virginia State Corporation Commission, Public Service Commission of West Virginia, and the Public Service Commission of the District of Columbia

Forums for Regulatory Involvement in Resource Adequacy & System Planning: Organization of PJM States, Inc. (OPSI)

Entities Involved in Resource Adequacy and Planning

In the PJM region, states work with utilities and PJM to understand the resource adequacy needs of the region. However, it is ultimately the states that retain the fundamental responsibility to maintain resource adequacy in their jurisdictions in compliance with applicable federal reliability standards. To carry out this responsibility cost-effectively, states have recognized that utility participation in RTOs holds potential cost savings for consumers by sharing capacity. These savings are primarily created by resource diversity and geographical diversity. But RTO participation is voluntary. RTOs are merely a tool states can use to maintain electric quality standards in their jurisdiction cost-effectively. When FERC approved PJM as an RTO, the Commission found that allowing LSEs to set the region-wide reliability requirement was inconsistent with Order No. 2000's independence principle and required PJM to transfer this responsibility to the PJM Board of Managers. Importantly, the Commission noted that this finding was not intended to intrude upon the states' traditional role in setting generation reserve requirements for load serving entities".

Like in other regions, states in the current PJM region formed public service commissions in the early 20th century, in part, to regulate vertically integrated electric companies. States, determining electric utilities exhibited characteristics of a natural monopoly, grant commissions the authority to regulate utility profits and impose service obligations and service quality standards. In 1927, three utilities recognizing that excess capacity would exist following the development of a large hydroelectric facility in northern Maryland formed a power pool to develop transmission and share power, which allowed them to defer additional generation investment. By the 1960s, the power pool's territory expanded to Maryland, and PJM planners began using probabilistic methods to determine a 1-event-in-10-year LOLE for the region. A PJM committee made up of utility members set the installed reserve margin based on PJM's analysis. Beginning in 1974, PJM imposed a two-year-forward capacity obligation on member utilities, and PJM allocated the total capacity requirement across the power pool, requiring each utility to demonstrate that it would have sufficient installed capacity to satisfy this requirement or pay a deficiency charge.

With the introduction of retail choice in many Mid-Atlantic states in the late 1990s and early 2000s, PJM introduced a daily capacity obligation, supplemented by daily and monthly capacity credit markets, to allow LSEs to buy and sell capacity obligations as customers changed retail suppliers. This capacity construct led to generally low and occasionally volatile capacity prices which did not, in coordination with energy and ancillary services market revenues, incentivize the entry of new generation, leading to reliability challenges in the early 2000s. This led to the development and implementation of PJM's current capacity market construct in 2007.

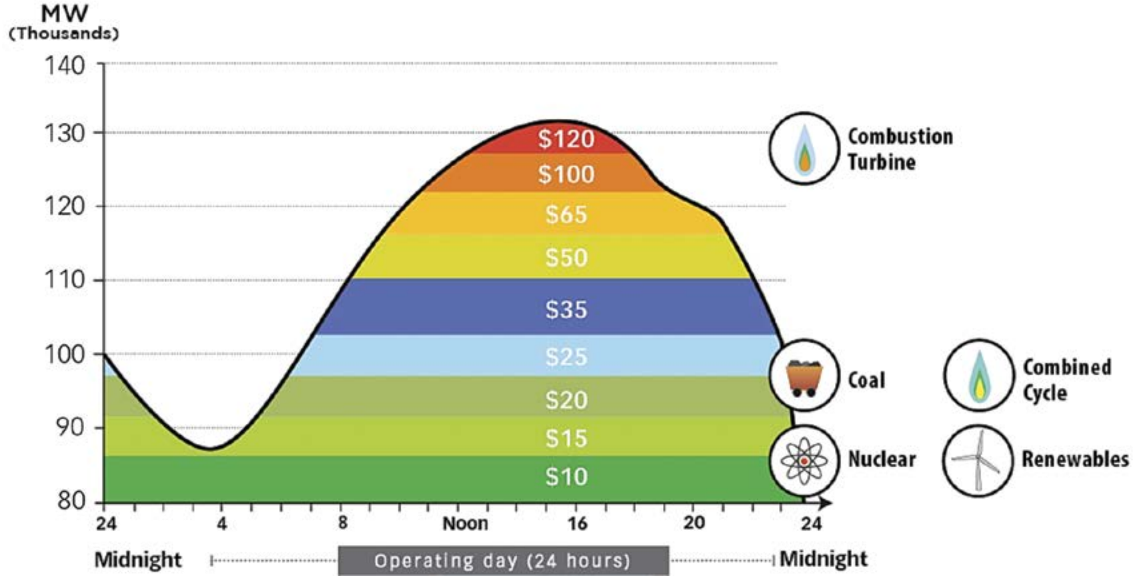
Resource Adequacy and Planning Processes

PJM conducts day-ahead energy auctions to commit adequate resources to provide energy to the electric grid in each hour for the following day based on the forecasted demand of its utilities and competitive providers that serve customer load (collectively, "load-serving entities"). PJM then conducts follow-up spot energy auctions for each five-minute interval of the operating day to dispatch the most economic energy needed to reliably balance actual load and generation in real time. All resources with bids at or below the energy clearing price receive the clearing price. **Figure 18** illustrates that the quantity and type of resources economically dispatched in PJM's energy markets changes during the day.[55]

To ensure that there is sufficient energy when customers need it, PJM requires LSEs procure capacity equal to their forecasted load plus a reserve margin in advance of each delivery year. An LSE can either participate in PJM's capacity auction or submit a plan showing it owns or has contracted for sufficient capacity to meet PJM's reliability requirements. The process and requirements for the capacity auction and the fixed-resource alternative are approved and regulated by FERC (PJM, 2023). The states, however, have the final say over whether to require their LSEs to procure capacity through RMP auctions or to submit an FRR plan.

55 For the subjects discussed in this summary document, PJM's governing documents contain many technical details that are necessarily omitted herein. The source for all pictures in this section is PJM, which has provided permission for their use.

Figure 18: PJM Hourly Energy Illustration (PJM, 2023)



PJM is responsible for conducting analysis to identify the appropriate target reserve margin, and the PJM Board has the responsibility of approving the final reserve margin value. This process satisfies the ReliabilityFirst reliability standards for the PJM region. Following a period of member review, the PJM Board of Managers approves the final reserve margin value. The final reserve margin value is then the basis for defining the RTO Reliability Requirement for use in the Reliability Pricing Model (RPM) Base Residual Auction. States and state Public Service Commissions are not members of PJM and have no formal role in this process. PJM's members, however, are asked to endorse this value as it is developed.

Capacity Accreditation

For RPM auctions and the FRR alternative, PJM determines the capacity values of generation based on the unforced capacity of a resource. For most types of generation, PJM uses a test of the unit's maximum summer performance, de-rated by the expected forced outages (or EFORd) of the unit. For variable, limited duration and combination resources, PJM uses Effective Load Carrying Capability (ELCC). **Table 17** summarizes the methodologies used for generation and demand-side resources (PJM, 2023).

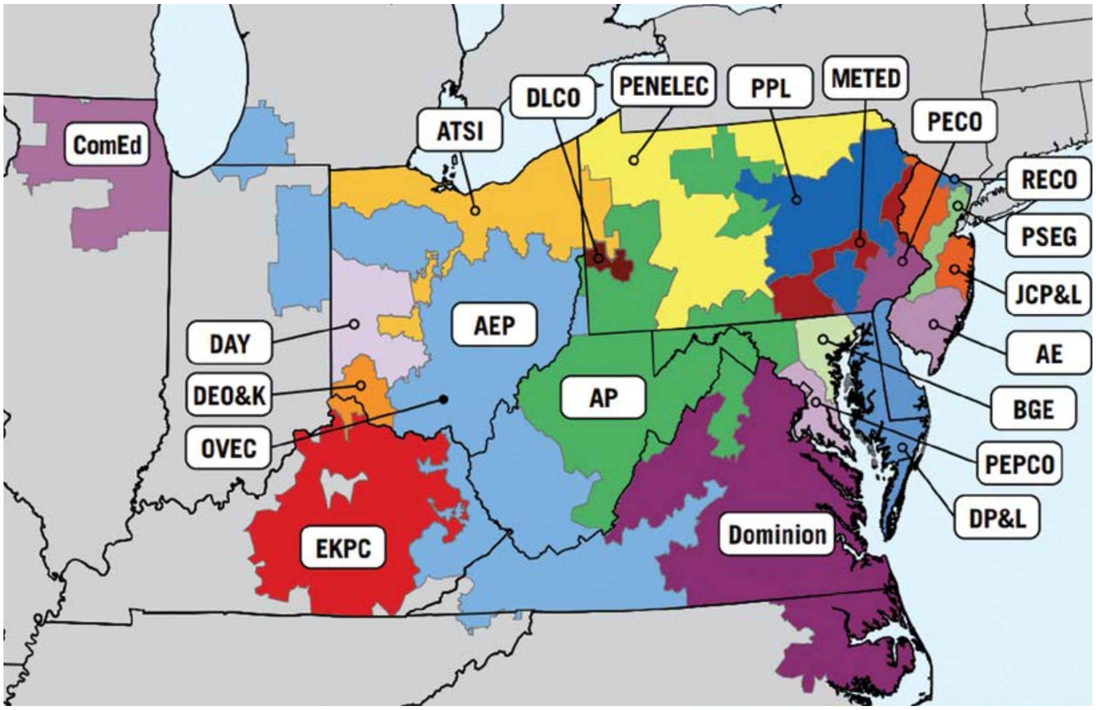
Table 17: Capacity Accreditation Summary

Resource Type	Rated Installed Capacity (ICAP)	Unforced Capacity (UCAP) Conversion
Thermal (i.e., natural gas, steam-powered units)	Summer Net Capability (i.e., maximum dependable output)	ICAP *(1-EFORd)
Demand Response/ Energy Efficiency	Nominated Value	Nominated Value* (1 + The Forecasted Pool Requirement)
Variable (e.g., wind, solar, Limited Duration (i.e., storage <24 hours), Combination (e.g. hydro with non-pumped storage)	N/A	ELCC

Reliability Pricing Model Auctions

PJM's capacity market is called the Reliability Pricing Model, or RPM, and it was first implemented on June 1, 2007. In PJM's RPM auctions, existing and planned supply-side and demand-side resources submit bids. Capacity imports that are deliverable into PJM may also bid into the auction. Resources that clear the auction receive revenues based on clearing prices. Depending on bids and delivery constraints, auction clearing prices can vary by location across 27 subregions (**Figure 19**). This locational aspect of the current construct did not exist prior to 2007, which made it difficult to maintain reliability throughout all parts of the footprint.

Figure 19: PJM Zone Map (Electric Utility Service Territories) (PJM, 2023)



With capacity auction revenues come certain obligations. Cleared generation resources must-offer power into PJM's energy markets.[56] Cleared resources must either perform when called upon to maintain reliability or face monetary penalties. Cleared resources must also conduct tests to verify their capability during summer and winter (PJM, 2023).

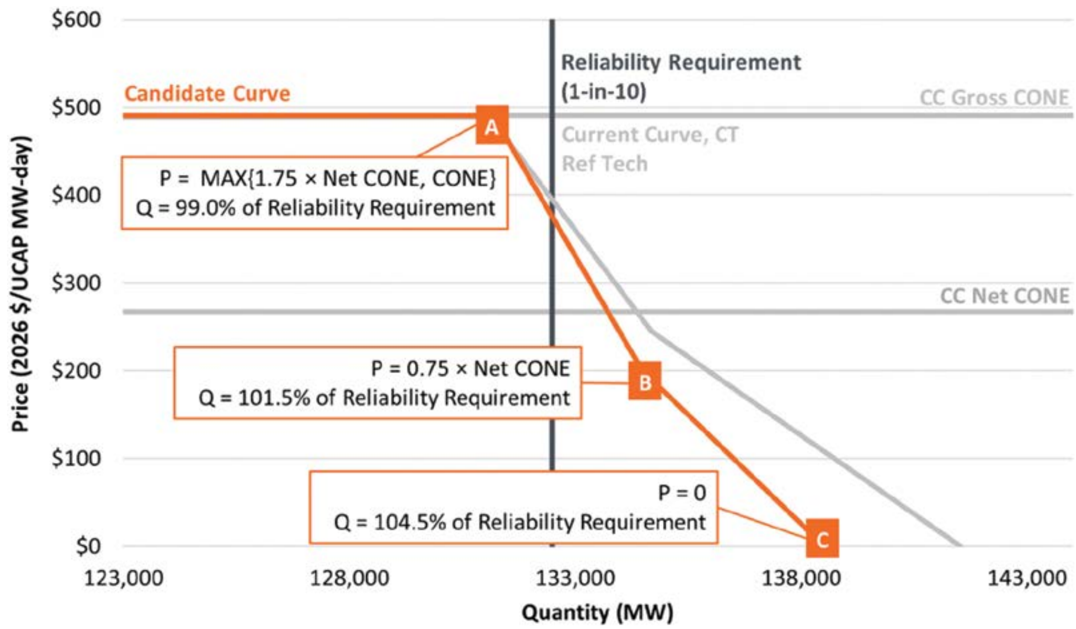
PJM's auctions are run annually to procure capacity requirements for all load in the footprint that is not covered by the FRR alternative. Capacity commitments for cleared resources run from June 1- May 31 of the relevant delivery year and are generally for the delivery year that begins three years after the auction. This initial auction is known as the base residual auction (BRA). In the three years between the auction and the committed year, other incremental auctions are conducted to allow load serving entities to make incremental capacity sales or purchases. However, PJM has not held a BRA three years in advance of a delivery year since May 2018. The next three-year forward auction PJM plans to run will be for the 2029/2030 delivery year.

Although PJM uses a summer peak load forecast and approves an installed reserve margin based on the one-day-in-ten-years loss of load expectation standard, PJM can and does procure capacity beyond the target

56 All of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller. Participation by Load Serving Entities (LSEs) in the RPM for load served in the PJM region is mandatory, except for those LSEs that have elected the Fixed Resource Requirement (FRR) Alternative. Effective for the 2018/2019 and subsequent delivery years, all capacity resources are subject to the must offer requirement, with the exception of intermittent and storage resources which are categorically exempt from the must offer requirement. Capacity Storage Resources include hydroelectric, flywheel and battery storage. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources.

in recognition of added reliability contribution of the additional capacity. For each auction, PJM creates a downward sloping demand curve using the installed reserve margin and the cost of a new generator to enter the market (i.e., cost of new entry) as inputs. These parameters tell PJM how high the curve should start and how steeply it should decline to $0. This administratively determined demand curve is called the Variable Resource Requirement (VRR) Curve. The auction clearing price and quantity of capacity procured is determined by the point where the supply curve of bids intersects with the VRR Curve. **Figure 20** illustrates a recent change to PJM's administrative demand curve's design, with formulas for creating each defined point, which adopts a combined cycle gas turbine (CC) as the reference technology and shows a steeper downward curve in comparison to the current curve.[57] FERC found the revised VRR Curve meets reliability requirements, at reasonable cost, while also incentivizing investment in new generation (Spees et al., 2022).

Figure 20: Variable Resource Requirement Curve Shift Comparison (Spees et al., 2022)



If PJM procures installed capacity more than a percentage point below the IRM or identifies transmission delivery violations after the BRA, PJM can request that FERC authorize additional reliability backstop auctions to procure additional capacity to resolve the reliability criteria violations that triggered the need for the backstop auction. Subject to FERC approval, PJM may modify the VRR parameters for reliability backstop auctions.

The Fixed Resource Requirement Alternative

LSEs may also use a Fixed Resource Requirement (FRR) plan to meet a fixed capacity resource requirement instead of having PJM procure capacity on their behalf through the RPM. Under this alternative, the load-serving entity must demonstrate to PJM that it has enough resources to cover its entire projected load, plus the PJM determined reserve requirement. The FRR entity can use resources that are owned or contracted, existing or planned, supply-side or demand-side. Like auction-cleared resources, resources included in an FRR plan are also subject to energy market must offer requirements and monetary penalties if they fail to perform when called upon to maintain reliability. By submitting an FRR plan, an FRR entity removes its entire load and the specified resources from PJM's capacity market auctions. Such an entity may return to the auction process after five years.

57 Per PJM Interconnection, 182 FERC ¶ 61,073 at P 4 (2023) (2023 VRR Curve Order), PJM is required by its Open Access Transmission Tariff to review the RPM auction parameters every four years. For its fifth quadrennial review, PJM and its stakeholders reviewed the Variable Resource Requirement (VRR) Curve and its parameters for the 2026/2027 Delivery Year.

Resource Adequacy Reforms and Reliability Issues

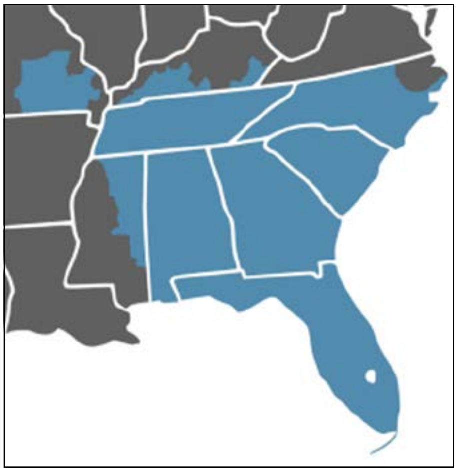
In 2021, PJM convened capacity market workshops with its stakeholders and FERC conducted a technical conference on resource adequacy. After PJM's workshops concluded, the chairman of the PJM Board of Managers, on behalf of the PJM Board, requested that PJM stakeholders advance discussions about modifying the capacity auction bid floors through an accelerated stakeholder process to achieve consensus in time for PJM to potentially file proposed changes with FERC. PJM's Markets and Reliability Committee chartered the Resource Adequacy Sr. Task Force in the fall of 2021 with an issue charge to guide the Task Force's work.

PJM also released a 2023 report, Energy Transition in PJM: Resource Retirements, Replacements and Risks, which brought several reliability elements into focus. Building on the work of the Task Force, the PJM Board also initiated a process—the Critical Issue Fast Path—for the purpose of soliciting stakeholder proposals to resolve key issues believed to have direct reliability benefits. The PJM Board established a work plan and set a goal of filing a proposal with FERC by October 2023.

Additional Information on Resource Adequacy in the PJM Interconnection

- PJM – *Energy Transition in PJM: Resource Retirements, Replacements and Risks* (Link)
- *Resource Adequacy Planning in PJM*— PJM (Link)
- *PJM Board Gives Direction on Resource Adequacy Market Reforms Filing* – PJM (Link)
- *Critical Issue Fast Path - Resource Adequacy* – PJM (Link)
- *2022 PJM Reserve Requirement Study* – PJM (Link)
- *PJM, Stakeholders Begin Accelerated Resource Adequacy Reform* – PJM (Link)

Southeast (Non-Market)



Area Summary: The Non-Market Eastern Interconnection (Southeast) is the area in the Eastern Interconnection bound by the Southwest Power Pool (SPP), the Midcontinent ISO (MISO) and the PJM Interconnection (PJM). The footprint aligns loosely with the SERC Reliability Corporation (SERC), the Regional Entity designated by the NERC for this area. SERC consists of 36 balancing authorities (BAs), 28 planning authorities, and six reliability coordinators. The BAs include vertically-integrated, investor-owned utilities (IOUs), as well as public power entities, a collection of independent power producers, and the Tennessee Valley Authority (TVA), a federal power marketing authority: Some of the BAs in the SERC use MISO or PJM as their reliability coordinator. For assessment purposes, apart from the MISO and PJM areas, SERC can be split into four subareas, described below.

SERC-Central

States: includes all or parts of Alabama, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, Tennessee, and Virginia

Population: 20 million

Regional Reliability Authorities: SERC Reliability Corporation (SERC)

State Commission(s): Alabama Public Service Commission, Georgia Public Service Commission, Iowa Utilities Board, Kentucky Public Service Commission, Mississippi Public Service Commission, Missouri Public

Service Commission, Oklahoma Corporation Commission, Tennessee Public Utility Commission, Virginia State Corporation Commission

Forums for Regulatory Involvement: SERC Resource Adequacy Working Group and other stakeholder groups in each subarea.

SERC-East

States: North Carolina and South Carolina

Population: 15 million

Regional Reliability Authorities: SERC Reliability Corporation (SERC)

State Commission(s): North Carolina Utilities Commission and South Carolina Public Service Commission

Forums for Regulatory Involvement: SERC Resource Adequacy Working Group and other stakeholder groups in each subarea.

SERC-Florida Peninsula

State(s): a majority of Florida

Population: 22 million

Regional Reliability Authorities: SERC Reliability Corporation (SERC)

State Commission(s): Florida Public Service Commission

Forums for Regulatory Involvement: SERC Resource Adequacy Working Group and other stakeholder groups in each subarea.

SERC-Southeast

State(s): includes all or parts of Alabama, Florida, Georgia, and Mississippi

Population: 16 million

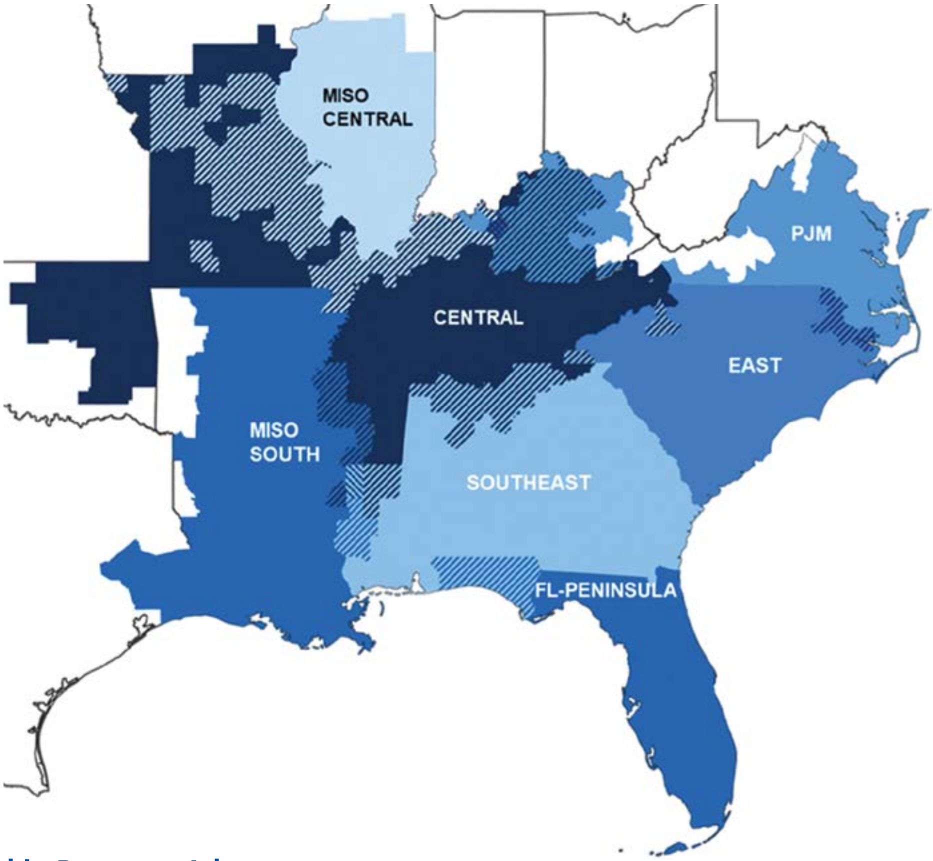
Regional Reliability Authorities: SERC Reliability Corporation (SERC)

State Commission(s): Georgia Public Service Commission; Alabama Public Service Commission, Mississippi Public Service Commission, Florida Public Service Commission

Forums for Regulatory Involvement: SERC Resource Adequacy Working Group and other stakeholder groups in each subarea.

SERC bases their subareas (also referred to as subregions) based on NERC's assessment areas (based on existing ISO/RTO footprints or based on individual Planning Coordinator or group of Planning Coordinators in areas where ISO/RTOs are not established). A more detailed map of the SERC subareas (**Figure 21**) includes additional subareas with member companies that fall under SERC for compliance with NERC Reliability Standards but participate in PJM or MISO markets. These subregions (MISO Central, MISO South, and PJM) are excluded from this section.

Figure 21: SERC Subregions



Entities Involved in Resource Adequacy

SERC-Central

The BAs within SERC-Central include vertically-integrated and investor-owned utilities (IOUs), as well as public power entities, a collection of independent power producers, and a federal power marketing authority: the Tennessee Valley Authority (TVA). Some of the BAs in the SERC-Central designate MISO or PJM as the Reliability Coordinator. The SERC-Central subregion includes the following member companies: Associated Electric Cooperative, Inc. (AECI), Brookfield/Smoky Mountain (SMT), Louisville Gas & Electric and Kentucky Utilities (LG&E/KU), Memphis Light, Gas and Water Division (MLGW), Nashville Electric Service (NES), Owensboro Municipal Utilities (OMUA), and Tennessee Valley Authority (TVA) (SERC, 2023).

SERC-East

The SERC-East area includes utilities that operate within the SERC Regional Entity and includes South Carolina and most of North Carolina. The SERC-East subregion includes the following member companies: The member companies in this subregion include: Cube Hydro Carolinas-Yadkin Division (YAD), Duke Energy Carolinas (DUK), Duke Energy Progress-Carolina Power & Light (DEP, CP&LE, CP&LW), Dominion Energy South Carolina (DESC, SCEG), South Carolina Public Service Authority (SCPSA), and Southeastern Power Administration (SEPA) (SERC, 2023). The VACAR South RC was established through a contractual arrangement between the participating companies and "VACAR South" is registered with SERC as the Reliability Coordinator for the territories of the participating companies in SERC-East.

SERC-Florida Peninsula

The Florida Reliability Coordinating Council (FRCC) is a Reliability Coordinator and Planning Authority in Florida. The FRCC's stated mission is to coordinate a safe, reliable, and secure bulk power system for its members. While the FRCC was originally the Compliance Enforcement Authority in Florida, on July 1, 2019, the SERC Reliability Corporation took over responsibility as the Compliance Enforcement Authority for all electric utilities previously registered with the FRCC as designated by NERC.[58] Within the SERC Peninsula Florida region, the Florida Public Service Commission (FPSC) regulates Florida's electric utilities subject to its jurisdiction. The FPSC's role is to ensure that Florida's consumers receive their most essential services in a safe, efficient, and reliable manner while also balancing the needs of the entities under its jurisdiction. As such, the FPSC oversees the planning and ratemaking considerations of these entities. The SERC-Florida Peninsula subregion includes the following member companies: City of Homestead (HST), City of Tallahassee (TAL), Duke Energy Florida (DEF), Florida Municipal Power Agency (FMPA), Florida Power & Light (FPL), Florida Reliability Coordinating Council, Inc. (FRCC), Gainesville Regional Utilities (GRU), JEA, Lakeland Electric (LAK), Orlando Utilities Commission (OUC), Seminole Electric Cooperative (SEC), and Tampa Electric Company (TEC) (SERC, 2023).

SERC-Southeast

The vertically-integrated investor-owned subsidiaries of the Southern Company operate across the SERC-Southeast subregion, with various municipal utilities and electric membership cooperatives (EMCs) interspersed throughout the region. The SERC-Southeast subregion includes the following member companies: Georgia Transmission Corporation (GTC), Municipal Electric Authority of Georgia (MEAG Power), PowerSouth Energy Cooperative (PS), and Southern Company (SOCO) (SERC, 2023).

Resource Adequacy and Planning Processes

SERC-Central

There is no single resource adequacy standard or process for BAs in SERC-Central. States in this region have largely maintained retail jurisdiction and are responsible for determining the resource adequacy standard or method for jurisdictional utilities, with the exception of TVA. Most state commissions allow each jurisdictional utility to independently establish its resource adequacy method through integrated resource plans (IRPs), or other planning or modelling processes. Depending on its statutory authority, the state commission may receive, approve, or simply acknowledge the IRP from a utility, as well as its corresponding resource adequacy methodology. For example, the Kentucky Public Service Commission (KPSC) has jurisdiction over IOUs and rural electric cooperatives and reviews each utility's IRP. The KYPSC also reviews staff reports with recommendations for subsequent IRPs based on the sufficiency of the current version. Although the KYPSC does not enter substantive orders on a utility's IRP, there are opportunities to present information through hearings, intervention, and discovery. In other states, commission jurisdiction may not extend to municipal utilities, cooperative distribution cooperatives, generation and transmission cooperatives, TVA distribution cooperatives, and/or independent power producers.

Under state IRP processes in the SERC-Central area, utilities develop multi-year plans every two-to-four years, and engage in stakeholder processes to review forecasting, modeling and analysis of demand, resource performance, and the utilities' proposed portfolio during the next 10-20 years. This includes consideration of any specific state-mandated analysis. Stakeholders involved in the IRP process include commission staff, residential, commercial, and industrial consumer advocates, environmental advocates, and other interested citizens. TVA typically introduces a new IRP every five years and describes its IRP process as follows:

> *An IRP serves as a compass for how to best meet forecasted energy demand in the coming decades. The comprehensive study includes TVA describing resource needs, policy goals, physical and operational constraints, risks, and proposed resource choices. Stakeholders are involved throughout the process, reviewing the planning information, and shaping the analysis and outcomes (TVA, 2023).*

As a federally-owned utility, TVA is not subject to state commission oversight, and the entirety of load-serving entities, which TVA refers to as local power companies (LPCs), are subject to the results of TVA's IRP and related

58 The FRCC remains a member services organization in Florida.

planning decisions. This is a result of wholesale power agreements between the respective LPCs and TVA. Given its federal status, TVA's IRP-related resource decisions are subject to the National Environmental Policy Act, providing a greater layer of scrutiny and review.

Utility BAs generally meet resource needs through owned generation, bilateral contracts, and Purchase Power Agreements (PPAs). Many utilities currently rely on PPAs to meet a portion of their peak load, with IRPs used by the applicable utility to identify the volume of short-term purchases. In addition to state requirements, SERC conducts annual resource adequacy assessments of each subregion, using a 15% PRM target (i.e., reference margin level).

Utilities and BAs in the region use a variety of methods to establish resource adequacy targets and to set their planning reserve margins. These generally fall into one of two methods: deterministic or probabilistic. Deterministic methods, such as those used by SERC in its yearly resource assessment, generally plan around a single peak hour and add a fixed amount of planning reserves to the resources needed to meet that peak hour. Deterministic planning reserve margin standards are based on historical and expected loads and resource performance during previous peaks.

Individual utilities typically use a probabilistic method in their analysis when conducting IRPs. The probabilistic approach includes variations in load, generation performance and outage assumptions, weather, and other factors in an hourly model that examines and produces a distribution of potential outcomes during the assessment period. Outages throughout the system are modeled as random, based on a number of scenarios (referred to as a Monte Carlo simulation), also factoring the potential for correlated outages. Resources are added to the model as needed to reach the desired level of reliability. Most BAs use a loss-of-load expectation (LOLE) metric to measure the resource adequacy standard. SERC also incorporates probabilistic modeling in its annual assessment, identifying any potential concerns or risks.

SERC-East

SERC is made up of many members that perform their own internal studies and participate in studies under the direction of the SERC Engineering Committee. Some entities have performed studies to evaluate the fuel resiliency of all generating assets in their portfolio, including fuel supply, fuel delivery, inventory, and backup contingencies to determine the potential impact fuel diversity has on the Planning Reserve Margin. These studies suggest that SERC's overall fuel supply position is among the most resilient in the United States due to a well diverse generation portfolio, advantageous location with respect to major natural gas pipelines, access to multiple coal supply and transport options, and a strong and resilient program to secure nuclear fuel.

SERC-Florida Peninsula

Florida's electric utilities typically develop load forecasts as part of the annual system planning and budgeting cycle, relying on in-house forecasting teams. Utility forecasting methods are unique to each utility, but typically include statistical modeling and surveys. To accurately account for a variety of factors influencing electric usage over the planning horizon, utilities develop a set of econometric models to forecast the number of customers (by customer class), average energy usage (by customer class), energy sales, and summer/winter peak demand. These models include a variety of economic, demographic, and weather variables. Other impacts to electricity demand, including the adoption of plug-in electric vehicles, behind-the-meter generation (e.g., rooftop solar), and regulatory/federal policy changes, may be either incorporated in the models or represented as exogenous adjustments to the resulting forecasts. The impact of building codes, appliance efficiency standards, and appliance saturation via end-use models may also be incorporated as forecast adjustments. The utilities' demand forecasts also include impacts of demand-side-management programs. Survey methods or trending models are often used for generating the load forecasts of specialty classes, such as public authorities and lighting customers. The utilities' individual load forecasts are combined by the FRCC into system and statewide forecasts, then reviewed by the FRCC Load Forecasting Working Group before finalization.

After the load forecast is developed, Florida's electric utilities must determine what generation or transmission resources will be necessary to meet their reliability needs. Each utility considers its existing and projected generation and transmission resources, according for planned retirements, purchased power agreements, and other resource commitments or limitations, to determine what resources, if any, are necessary to meet each utility's reliability planning requirements. Individual resource plans (for both generation and transmission) from each utility are combined by the FRCC with consideration for non-utility resources and other modifications to account for system reliability needs. System peak contributions for non-dispatchable resources (e.g., rooftop solar) are considered primarily for summer peak demand, but at least one utility attributes some capacity for winter peak demand purposes.

Under Florida's regulatory construct, each electric utility is responsible for planning sufficient resources to meet its reliability needs, and does so by coordinating with the FRCC, with oversight of the FPSC. The FPSC annually reviews Ten-Year Site Plans (TYSP) and non-binding planning documents from all generating electric utilities with existing capacity equal to or greater than 250 MW, or with plans to construct 75 MW or more planned capacity (Florida, 2023). Reporting utilities that meet these requirements accounted for approximately 98% of Florida's retail energy sales as of 2022. The TYSPs of Florida's electric utilities are the culmination of an integrated resource plan (IRP) which is designed to give state, regional, and local agencies advance notice of all proposed power plants and transmission facilities, as well as planned retirements. The FPSC receives comments from these agencies and attaches them to the FPSC's final report. The FPSC also holds a workshop for involved utilities to present a summary of their plans to the Commission, collect public feedback, and address questions.

Following the filings and workshop, FPSC staff perform a preliminary study of each TYSP and submit a nonbinding report, which includes a recommendation to Commissioners as to whether each of the utility's TYSP should be deemed suitable or unsuitable for planning purposes. The Commissioner's votes determine the final suitability determination of these plans. As the TYSPs are non-binding documents, separate certification proceedings are required under the Florida Electrical Power Plant Siting Act (PPSA) or the Florida Electric Transmission Line Siting Act (TLSA) for any generation and transmission facilities identified as necessary by a utility under the FPSC's jurisdiction. The FPSC is the exclusive forum for the determination of need for these facilities (Florida, 2023). Any facilities that are not subject to either the PPSA or the TLSA, are addressed by the FPSC in ratemaking proceedings for the investor-owned utilities.

Florida's electric utilities use multiple indices to determine the reliability of their electric supply. The FPSC requires electric utilities to maintain a minimum planning reserve margin (PRM) of 15% (Florida, 2021). The three investor-owned electric utilities in Florida (Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company) represent 70% of statewide retail energy sales and are required by stipulation approved by the FPSC to plan their respective systems using a 20% PRM (FPSC, 1999). Electric utilities may elect to have a higher reserve margin, either on an annual or seasonal basis. Several utilities have also provided generation-only reserve margins (excluding demand response and incremental energy efficiency resources) for evaluation purposes, but these reserve margins have not been approved by the FPSC and are subject to review in future proceedings, as no generating units have been planned solely based upon them. Utilities in Florida also use Loss-of-Load Probability as a reliability metric. However, the reserve margin requirement is typically the determining factor for commission decisions related to capacity additions and retirements.

SERC-Southeast

The vertically-integrated investor-owned subsidiaries of the Southern Company operate across the SERC-Southeast subregion, with various municipal utilities and electric membership cooperatives (EMCs) interspersed throughout the region. The Southeastern Regional Transmission Planning (SERTP) process, initially developed to comply with FERC Order 890, provides a forum to meet planning criteria requirements for member utilities and their agents in the area. While the SERTP stakeholder process is open, it does not directly include state utility regulators in its oversight and decision-making.

Integrated resource planning (IRP), where required, plays a crucial role in providing long-term generation strategies to meet the needs within different service territories. In the state of Georgia, for example, the Georgia Public Service Commission directly regulates the IRP for the state's only investor-owned electric utility, the Georgia Power Company. However, the filings in the Georgia Power IRP reflect broader resource adequacy issues in the state, and across the region. This is because Southern Company conducts system-wide planning across operating companies and co-owns various generation and transmission resources with different types of utilities in the state. For instance, Plant Vogtle nuclear units will be under co-ownership from Georgia Power, Oglethorpe Power on behalf of EMCs, the Municipal Electric Authority of Georgia, and Dalton Utilities.

While Alabama Power and Mississippi Power also conduct IRPs, Georgia Power has the most comprehensive commission-directed IRP process in the SERC-Southeast assessment area. A 20-year plan is filed every three years under Georgia state law, requiring approval from the Georgia PSC following a series of public hearings open to a broad set of intervenors. Load forecasts form a fundamental basis for analyzing the IRP with reliability and modernization considerations to meet load forecasts as critical factors in determining resource additions and retirements. Concurrent with the IRP, the Georgia PSC considers a separate demand-side management docket to incorporate potential load-reduction opportunities. Although the final order from the commission applies to Georgia Power, the IRP impacts resource adequacy in neighboring states and systems.

Peak loads historically occur during the summer due to wide-spread use of air conditioning. However, increasing peak demand during the winter has emerged as a potential reliability challenge for system planners since the 2013-2014 Polar Vortex. The Reserve Margin Study is conducted to determine the target reserve margin (TRM) across Southern Company's system in Georgia, Alabama, and Mississippi. Beginning with the 2018 Reserve Margin Study, Southern Company has identified specific risks to capacity during the winter months, leading the Georgia PSC to approve a higher TRMs for the winter season.

Resource Adequacy Reforms and Reliability Issues

SERC-Central

Stakeholders have raised concerns about potential policy decisions impacting the maintenance of the current level of resource adequacy. For example, as utilities and states adopt and move toward a carbon-limited future, how will these changes impact reliance upon coal and natural gas generation used to meet resource adequacy standards? What alternatives are available and how will resource adequacy be impacted by integration of more intermittent resources? Will there be sufficient transmission infrastructure to move the power to the load? Are correlated outages being adequately considered, such as pipeline losses affecting gas generator performance in certain geographic areas?

SERC-East

According to NERC's 2022 Long-Term Reliability Assessment, SERC-East is transitioning from a summer-peaking area to a winter peaking one. This change in peaking is mainly driven by two factors: continued electrification as well as growing solar resources that shave off the summer peak. Probabilistic Base Case results indicate a trend of growing risk during winter morning hours when solar resource capacity is low. The assessment results for year 2026 indicate that the reliability metrics during January morning hours degrade as solar resources grow. As SERC-East transitions to peaking in winter, the growth in solar capacity projected for 2026 helps reduce loss of load risk during summer hours (NERC, 2022).

SERC-Florida Peninsula

Every year, the FPSC evaluates both the individual utility TYSPs and the State as a whole. In its most recent evaluation, the FPSC identified the following trends in its statewide perspective that relate to resource adequacy:

Battery Storage

The reporting Florida IOUs are currently operating and plan to expand battery storage technology over the next 10 years due to declining costs, operational characteristics, scalability, and siting flexibility. In addition to utility-owned battery storage, energy storage associated with purchased power agreements are also anticipated in the current planning horizon. The impact of these non-traditional capacity resources on the reliability of the Peninsular Florida region will continue to be evaluated in the next few years.

Electric Vehicle Charging Infrastructure

Florida's electric utilities anticipate continued growth in the EV market, as EV ownership is anticipated to grow rapidly. The major drivers of this growth include increased availability of charging infrastructure, lower fuel costs and emissions, increased commitment from auto manufacturers, broadened public outreach, expanded vehicle availability (makes and models), and strong government policy support at the local, state, and federal levels. The Florida Legislature required the FPSC and State Energy Office to assist the Florida Department of Transportation in developing and recommending a master plan for the development of EV charging station infrastructure along the Florida State Highway System, resulting in the EV Infrastructure Master Plan, published in July 2021. Government agencies, private entities, municipalities, and electric utilities continue to work together to expand charging infrastructure throughout the state of Florida to meet this expected growth in EVs, as well as to promote EV ownership.

Solar Integration

The majority of installed renewable capacity for Florida's electric utilities is represented by solar photovoltaic generation, which makes up approximately 80% of Florida's existing renewables. Solar generation is projected to be the second highest category of installed capacity by the end of the decade. As the proliferation of solar resources continue, both in total capacity and as a percentage of system generation, planners and operators will continue to monitor system impacts.

SERC-Southeast

SERC-Southeast continues to update and expand its resource portfolio to address load growth. For example, the nuclear units added at Plant Vogtle, as well as solar resource additions have offset the retirement of older coal-fired plants. However, these changes have prompted the need to identify transmission reliability needs in the northern part of Georgia's Integrated Transmission System.[59] While most of Georgia's load is in the northern part of the state, many solar resources are located in southern Georgia, thus requiring new intrastate infrastructure. Interstate transmission is also needed to support the region during extended periods of extreme cold temperatures to help avoid blackouts or other customer-impacting emergency responses. Ensuring resource adequacy remains a significant economic consideration for this growing region.

The 2022-2031 SERC Annual Long Term Reliability Assessment Report also cautioned that the variability of renewable resources, the increases in solar and wind penetration on the system, and the retirement of more dispatchable generation will necessitate reevaluation of the current NERC 15% reference margin level (SERC, 2023). The 2022-2023 SERC Regional Risk Report, within the SERC LTRA, identified three risks impacting resource adequacy within SERC: (1) resource uncertainty and changing resource mix; (2) fuel diversity and fuel availability, and (3) variable energy resource integration. The 2022-2023 Probabilistic Assessment for Resource Adequacy (SERC 2022-2023 Probabilistic Assessment) stated that as coal generation continues to retire, SERC is seeing an increase in natural gas fired generation, which currently makes up over 50% of resources in the SERC Region. Further, the SERC 2022-2023 Probabilistic Assessment noted that extreme weather ranks number five in the top ten SERC Regional risks. Notably, Winter Storm Uri (2021) and Winter Storm Elliott (2022) impacted

59 The Georgia Integrated Transmission System is a jointly owned transmission system operated that serves 90% of the state, including Georgia Power, municipal, and electric cooperative customers.

various parts of the Southeast region, and according to SERC, indicated a need for a regionally coordinated study of the resource adequacy impacts of extreme cold weather events.

While the region successfully responded to the most recent winter weather, it was fortunate that the extreme cold occurred during the holiday season when energy loads are lower. As the region expands its renewable resources, it continues to manage capacity growth. State commissions and their regulated utilities are developing and/or implementing plans to address these challenges. However, utilities may need to develop additional emergency operating plans and/or redundancies to address potential outage risks caused by extreme weather events.

Meeting New Regulatory Challenges

Actions taken by the federal government could have an impact on resource adequacy in this region. As federal and state policymakers focus on carbon mitigation, state utility regulators and LSEs continue to adapt internal planning processes to comply with new requirements. Additionally, rules related to interstate coordination on transmission planning may influence how the Southeast region meets its resource adequacy needs without an organized market.

Southeast Energy Exchange Market

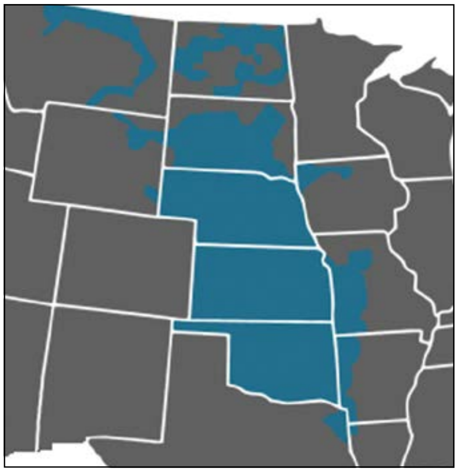
The Southeast Energy Exchange Market (SEEM) is a trading platform that facilitates sub-hourly, bilateral trading, allowing participants to buy and sell power close to the time the energy is consumed, utilizing available unreserved transmission. On October 13, 2021, FERC approved the SEEM, but on July 14, 2023 the United State Court of Appeals for the District of Columbia Circuit remanded the decision back to FERC due to inconsistencies with open access regulations. As of January 1, 2023, members of SEEM included Associated Electric Cooperative; Dalton Utilities; Dominion Energy South Carolina; Duke Energy Carolinas; Duke Energy Florida; Duke Energy Progress; Georgia System Operations Corporation; Georgia Transmission Corporation; JEA; LG&E and KU Energy; MEAG Power; N.C. Municipal Power Agency No. 1; NCEMC; Oglethorpe Power Corp.; PowerSouth; Santee Cooper; Seminole Electric Cooperative; Southern Company; Tampa Electric Company; and TVA. SEEM's footprint includes 23 entities spanning the states of Alabama, Florida, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, South Carolina, Tennessee, and Virginia with more than 180,000 MWs (summer capacity; winter capacity is nearly 200,000 MWs). SEEM members serve the energy needs of more than 36 million retail customers (nearly 60 million people).

Pending ongoing litigation and regulatory action to ensure an open and non-discriminatory program, SEEM could emerge as a new participant established within the region. It should be noted that SEEM is not designed as a capacity market or energy imbalance market. As stated on its website, "The SEEM platform facilitates sub-hourly, bilateral trading, allowing participants to buy and sell power close to the time the energy is consumed, utilizing available unreserved transmission." SEEM may serve as one of several tools the Southeast subregion could further implement to address its resource capacity needs in this growing part of the country.

Additional Information on Resource Adequacy in SERC (Non-Market Southeast)

- SERC Reliability Assessments - Reliability and Planning Studies – SERC (Link)
- *2022-2031 SERC Annual Long Term Reliability Assessment Report* – SERC (Link)

Southwest Power Pool



Area Summary: Southwest Power Pool, Inc. (SPP) is an RTO: a not-for-profit corporation mandated by the FERC to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices on behalf of its members. SPP oversees the bulk electric system and administers a wholesale power market on behalf of a diverse group of electric utilities. SPP has members in 15 central and western U.S. states and provides energy services on a contract basis to customers in both the Eastern and Western Interconnections. SPP has customers in all or part of 23 states and provinces through our western energy services. SPP oversees territory with over 5,180 substations and 949 generation plants, with approximately 72,000 miles of transmission.

State(s): Arkansas, Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming

Regional Reliability Authorities: Midwest Reliability Organization (MRO) and SERC Reliability Corporation (SERC)

State Commission(s): Arkansas Public Service Commission, Colorado Public Utilities Commission, Iowa Utilities Board, Kansas Corporation Commission, Louisiana Public Service Commission, Minnesota Public Utilities Commission, Missouri Public Service Commission, Montana Public Service Commission, Nebraska Public Service Commission, New Mexico Public Regulation Commission, North Dakota Public Service Commission, Oklahoma Corporation Commission, South Dakota Public Utilities Commission, Public Utility Commission of Texas, and the Wyoming Public Service Commission

Forums for Regulatory Involvement: The SPP Regional State Committee (RSC) is composed of retail state regulatory commissioners in the SPP region and is the primary authority to determine its approach to resource adequacy. The SPP - RSC/OMS Liaison Committee was established to facilitate identification of issues and potential solutions to enhance the benefits to customers from better coordinated seams policies.

Entities Involved in Resource Adequacy

Reliability is SPP's top priority, and it is intertwined with other functions that collectively support both reliability and economic benefits. A component of SPP's operations and reliability functions is resource adequacy: the program by which it works with load-responsible entities (LREs) to ensure that they can meet their load obligations. LREs are responsible for ensuring they have access to enough generating capacity to meet their load obligations. They must also satisfy planning reserve margin (PRM) obligations to ensure available capacity is sufficient to serve load at times of peak demand. They must demonstrate compliance with these requirements by identifying their owned resources in a submission as required by SPP's tariff or by procuring the capacity through bilateral contracts.

Aspects of these resource adequacy requirements (RAR) are defined in SPP's Open Access Transmission Tariff, Planning Criteria, and Business Practices. Section 7.2 of SPP's bylaws grant its Regional State Committee (RSC) — composed of retail state regulatory commissioners in the SPP region — primary authority to determine its approach to resource adequacy (SPP, 2023). The RSC operates and exercises official functions, through its bylaws (SPP, 2022). As the RSC reaches decisions on resource adequacy policies or methodologies, the bylaws direct SPP to make corresponding filings with FERC, pursuant to Section 205 of the Federal Power Act. SPP's board of directors, stakeholders, and staff all also play a role in the governance path of its resource adequacy program, and SPP may file its own separate proposal(s) with FERC on resource adequacy matters, even if such matters are addressed by RSC filings.

Resource Adequacy and Planning Processes

An individual LRE's RAR is equal to its summer-season net peak demand plus its PRM requirement. If an LRE fails to meet its RAR, SPP will charge them a deficiency payment based on their capacity shortfall. SPP determines its planning reserve margin through a probabilistic loss-of-load expectation (LOLE) study. The LOLE study calculates SPP's ability to reliably serve its balancing authority area's forecasted peak demand, and it is based on inputs and assumptions SPP develops with input from stakeholders. SPP performs a LOLE study at least every two years, although it may do so more often if it determines additional studies are needed. Currently, SPP ensures the applicable planning year's LOLE does not exceed a 1-day-in-10-year (0.1 day per year) criterion. SPP assigns its PRM to every LRE in its balancing authority area and does not apply zonal or local requirements.

Resource Adequacy Reforms and Reliability Issues

SPP is currently considering new accreditation policies for wind, solar and storage resources. These new policies are based on the Effective Load Carrying Capacity (ELCC) methodology, which determines accreditation based on historical performance and capacity value. There is also an effort underway to define a methodology that accredits conventional resources based on past performance. Demand response is treated as a load-modifier, and SPP validates the level of reduction based on requirements defined in its governing documents (SPP, 2023; SPP, 2018). With advanced loads interconnecting, SPP is working to improve demand response accreditation methodologies. All resources must demonstrate that capacity submitted for resource adequacy is available by meeting the appropriate qualification requirements.

As discussed above, an individual LRE's RAR is based on its summer-season net peak demand plus its PRM requirement. Similarly, SPP's tariff requires LREs to maintain sufficient capacity for the winter season but does not require a deficiency payment penalty for non-compliance with winter requirements. The addition of a winter season RAR, potentially including a separate winter PRM, is currently under consideration in SPP's stakeholder process.

SPP is also considering changes to its methodology for determining its RAR. As noted above, SPP currently determines its RAR through a probabilistic LOLE study that examines the region's ability to serve load during peak demand conditions. In response to the challenges of extreme weather and the characteristics of a rapidly changing resource mix, new loss of load metrics, including Expected Unserved Energy (EUE) and Value of Lost Load (VOLL), are being evaluated. These new metrics may potentially supplement SPP's current LOLE study and assist in determining future RARs.

SPP continuously looks to mature its resource adequacy policies, which were first implemented in 2017. This includes, but is not limited to, addressing outages, accreditation, changes in resource mix, and researching seasonal assessment needs. Due to increased retirements of conventional resources, SPP is seeing a decrease in the capacity headroom it has maintained in past years. This is driving more reliance on renewable generation to meet and maintain the appropriate reliability metrics for resource adequacy. The transition to, and increasing reliance on, different generation types, with their own unique reliability characteristics, is also causing the region to focus on identifying the "reliability attributes" needed from the overall generation mix and how such attributes may be incorporated into future RARs.

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region to focus on identifying the "reliability attributes" needed from the overall generation mix and how such attributes may be incorporated into future RARs.

Additional Information on Resource Adequacy in the Southwest Power Pool

- SPP Resource Adequacy Documents and Processes (Link)
- SPP Supply Adequacy Working Group (Link)
- SPP Regional State Committee (Link)

Western Interconnection (Non-Market)

Area Summary: The Western Interconnection is one of four major electric interconnections serving Canada and the United States. It encompasses the area west from the Rocky Mountains, and includes all or part of 14 states, two Canadian provinces, and Northern Baja Mexico. The Non-market Western Interconnection is served by 37 balancing authorities (BAs) (excluding the California Independent System Operator (CAISO)). These balancing authorities include vertically integrated investor-owned utilities (IOUs), as well as public power entities, a collection of independent power producers, and two federal power marketing authorities: the Bonneville Power Administration (BPA), and the Western Area Power Administration. In terms of reserves sharing groups, the U.S. portion of WECC is comprised of two sub-regions, characterized by similar operating practices: California/Mexico (CAMX) and the Western Power Pool Reserve Sharing Group (WPP-RSG). This section will exclude the CAMX subarea (previously addressed in the California ISO section) and examine the WPP-RSG area are highlighted in the map. This section will also examine resource adequacy approaches in the Western Area Resource Adequacy Program (WRAP) footprint.

State(s): All or part of Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming

Regional Reliability Authorities: Western Power Pool Reserve Sharing Group; Western Resource Adequacy Program (WRAP); Northwest Power and Conservation Council (Council); Pacific Northwest Utilities Conference Committee (PNUCC)

State Commission(s): Arizona Corporations Commission, California Public Utilities Commission, Colorado Public Utilities Commission, Idaho Public Utilities Commission, Montana Public Service Commission, Nebraska Public Service Commission, Public Utilities Commission of Nevada, New Mexico Public Regulation Commission, Oregon Public Utilities Commission, South Dakota Public Utilities Commission, Public Utility Commission of Texas, Public Service Commission of Utah, Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission

Forums for Regulatory Involvement: Western Electric Coordinating Council (WECC); Western Power Pool (WPP); Western Resource Adequacy Program (WRAP); Northwest Power and Conservation Council (Council), Pacific Northwest Utilities Conference Committee (PNUCC); Western Governors Association (WGA); Western Interstate Energy Board (WIEB); Western Interconnection Regional Advisory Body (WIRAB); and the Committee on Regional Electric Power Cooperation (CREPC), a joint committee of WIEB and the Western Conference of Public Service Commissioners

Entities Involved in Resource Adequacy

Entities involved in resource adequacy in the non-market Western Interconnection have generally involved individual state commissions with non-binding coordination efforts through various regional forums. Until 2023, there was no single or shared resource adequacy standards or practices shared among balancing authorities. States have historically been responsible for determining the resource adequacy standard or approach for jurisdictional utilities, and many state commissions choose to allow each utility to independently establish resource adequacy methods within their integrated resource plans (IRPs) or other planning or modelling processes.[60] Depending on its statutory authority, the state commission may approve or simply acknowledge a utility's IRP, including the resource adequacy approach. For example, in Washington state, the Washington Utilities and Transportation Commission, which has jurisdiction limited to IOUs, does not approve, but only acknowledges a utility's IRP (Washington, 2023).

Aside from utility IRPs overseen by state commissions, other forums in the west create opportunities for utility regulators, state energy offices, and others to engage in separate resource adequacy-related studies and processes. Those forums are provided below:

- **Pacific Northwest Utilities Conference Committee (PNUCC):** A committee of investor-owned utilities, consumer-owned utilities, and independent power producers. PNUCC develops an annual Northwest Regional Forecast, which includes an analysis of resource adequacy studies prepared throughout the region (PNUCC, 2023).
- **Northwest Power and Conservation Council (NWPP):** The NWPP was established by the 1980 Northwest Power Act to prepare regional power plans for the four-state region of the Columbia River Basin (Montana, Idaho, Oregon, and Washington), as well as British Columbia, and Alberta. NWPP's Resource Adequacy Advisory Committee publishes an annual Adequacy Assessment for the Northwest region (NWPP, 2023).
- **The Western Electric Coordinating Council (WECC):** One of six NERC Regional Entities that conducts resource adequacy analysis for balancing authorities, or groups of balancing authorities in the Western Interconnection. WECC promotes bulk power system reliability and security and is responsible for compliance monitoring and enforcement and oversees reliability planning and assessments (WECC, 2015). In addition, WECC creates a forum for the development of Regional Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC Bylaws (WECC, 2018). WECC oversees the largest and most geographically diverse region in the United States. Membership is open to all entities that meet the qualifications in the WECC Bylaws. WECC recently produced a Western Assessment of Resource Adequacy to complement NERC's Long-Term Reliability Assessment.
- **Western Interconnection Regional Advisory Body (WIRAB):** Following the petition of ten governors from western states, and in accordance with Section 215(j) of the Federal Power Act (FPA), FERC established WIRAB in 2006. WIRAB has the authority to advise FERC, NERC, and WECC on matters pertaining to electric grid reliability (and potentially resource adequacy-related issues) in the Western Interconnection. Membership includes representation from western states and Canadian provinces that serve load in the Western Interconnection. WIRAB works to achieve member consensus before submitting advice on reliability matters.

60 Some state public utility commissions have authority only over IOUs, whereas other states do have jurisdiction over publicly owned utilities.

- **Committee on Regional Electric Power Cooperation (CREPC):** Initially established in 1982 as joint committee of the Western Interstate Energy Board (WIEB) and the Western Conference of Public Service Commissioners (WCPSC), this committee is comprised of an energy office official and a regulatory utility commissioner from each of the states and provinces in the Western Interconnection.[61] The group works to examine electric power system policy issues that requires regional cooperation and coordination.
- **The Western Power Pool (WPP) and Western Resource Adequacy Program (WRAP):** The Northwest Power Pool (NWPP) was formed during World War II, when regional electric utilities and the Bonneville Power Administration pooled resources to support efforts during World War II (Kramer, 2010). It supports its members, to achieve the maximum benefits from coordinating the operations of their resources (NWCC, 2023). In 2023, FERC approved a tariff filed by the Western Power Pool (rebranded from the NWPP) to implement a Western Resource Adequacy Program (WRAP). Under this new paradigm, participating utilities will work to establish common resource adequacy standards and approaches (WPP, 2023). The WRAP currently offers an information-sharing forum that is non-binding. However, consideration is underway for potential binding tariff requirements for participating entities around a more formalized resource adequacy framework (WPP, 2023).

  The intent of WRAP is to ensure sufficient capacity among member utilities to meet a desired reliability standard. Two programs were established within the WRAP that require participating members to own or contract for sufficient capacity (and transmission for delivery) to meet their share of the collective reliability need:

  - **The Forward Showing Program (FS Program):** a forward-looking resource adequacy compliance program that requires participating "Load Responsible Entities" (LREs)—utilities and other retailers—to procure resources to meet a defined compliance obligation using resource-counting rules established by the WPP.
  - **The Operational Program (Ops Program):** an operations-focused capacity sharing program obligating WRAP members to hold back and share excess capacity during scarcity conditions. System conditions will be continuously reviewed for the upcoming seven days. In the event of a shortfall, members must facilitate bilateral transactions between participating entities at pre-established terms during the operational period.
- **Western Market Services:** In the absence of a western RTO, CAISO began offering grid services to other western states in 2014, while SPP followed five years later with the Western Energy Imbalance Service (WEIS) (SPP, 2022). Both RTOs have been expanding their grid services by providing load balancing services aimed at enhancing efficiency and reducing costs for their respective entities in the Western Interconnection. More recently, both RTOs are exploring voluntary day-ahead market services that would build on their current offerings. CAISO's final proposal for their Extended Day Ahead Market (EDAM), filed with FERC in August 2023, is designed to increase regional coordination, encourage the development of renewable energy resources, and lower costs for consumers. SPP is also proposing a day-ahead market, Markets+, which could be filed with FERC as early as the first quarter of 2024 (SPP, 2022). These developments have the potential to impact other resource adequacy and system planning processes in the west.

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61 The Western Interstate Energy Board (WIEB) is an organization of 11 Western States and 2 western Canadian Provinces. The Western Conference of Public Service Commissioners (WCPSC) is a regional association within the National Association of Regulatory Utility Commissioners (NARUC).

Resource Adequacy and Planning Processes

State Integrated Resource Planning

Resource adequacy in the non-market western interconnection is in transition and ongoing approaches continue at a state level. Under state IRP processes, utilities develop 20-year plans every two to four years, engaging in stakeholder processes to discuss forecasting, modeling, and analysis of resources and loads. These IRPs include specific state-mandated analysis that incorporates the utilities' preferred portfolio of resources over the next 10-20 years. Individual stakeholders include commission staff, customer advocates (residential, commercial, and industrial), energy project developers; environmental advocates; and interested citizens. Utilities that are the designated balancing authorities generally meet their resource needs through owned generation, bilateral contracts, and short-term firm market purchases for physical power.[62] Many utilities currently rely on short-term purchases to meet a portion of their peak load, and IRPs identify the volume of short-term purchases on which the utility relies (E3, 2019). The following two examples highlights IRP approaches in two western states: New Mexico and Arizona.

- **New Mexico:** The New Mexico Public Regulation Commission (NMPRC) regulates, among other things, natural gas, and electric utilities, and, to some extent, electric cooperatives operating within the state (NMPRC, 2023). The NMPRC issued an updated integrated resource plan (IRP) rule in 2022 that requires electric public utilities to file a proposed IRP every three years. The plan must specify how the implementation and use of those resource options would vary with changes in supply and demand. The rule provides that, in proposing cost-effective resources, utilities must prioritize resources that best comply with New Mexico's requirements for reducing greenhouse gas emissions, fostering equitable clean energy development, and grid modernization (NMPRC, 2022). Utilities must consider the procurement of distributed energy resources, demand response, energy efficiency, renewable energy, flexible generation, low-emission or zero-carbon resources, energy storage systems, and transmission and distribution grid improvements. In evaluating the plan, the NMPRC considers the estimated costs and environmental impact of associated transmission upgrades. While the NMPRC evaluates IRPs, it does not require its utilities to meet a specific reserve margin.

- **Arizona:** The Arizona Corporation Commission (ACC) oversees the electric power industry in Arizona, except for electric service provided by a city or municipality, irrigation district, electric district, or utilities operated by tribal authorities (ACC, 2023). The ACC's rules require that IRPs covering a 15-year period be prepared and submitted by load-serving entities in each evenly numbered year by April 1; however, adjustments to filing deadlines can be made by the ACC when extenuating circumstances are present (e.g., COVID-19). The IRPs should present scenarios and portfolios which compare the ability to reduce or shift electric usage (demand-side resources) in an equitable fashion to the ability to increase the production of electricity (supply-side resources). With input from interested parties, each IRP compares a wide range of resource options and considers factors such as reliability, deliverability, cost projections, environmental impacts, and water consumption (ACC, 2020).

  With respect to transmission facilities, the ACC requires electric utilities to submit an explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities. The explanation must include the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A), and any relevant provisions of the ACC's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona environmental regulations. The ACC's requirements for public electric utilities' reserve margins are discussed below in the Planning Reserve section.

62 Some of these short-term purchases are referred to as front office transactions, which are essentially short-term market purchases that used to meet near term resource adequacy requirements.

State Resource Adequacy Approaches

Through their state-specific processes, utilities use a variety of methods to establish resource adequacy targets and to set PRM (NPP, 2019). Their methods generally fall into one of two methods: deterministic or probabilistic. Deterministic methods plan for the single peak hour and add a fixed PRM to the generation necessary to meet the peak hour. Deterministic PRM standards are based on historical and expected loads and resources at peak (NPP, 2019; Gridworks, 2018). Most deterministic PRMs run from 13% to 17% of total peak generation need. The probabilistic method is somewhat more common than the deterministic method. The probabilistic approach includes variations in load, generation performance and outage assumptions, weather and other factors in an hourly model that runs thousands of repetitions of the target year to produce a distribution of outcomes. As needed, resources are added to the model to reach the desired resource adequacy standard. Most BAs use loss of load probability (LOLP) as the metric for measuring their resource adequacy standard. The NWPP previously adopted a 5% LOLP criterion, and many BAs in the west have adopted this standard for establishing a planning reserve target. Some utilities are also exploring the use of additional metrics to inform their resource adequacy standard, including LOLP, LOLE and EUE (NPP, 2019; NERC, 2017; Gridworks, 2018).

Western states, including Arizona and New Mexico, do not have specified planning reserve margins that jurisdictional electric utilities must meet, but commissions often require that public electric utilities to maintain sufficient generation capacity above their forecasted peak load to offset generator scheduled maintenance, forced and unplanned outages, higher than expected loads, system emergencies, system operating requirements, and reserve-sharing arrangements (NMPRC, 2018 (NMPRC, 2020). **Table 18** includes the planning reserve margins for the largest electric providers in New Mexico and Arizona.

Table 18: PRMs for Electric Providers in New Mexico and Arizona

Utility	2023 Planning Reserve Margin	Calculation Method (Based on)
EPE	10.1%	0.2 LOLE; EPE to move to a 0.1 LOLE in 2030 (NMPRC, 2019)
PNM	18%	0.2 LOLE (NMPRC, 2021); PNM moving to a 0.1 LOLE in 2023 IRP
SPS	15%	Planning Reserve Margin set by the Southwest Power Pool (SPP, 2023)
APS	15%	LOLE of one event in ten years (APS, 2020)
TEP	15%	15% Planning Reserve Margin Target (TEP, 2020)
SRP	16%	16% Planning Reserve Margin Target (SRP, 2020)

Regional Resource Adequacy Approaches

Under the WRAP, the determination of the PRM under the forward-looking program is supported by a probabilistic LOLE study, which analyzes the ability of generation to serve the WRAP footprint's P50 (median) peak load forecast. The goal is to implement a plan that avoids a loss-of-load event more frequently than once during a 10-year period during the summer and winter seasons, and once in a 10-year period for the winter season. The WPP has developed a "Detailed Design Document" for the program and is in the process of creating Business Practice Manuals that establish operational detail (WPP, 2023). In addition to resource adequacy analyses and planning conducted by utilities and other BAs, several organizations in the west conduct individual resource adequacy analyses but have no authority to require BAs to incorporate these findings and analyses (Carvallo et al., 2020).

The Western Power Pool (WPP) provides certain services to its members across the region. The WPP is a NERC-registered entity whose members or participants share contingency reserves to maximize generator dispatch efficiency. Although contingency reserve programs do not themselves constitute a resource adequacy plan or process, sharing contingency reserves reduces the costs of compliance with certain NERC balancing standards, and increases reliability across the Western Interconnection.

More recently, the WPP has undertaken a more formal and holistic role in resource adequacy in the WECC. This process began when many WPP members joined together to form a Resource Adequacy Program, later termed the Western Resource Adequacy Program, or WRAP. Their efforts were motivated by assessments by the Council, WECC, and independent analyses conducted for entities in the Western Interconnection that identified near- and long-term resource adequacy-related concerns for the region.

In response to these studies, WPP members came together in the summer of 2019 to review the resource adequacy posture of the region and consider next steps (Carvallo et al., 2020). In October 2019, the WPP members announced their intent to develop a Regional Resource Adequacy Program. They convened a steering committee of funding members, created a Stakeholder Advisory Committee, and developed a plan to implement a resource adequacy program. In August 2020, the WPP hired the Southwest Power Pool, Inc., to serve as the resource adequacy program developer.

Throughout 2021 to 2023, the WPP and its members developed its specific proposal for the WRAP, and engaged state commissioners, staff, and energy office officials in questions about how state representatives could participate in the governance and design of the WRAP. This collaboration with state utility commissions was intended to serve at least two important purposes. First, it was intended to give more clarity to utility regulators about how they could weigh in on regional resource adequacy determinations, in recognition of the fact that they had historically regulated it solely through state-led processes for their jurisdictional utilities, and in recognition of the fact that they would continue to have authority over the topic into the future. Second, it was intended to provide WRAP participants with some assurance that their respective state utility regulators would have equal participation to avoid determinations related to resource adequacy requirements or cost recovery implications that were inconsistent with the program's design.

Part of the resolution of these discussions was the creation of the Committee of State Representatives (COSR), which has formal comment and review opportunities within the structure of the WRAP. The COSR is made up of representatives from the state commission or energy office of each state that regulates an entity that is participating in the WRAP.

The WPP eventually submitted a formal tariff to FERC, seeking approval to implement the WRAP. FERC approved the program in early 2023. Under the program design, WRAP measures resource adequacy on a collective participant basis to determine a set of reliability metrics and then determines each participant's short or long position. The common resource adequacy standard, as determined on a wide-area footprint, is expected to lower the PRM of the WRAP footprint and allow for the standardization of capacity products to enable participants to trade, on a bilateral basis, a common capacity product. Under the WRAP, each participant will need to make a forward (future) showing of sufficient resources to meet the resource adequacy standard for two binding seasons (summer and winter). The program will monitor each participant's resource adequacy position from seven months ahead to the day ahead (1 day prior to the operating day), avoiding double-counting of capacity (WPP, 2021). One of the goals of the WRAP is to increase visibility and coordination across participants to paint a clearer regional picture of resource needs and supply. It seeks to address resource adequacy through collaboration, ultimately leveraging a diverse pool of resources over a large geographic area to improve operational efficiencies (WPP, 2023).

WRAP is voluntary and not imposed on any load-serving entity in the west. Once a participant joins, however, it undertakes binding obligations, and subjects itself to charges in the event it fails to bring capacity that satisfies the program mandates.

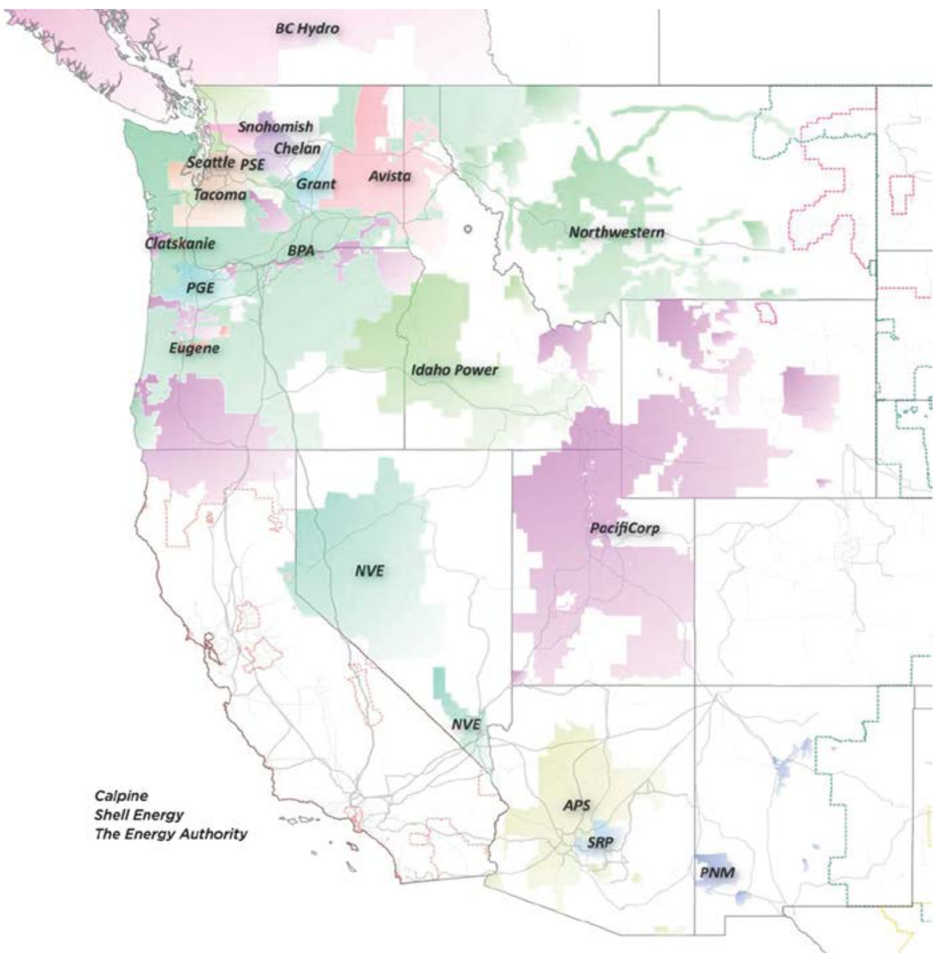
Most entities in the West rely to some extent on imports to remain resource adequate. Weather events and transmission availability play a critical role in whether imports can be relied upon. The WRAP was established to help navigate through these challenges. In addition to this new program, WECC works with its Electric Reliability Organization partners to produce three resource adequacy assessments each year: a long-term reliability assessment (10-year outlook) and two seasonal reliability assessments (summer and winter).

The intent of WRAP is to ensure sufficient capacity among member utilities to meet a desired reliability standard. Two programs were established within the WRAP that require participating members to own or contract for sufficient capacity (and transmission for delivery) to meet their share of the collective reliability need:

- **The Forward Showing Program (FS Program):** a forward-looking resource adequacy compliance program that requires participating "Load Responsible Entities" (LREs)—utilities and other retailers—to procure resources to meet a defined compliance obligation using resource-counting rules established by the WPP.
- **The Operational Program (Ops Program):** an operations-focused capacity sharing program obligating WRAP members to hold back and share excess capacity during scarcity conditions. System conditions will be continuously reviewed for the upcoming seven days. In the event of a shortfall, members must facilitate bilateral transactions between participating entities at pre-established terms during the operational period.

As of September 2023, the WRAP includes 22 entities in the United States and Canada (**Figure 22**).

Figure 22: Map of Inaugural WRAP Participants (GridLab, 2023)



Resource Adequacy Reforms and Reliability Issues

As described above, resource adequacy in the non-market western interconnection is evolving and dynamic, as the WRAP program moves from a non-binding phase into a binding phase (sometime between 2026 and 2028). Additionally, it remains dynamic because the details of WRAP continue to evolve and be codified, and because some utilities in the West may not participate in the WRAP.

From a high-level perspective, the West appears to be facing substantially increased pressures related to resource adequacy. Although the West has had adequate capacity for many years, several assessments have indicated that, without responsive action, portions of the region could become capacity constrained in the near-term (NPCC, 2022; WECC, 2021). Concerns are prompted by a combination of the following factors (E3, 2022):

- Utility reliance on short-term purchases to meet peak conditions;
- Changes in the resource mix, including the reduction of dispatchable generation in the region (retirement of coal-fired generation) and growth in solar and wind resources;
- Changes in hydroelectric generation due to climate and precipitation changes; and
- Increased uncertainty of the shape of demand.

A major transition of resources is being substantially driven by state policies in some western states related to decarbonization of generating resources. These policies are increasing and accelerating the proliferation of non-dispatchable renewable resources in the West, and generally necessitating the development and installation of new and greater storage technologies along with the installation of solar, wind, and other renewable resources. These dynamics increase the challenges associated with resource adequacy and are likely to require new methods for managing and operating the grid in the Western Interconnection.

Fossil-Fuel Retirements and Carbon-Free Replacements in the Southwest

A key trend in the southwest part of the region is increased reliance on renewables and battery energy storage along with load growth as many utilities retire coal and natural gas-fired plants. New Mexico's Energy Transition Act was intended to transition New Mexico away from fossil-fuel generation by setting a statewide renewable energy standard of 50% by 2030 for New Mexico investor-owned utilities and rural electric cooperatives and a goal of 80% by 2040, in addition to setting zero-carbon resources standards for investor-owned utilities by 2045 and rural electric cooperatives by 2050 (NMCC, 2023). In New Mexico, the San Juan coal-fired generating station was retired in September 2022, and the utility plans to add a significant amount of new solar and storage as part of the San Juan replacement portfolio (NMPRC, 2023). This includes the addition of the Arroyo Solar and Storage Project that includes a 300 MW(AC) solar generation facility and a 150 MW battery energy storage system located in McKinley County, New Mexico.

The Palo Verde Nuclear Generating Station has been the nation's largest power producer for more than 25 years, generating more than 32 million megawatt-hours annually (APS, 2023). The plants ownership is spread among multiple utilities: APS (29.1% tenant-in-common interest); the Salt River Project (17.49%), PNM (10.2%); EPE (15.8%); with the rest shared between multiple California-based utilities (NRC, 2022). EPE has reduced its carbon footprint, becoming the first coal-free utility in New Mexico and Texas and has since obtained required regulatory approvals for purchased power agreements to expand renewable energy and energy storage projects. EPE aims to have the new facilities online by 2025 which will provide more than 450,000 MWh of generation in their first year of operation (EPE, 2022). In New Mexico, Kit Carson Electric Cooperative Inc. often provides its daytime energy demand entirely with solar power (Kit Carson, 2022).

Extreme Weather in the Southwest

The Southwest is facing challenges related to climate change, including extreme weather conditions that create uncertainty and pose a risk to reliability. The extreme summer temperatures, regional heatwaves, and prolonged drought conditions create challenges to the generation and transmission of electricity. In addition to potentially contributing to an increased risk of outages, prolonged periods of high temperatures can significantly reduce generator output – particularly reduced water availability used for cooling most thermal resources (E3, 2022).

Wildfire Risk

The Southwest region's hot and dry weather creates higher potential for wildfires, a risk that utilities work year-round to mitigate. For example, APS has a Wildfire Mitigation team in place that focuses on reducing the risk to communities. Inspecting the condition of transmission and distribution equipment is a crucial aspect of fire prevention. APS uses drones and helicopters to inspect areas that crews cannot safely access. APS also uses a vegetation management program to clear trees and foliage from areas around power lines and equipment to help prevent fires resulting from contact (APS, 2023).

Additional Information on Resource Adequacy in the Non-Market Western Interconnection

- *WECC System Performance Data Portal* – Western Electricity Coordinating Council (Link)
- *About the Western Energy Imbalance Market* – Western Energy Imbalance Market (Link)
- Western Resource Adequacy Program (Link)
- WECC – 2022 Western Assessment of Resource Adequacy (Link)

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1101 Vermont Ave, NW • Suite 200 • Washington, DC 20005
www.naruc.org • (202) 898-2200